Aurora Energy, LLC Chena Power Plant BACT Appendix

1990-08 NSPS ICI SO2 RE.pdf
2017-03 Aurora BACT Report.pdf
2017-11-16 ADEC BACT Comment Letter to Aurora.pdf
2017-11-16 ADEC Request for Additional Information for Chena Power Plant BACT Analysis.pdf
2017-11-16 EPA Comments on Aurora BACT 111517.pdf
2017-11-16 Voluntary BACT Analysis Letter Aurora 042415.pdf
2017-12-22 Aurora Response to ADEC BACT Information Request 1.pdf
2017-12-22 ERM Final BACT Addendum for Aurora.pdf
2018-09-10 ADEC Request for Additional Information for Chena Power Plant BACT Analysis.pdf
2018-09-13 ADEC BACT Comment Letter to Aurora.pdf
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2018-11-01 Aurora BACT Proposal No. 1899-R1.pdf
2018-11-01 Aurora General Arrangement Photo.pdf
2018-11-01 Aurora Preliminary Opinion of Probable Cost with attachments.pdf
2018-11-01 Aurora Preliminary Opinion of Probable Cost.pdf
2018-11-01 Aurora Response to ADEC BACT Information Request 2 with enclosures.pdf
2018-11-01 Aurora Response to ADEC BACT Information Request 2.pdf
2018-11-01 Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf
2018-11-01 CDS v SDA Cost Comparison for Aurora.pdf
2018-11-01 ICI Boilers 20081118 final_revised-Jan2009.pdf
2018-11-01 NSPS ICI SO2 RE.pdf
2018-11-01 ufc_3_701_01_c1_2018.pdf
2018-11-19 Aurora Proposed BACT Alternative with Appendices.pdf
2018-11-19 Aurora Proposed BACT Alternative.pdf
2019-05-10 Appendix A.pdf
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2019-05-10 Public Notice Chena BACT Determination.pdf
2019-07-26 AE Comments on Draft SIP.pdf
2019-07-26 BACT Analysis Addendum - Ind Eng Eval_Final_20.pdf
2019-07-26 David Fish e-mail Aurora Energy, LLC's Comments on Draft SIP.pdf
2019-07-26 David Fish e-mail Usibelli Coal Mine, Inc. Comments on Draft.pdf
2019-07-26 UCM Comments on Draft SIP.pdf
2019-11-13 Chena Power Plant Response to Comments.pdf
2019-11-13 Final Chena BACT Determination.pdf

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

2017-03 Aurora NOx cost calcs FINAL.XLSX
2017-03 SO2 cost calcs - LSFO - CUECOST3.xlsx
2017-12-22 FINAL-CUECost Calculator.xlsx
2017-12-22 FINAL-DSI Cost Calculator.xlsx
2019-11-13 Chena SCR Economic Analysis ADEC.xlsm
2019-11-13 Chena SNCR Economic Analysis ADEC.xlsm
2019-11-13 Chena SO2 Controls Economic Analyses.xlsx

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park NC 27711
EPA-450/3-90-016
August 1990
Air

EPA

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

EPA-450/3-90-016

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1990

2.3.3 Percent Reduction Standard

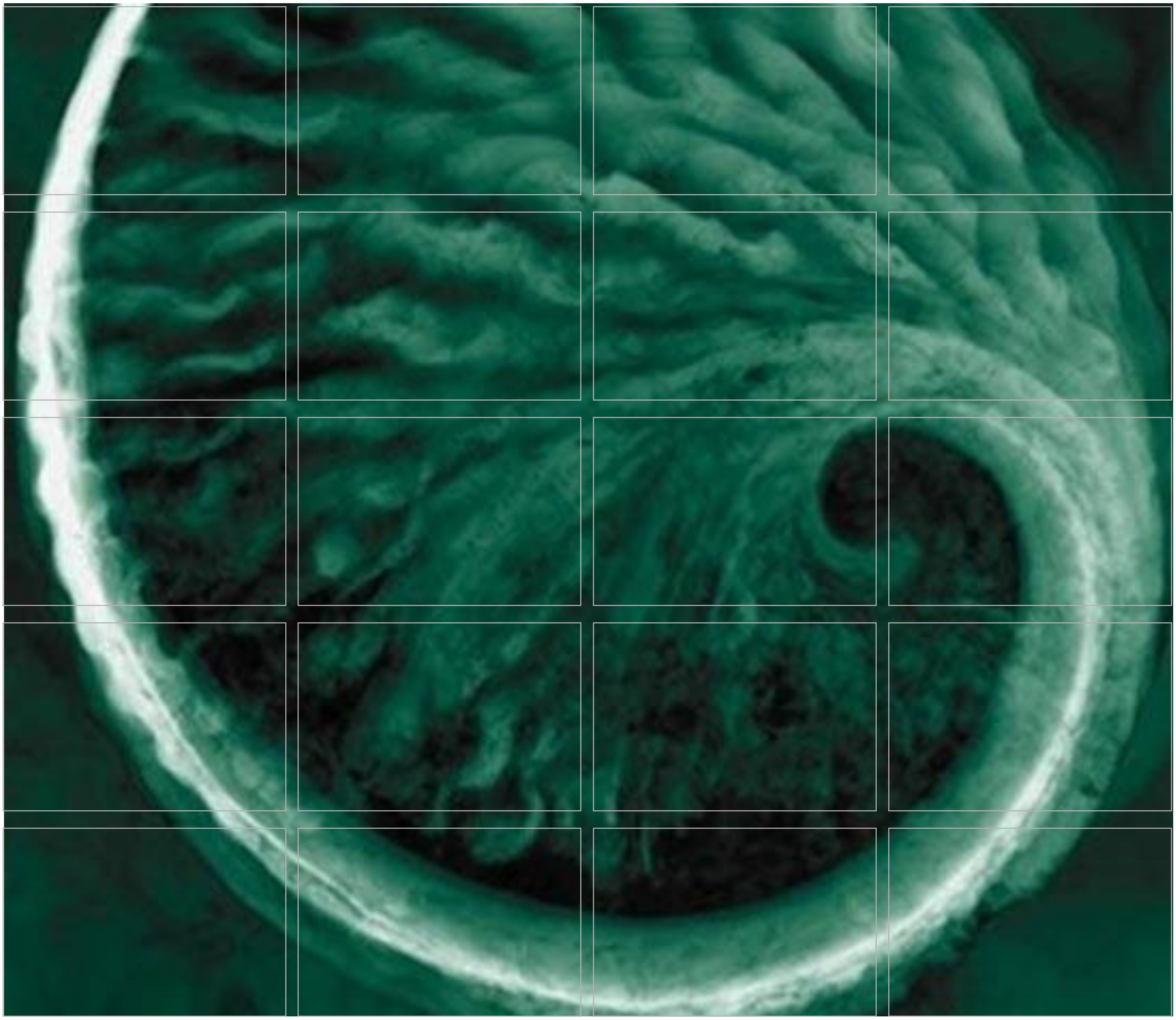
1. Comment: Two commenters (IV-D-08, IV-D-28) requested that the 90 percent SO_2 reduction requirement be eliminated and replaced with an emission limit of 520 ng/J (1.2 lb/million Btu) heat input. One commenter (IV-D-08) objected to applying the 90 percent SO_2 reduction requirement to all coal regardless of sulfur content. This commenter stated that the EPA's conclusion that no units will be built in the size range between 22 and 29 MW (75 and 100 million Btu/hr) heat input capacity and operating at greater than 55 percent capacity factor is flawed. This commenter stated that the SO_2 standard of 520 ng/J (1.2 lb/million Btu) heat input for coal-fired plants should apply to all steam generating units in this source category, regardless of size. This commenter further recommended that the full 90 percent SO_2 removal be required only when the 520 ng/J (1.2 lb/million Btu) limit could not be met by using low sulfur coals or by pretreating the coals.

Another commenter (IV-D-28) stated that the 90 percent SO_2 reduction requirement should be removed and that coal-fired steam generating units in the 8.7 to 29 MW (30 to 100 million Btu/hr) range should be required only to meet the 520 ng/J (1.2 lb/million Btu) SO_2 limit. The commenter stated that the percent reduction requirement would place an unjustified cost and performance burden on units in this range that either already meet or are close to meeting the 520 ng/J (1.2 lb/million Btu) SO_2 limit.

Response: Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the

Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable. As discussed in the background document, "Model Boiler Cost Analysis for Controlling Sulfur Dioxide (SO_2) Emissions from Small Steam Generating Units" (EPA-450/3-89-14), a small coal-fired steam generating unit of 22 MW (75 million Btu/hr) size and operating at a 55 percent capacity factor has an incremental cost-effectiveness value of about $3,600/Mg ($3,300/ton) relative to an emission limit standard of 520 ng/J (1.2 lb/million Btu). Capital and annualized costs are projected to increase by approximately 20 percent over the regulatory baseline for the percent reductions standard. However, these values increase significantly for units less than 22 MW (75 million Btu/hr) heat input capacity and for any unit less than 29 MW (100 million Btu/hr) operating at an annual capacity factor for coal of less than 55 percent. Imposing these high costs for these units was considered to be unreasonable when compared to the increase in emission reductions achievable by the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less.

Finally, no conclusion was made that coal-fired steam generating units greater than 22 MW (75 million Btu/hr) heat input and greater than 55 percent capacity factor would not be built. Rather, this was a projection of sales over the next five years based on sales trends over the past several years. The sales projections for coal-fired units had no influence on the conclusion of the reasonableness of the percent reduction requirement. (The assumption was used in generating national impacts of the standards.) The model steam generating unit analysis examined the potential impacts of the percent reduction requirement on a coal-fired unit greater than 22 MW (75 million Btu/hr) and greater than 55 percent capacity factor. Therefore, should a unit be built, requiring 90 percent reduction of emissions would be reasonable.



Best Available Control Technology Analysis

Chena Power Plant, Fairbanks, Alaska

March 2017, revised

www.erm.com

Best Available Control Technology Analysis

Chena Power Plant, Fairbanks, Alaska

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ACRONYMS AND ABBREVIATIONS

acfm	actual cubic feet per minute
ADEC	Alaska Department of Environmental Conservation
BACM	best available control measures
BACT	best available control technology
CAA	Clean Air Act
CMAQ	Community Multiscale Air Quality
CMB	chemical mass balance
dscf/min	dry standard cubic feet per minute
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FGR	flue gas recirculation
FNSB	Fairbanks North Star Borough
GVEA	Golden Valley Electric Association
HC	hydrocarbon
HNO_3	nitric acid
LAER	Lowest Achievable Emission Rate
LAF	Location Adjustment Factor
lb/hr	pound per hour
LEA	lean excess air
LNB	low-NOx burners
LSFO	limestone forced oxidation
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NGR	natural gas reburning
NH_3	ammonia
NNSR	nonattainment new source
NOx	oxides of nitrogen
NSCR	non-selective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review

OFA	over-fire air
OH	hydroxyl
PM	particulate matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
RACM	reasonably available control measures
RACT	reasonable available control technology
RFP	Reasonable Further Progress
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SSF	Site Sensitivity Factor
ton/yr	tons per year
U.S.	United States
V_2O_5	vanadium pentoxide
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic

1 INTRODUCTION AND BACKGROUND

1.1 PROCEDURAL MATTERS RELATED TO $PM_{2.5}$ NONATTAINMENT

The Clean Air Act (CAA) requires the U.S. Environmental Protection Agency (EPA) to set air quality standards (40 CFR Part 50) to protect the health and welfare of the public and the environment. In partial fulfillment of this charge, U.S. EPA has set National Ambient Air Quality Standards (NAAQS) for six principal criteria air pollutants, including particulate matter (PM), to ensure that health and environmental protection are adequate based on the scientific justifications. In 1997, U.S. EPA established annual and 24-hour NAAQS for $PM_{2.5}$. In 2006, U.S. EPA lowered the 24-hour ambient $PM_{2.5}$ standard from 65 micrograms per cubic meter ($\mu g/m^3$) to 35 $\mu g/m^3$. States were required to examine monitoring data collected within their communities and make designation recommendations based on the new standard by December 2007. In 2009, U.S. EPA designated the Fairbanks North Star Borough (FNSB) as nonattainment for the 24-hour $PM_{2.5}$ standard. As a result of this designation, and as described below, the Alaska Department of Environmental Conservation (ADEC) was required to prepare a State Implementation Plan (SIP) that defined those actions needed to bring the FNSB into attainment of the NAAQS.

In March 2012, the U.S. EPA issued a document specifically to guide states in preparing their SIP submissions and meeting plan requirements for the 2006 24-hour $PM_{2.5}$ NAAQS. The guidance for the 2006 $PM_{2.5}$ NAAQS was based, in large part, on the requirements finalized in the 2007 $PM_{2.5}$ Implementation Rule, which the U.S. EPA had based solely upon the statutory requirements of CAA Part D, Subpart 1. Under those provisions, states were required to submit a SIP within 3 years following a designation of nonattainment. Alaska's effective date of the FNSB designation as a nonattainment area was December 14, 2009. Alaska's original SIP submittal due date under CAA Part D, Subpart 1, therefore, was December 14, 2012. However, on January 4, 2013, the DC Circuit Court ruled that the CAA requires implementation of the $PM_{2.5}$ NAAQS under CAA Part D, Subpart 4 (Sections 188-190) rather than implementation under Subpart 1. Subsequently, on June 2, 2014, U.S. EPA published a new rule that identified $PM_{2.5}$ "Moderate" nonattainment areas and proposed December 31, 2014 as the new submittal due date of a Subpart 4 SIP to U.S. EPA. The SIP was required to demonstrate, using air quality modeling, that attainment was either possible or impracticable by December 31, 2015.

1.2 RECLASSIFICATION FROM MODERATE TO SERIOUS

On December 31, 2014, ADEC submitted the FNSB $PM_{2.5}$ Moderate Nonattainment Area SIP that demonstrated through air quality modeling that it would be impracticable to attain the 24-hour $PM_{2.5}$ NAAQS by December 31, 2015. U.S. EPA was to review ADEC's impracticable demonstration and conduct an independent analysis of the FNSB air quality. ADEC made additional submissions and provided clarifying information to supplement the SIP in January 2015, March 2015, July 2015, November 2015, March 2016, November 2016, and January 2017. The original SIP and all subsequent submissions are included in U.S. EPA Docket ID EPA-R10-OAR-2015-0131.[1] On November 20, 2015, ADEC submitted a request to U.S. EPA to redesignate the boundary of the FNSB $PM_{2.5}$ Nonattainment Area by dividing it into two separate areas. The request would divide the area along Badger Road, resulting in a western area containing Fairbanks and an eastern area containing North Pole. U.S. EPA has up to 18 months (May 2017) to evaluate and either approve or disapprove the request. Regardless, the U.S. EPA was still required to determine whether the FNSB was able to attain the 24-hour $PM_{2.5}$ NAAQS by the December 31, 2015, deadline and to publish a notice of the determination in the Federal Register by June 30, 2016. If the area did not attain the 24-hour $PM_{2.5}$ NAAQS, the area would be reclassified by operation of law as a Serious nonattainment area.

On October 11, 2016, two environmental groups filed a complaint for declaratory and injunctive relief against U.S. EPA arguing that it failed to fulfill its statutory duty under the CAA to declare whether or not the FNSB nonattainment area has attained the standard by the June 30, 2016 deadline. The complaint also requested that the court declare that the U.S. EPA is in violation of the CAA and issue an injunction requiring the agency to publish a notice regarding the FNSB attainment/nonattainment status and, if the area is found to still be nonattainment, to reclassify it as Serious nonattainment. On December 16, 2016, U.S. EPA published a proposed rule proposing to determine that the FNSB failed to attain the 2006 24-hour $PM_{2.5}$ NAAQS by December 31, 2015 and proposing to reclassify the area from Moderate to Serious pursuant to CAA section

[1] Fairbanks $PM_{2.5}$ Moderate Area Plan Regulatory Docket - https://www.regulations.gov/docket?D=EPA-R10-OAR-2015-0131

188(b)(2).[2] As required by CAA Section 188(b)(2), upon finalization of the U.S. EPA's determination that the area failed to attain, the FNSB will be reclassified to Serious by operation of law and will be subject to all applicable Serious area attainment planning and nonattainment new source review (NNSR) requirements.

On February 2, 2017, the U.S. EPA published a proposed rule proposing to approve the Moderate SIP for the FNSB 24-hour $PM_{2.5}$ (2006) NAAQS.[3] Once the area is reclassified from Moderate to Serious, pursuant to Subpart 4, ADEC will have 18 months from the effective date of reclassification, or 2 years before the attainment date, whichever is earlier, to submit a Serious area attainment plan. This submittal date would be no later than December 31, 2017. However, CAA Section 188(d) provides a mechanism by which ADEC may request, and the U.S. EPA may grant, a 1-year extension of an area's attainment date if the State meets certain criteria.

The Serious area attainment plan must include the imposition of control measures consistent with best available control measures (BACM), which includes application of best available control technology (BACT) for major stationary sources, with the goal of bringing the area into attainment as expeditiously as practicable, but no later than the end of the 10th calendar year after designation.

1.3 REQUIREMENT TO INCORPORATE BACM/BACT

Implementation of $PM_{2.5}$ NAAQS under CAA Part D, Subpart 4 includes the following state requirements related to the nonattainment area:

- Submit an attainment demonstration or demonstration that attainment by the applicable attainment date is impracticable [Section 189(a)(1)(B)];

[2] Federal Register, Volume 81, page 91089, December 16, 2016, 40 CFR Part 52 and 81, Determinations of Attainment by the Attainment Date, Determinations of Failure To Attain by the Attainment Date and Reclassification for Certain Nonattainment Areas for the 2006 24-Hour Fine Particulate Matter National Ambient Air Quality Standards

[3] Federal Register, Volume 82, February 2, 2017, 40 CFR Part 52, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

- Assure implementation of reasonably available control measures (RACM) and reasonable available control technology (RACT) for Moderate nonattainment areas [Section 189(a)(1)(C)];

- Assure implementation of BACM and BACT no later than 4 years after the date the area is classified (or reclassified) as a Serious nonattainment area [Section 189(b)(1)(B)];

- Redefine the terms "major source" and "major stationary source" to include any stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the potential to emit, at least 70 tons of $PM_{2.5}$ (or $PM_{2.5}$ precursors) per year; and

- Apply $PM_{2.5}$ precursor control requirements for major stationary sources [Section 189(e)].

On March 23, 2015, U.S. EPA published a proposed rule entitled, "Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements" that provides additional guidance to affected states related to the requirements listed above. The final rule was promulgated on August 24, 2016.[4] In this rule, U.S. EPA also defined requirements that agencies would have to meet as they implement the NAAQS for $PM_{2.5}$. Various aspects of this rule are relevant to the process for evaluating what constitutes BACT at a major stationary source. Because implementation of BACT in a Serious nonattainment area is not a traditional process, incorporation of some of the nuances associated with the final rule and its potential interpretation are considered justified herein.

An important aspect of the final rule relates to whether a particular $PM_{2.5}$ precursor is determined to be a significant contributor to ambient $PM_{2.5}$ levels. Scientific research has shown that various pollutants can contribute to ambient $PM_{2.5}$ concentrations. In addition to direct $PM_{2.5}$ emissions, these include the following precursors:

- sulfur dioxide (SO_2);
- oxides of nitrogen (NOx);

[4] Federal Register, Volume 81, pages 58010 through 58162, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

- volatile organic compounds (VOC); and
- ammonia (NH_3).

These gas-phase precursors undergo chemical reactions in the atmosphere to form secondary $PM_{2.5}$.

The final rule describes how in some cases a state may demonstrate that the adoption of additional emission reduction measures for a particular precursor is not needed for purposes of achieving expeditious attainment nor for advancing the attainment date by at least a year in a nonattainment area. The rule also describes three optional approaches for demonstrating that a particular precursor is not a significant contributor to ambient $PM_{2.5}$ levels that exceed the standard in a particular nonattainment area. These three precursor demonstrations are: (1) comprehensive precursor demonstration; (2) major stationary source precursor demonstration; and (3) NNSR precursor demonstration.

These three precursor demonstrations are described below:

1. A comprehensive precursor demonstration would show that emissions of a particular precursor from all existing stationary, area, and mobile sources located in the nonattainment area do not contribute significantly to $PM_{2.5}$ levels that exceed the standard in the area.
2. A major stationary source precursor demonstration differs from the comprehensive demonstration in that it only evaluates existing major sources, and therefore may only be used to justify the exclusion of existing major sources from the control requirements for the applicable precursor.
3. A NNSR precursor demonstration is part of any Moderate or Serious area plan. This specific type of precursor demonstration is the only one of the three demonstrations described in this section that if approved would exempt new and modified major stationary sources of a precursor from regulation under the NNSR permitting program.

If the U.S. EPA approves a comprehensive precursor demonstration for a Moderate or Serious plan, then the state would not be obligated to evaluate RACM/RACT or BACM/BACT measures, as appropriate, for reducing that precursor in the nonattainment area, nor would it need to account for that precursor in the Reasonable Further Progress (RFP) plan, quantitative milestones, and contingency measures. If a major stationary source precursor demonstration is approved, then the state would not be obligated to evaluate RACM/RACT or BACM/BACT measures for reducing that precursor from major sources in the nonattainment area, nor would it need to account for emissions of that precursor from major sources in the RFP plan, quantitative milestones, and contingency measures.

The first two of these demonstrations relate to existing sources in a nonattainment area. Even if a state fails to make demonstration, however, or if the U.S. EPA fails to approve a state demonstration, lack of a significant contribution to $PM_{2.5}$ nonattainment by a stationary source should be considered an important feasibility factor in the environmental evaluation included in a RACT or BACT analysis (see section 1.5 for a discussion of the BACT evaluation process). Although a Serious plan is not yet required for the FNSB, U.S. EPA has proposed to approve the ADEC Moderate SIP precursor demonstration for major stationary sources of NOx and for all sources of VOCs within the FNSB nonattainment area. In making this proposal, U.S EPA concluded that it is not necessary to evaluate and impose controls on major stationary sources of NOx in the Moderate plan.[5] By extension, this same conclusion would be expected for any precursor demonstration that is part of a future FNSB Serious SIP.

1.4 *HISTORIC PERSPECTIVES IN BACT*

The control concept that represents use of BACT on air pollutant sources has been in existence since the mid-1970s. BACT is part of a hierarchical approach to air pollution control based in part on the air quality in the area in which a stationary source was, or would be, located. The hierarchy specified three differing degrees of air pollution control depending on whether an area was in attainment of the prescribed NAAQS and whether the source requiring control was existing or new. BACT was specified to be applicable only to new sources in areas that were in attainment of the NAAQS. In comparison, new sources in nonattainment areas were required to apply technology producing the Lowest Achievable Emission Rate (LAER), whereas existing sources in nonattainment areas were required to apply RACT. No parallel concept exists for existing sources in attainment areas.

In general, the distinction between the three levels of control introduced above is a cost consideration. Economics play the greatest role when

[5] Federal Register, Volume 82, page 9042, February 2, 2017, 40 CFR Part 52, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

identifying RACT for a source. Although no hard-fast cost line exists, a source is required to apply RACT only if the cost is "reasonable." An economic test also is required when defining BACT, but an underlying acceptance is that the economic threshold for BACT is higher than for RACT. One rationale for this acceptance is that, because BACT is (until the concept of nonattainment BACT was conceived) only applied to new sources, one can include pollution control technology considerations during the design stage. Contrary to RACT and BACT, no cost consideration is given to specification of LAER technology, this due to the fact that already "dirty" areas must be protected at all costs from further degradation. The hierarchy generally described herein leads to the conclusions that RACT requirements are typically less stringent than BACT, and BACT requirements are less stringent than LAER. All three levels of control rely on application of demonstrated control techniques, as opposed to innovative technologies or techniques that have not been fully developed or demonstrated in practice.

1.5 APPLICATION OF BACT TO STATIONARY SOURCES

Since originally defined in the mid-1970s, the process of making a BACT determination has undergone numerous refinements. Specification of "nonattainment BACT" in the CAA is the most recent, and perhaps the most complex, refinement. Until that time, BACT requirements were limited to new major source review activities in attainment areas (i.e., the regulations for Prevention of Significant Deterioration [PSD]). Since the promulgation of the PSD regulations, preconstruction review for new or modified major air pollutant sources located in clean air areas (i.e., attainment areas) has always required an evaluation of the use of BACT. Although the specific procedures have varied over the decades, the PSD BACT evaluation entails a pre-construction review that demonstrates that BACT will be applied on a pollutant-by-pollutant basis for each air pollutant emitted at a rate that exceeds its pollutant-specific PSD significant emission rate. Selection of a BACT emission limit is a case-by-case process that must consider site-specific aspects of the project, including the economics of the selection as well as the environmental and energy impacts that could result from the use of the technique or technology.

Aside from the CAA specification of nonattainment BACT, two other historic "refinements" define the character of a BACT determination or demonstration, and both are related to the manner in which technologies are ranked for consideration. The more significant refinement of the two is adoption of the BACT analysis "top-down" procedure published in U.S.

EPA's draft 1990 New Source Review (NSR) Workshop Manual. This top-down procedure identifies the following steps as part of a BACT review:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness (highest to lowest)
4. Evaluate the most effective controls (using economic, environmental, and energy criteria) and document results
5. Select BACT.

The third step in this process, rank remaining control technologies by control effectiveness, is the heart of the top-down approach. This step requires that, after technically infeasible control options have been eliminated, the remaining technology with the greatest degree of control should be considered BACT unless one of the other evaluation criteria indicates an adverse impact will result. While this review process appears to be very well defined, the level at which a specific evaluation criterion would be considered "adverse" is not clearly defined; this uncertainty often provides the basis for extensive debate between the source operator and the permitting authority.

A second historic refinement relates to another new source regulatory program, the New Source Performance Standards (NSPS). The NSPS are applicable nationwide to industrial sources that meet the "new source" applicability date established by U.S. EPA for many categories of industrial emitters, including coal-fired (and other fossil fuel-fired) steam generators and utility boilers. The NSPS are designed to implement the best technology currently available, taking into account cost and energy impacts. Unlike the case-by-case aspect of BACT, these standards are the same for every new emitter. When one exists, an NSPS represents the minimum requirement that will be imposed on a new air pollutant source. New sources undergoing PSD review could possibly be required to meet more stringent emission limits than imposed by NSPS. Thus, no BACT determination can conclude that a BACT emission limit is less stringent than an applicable NSPS. As explained by U.S. EPA in response to numerous requests for interpretations:

> "Since an applicable NSPS must always be met, it provides a legal 'floor' for the BACT, which cannot be less stringent."

Presently, as the U.S. EPA and states are developing plans to bring areas into attainment of the NAAQS for PM_{10} and $PM_{2.5}$, U.S. EPA has determined that further refinement of the BACT process may be in order.

U.S. EPA has, therefore, included a multi-faceted discussion of evaluating BACT in Serious nonattainment areas in the March 23, 2015, proposed rule and August 24, 2016, final rule. Part of the discussion relates nonattainment BACT to other BACT evaluations and concludes similarity to existing BACT evaluation procedures. Another part of the discussion is less related to the manner in which a BACT evaluation is performed and more related to the proposed manner in which BACT might actually be implemented in a Serious $PM_{2.5}$ nonattainment area.

Two aspects of the newly-conceived nonattainment BACT requirement make this regulatory concept very difficult to implement. The first aspect is related to retrofitting an existing source with new (BACT) equipment. This potential requirement eliminates the economic efficiency of installing add-on control equipment to a new source as is typically done as an outcome of a BACT determination. Another aspect of a nonattainment BACT evaluation that leads to implementation difficulty, as mentioned earlier in Section 1.3 of this BACT report, is the use of optional precursor demonstrations. In some $PM_{2.5}$ nonattainment areas, a particular precursor or precursors may not contribute significantly to $PM_{2.5}$ levels that exceed the relevant NAAQS.[6] Thus, adoption of additional emission reduction measures for a particular precursor may not be needed for purposes of achieving expeditious attainment. In evaluating the various precursor demonstration options, U.S. EPA generally agreed that a significance level could be established for the contribution of a particular precursor source group to the total ambient $PM_{2.5}$ concentration. In its 2016 Draft $PM_{2.5}$ Precursor Demonstration Guidance, U.S. EPA recommended an insignificant threshold value of 1.3 $\mu g/m^3$ for the 24-hour $PM_{2.5}$ NAAQS as the level of insignificance that would eliminate the need to establish a control measure for the source or source category.[7] This concept is important when considering the environmental benefits of any mandated control measure as it relates to defining BACT for existing sources in a nonattainment area. However, lack of final guidance on the manner in which a BACT analysis should incorporate a finding of insignificant improvement in air quality concentrations for the nonattainment area pollutant (other than by a state demonstration described above) leaves implementation of nonattainment BACT open-ended.

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[6] Federal Register, Volume 81, page 58017, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

[7] Page, Stephen D., Director Office of Air Quality Planning and Standards, Draft $PM_{2.5}$ Precursor Demonstration Guidance, November 17, 2016.

1.6 AURORA ENERGY AND THE CHENA POWER PLANT

Aurora Energy LLC (Aurora) owns the Chena Power Plant in downtown Fairbanks, Alaska, within the FNSB. The Chena Power Plant consists of four, sub-bituminous coal-fired boilers, which produce electricity and locally-distributed steam. The PM produced during coal combustion in the Chena Power Plant boilers is currently controlled by a single baghouse and is emitted through a combined stack (capacity of 250,000 actual cubic feet per minute [acfm]). Table 1 summarizes the Chena Power Plant boilers and emissions measured during the most recent emission testing, performed in November 2011. As shown in Table 1, the Chena Power Plant has the potential to emit, primarily from their four coal-fired boilers, at least 70 tons of $PM_{2.5}$ precursors per year (SO_2 and NOx). Therefore, Aurora Energy is subject to the nonattainment BACT analysis requirements for SO_2 and NOx. $PM_{2.5}$ is already adequately controlled through the use of a baghouse, and no further control technique review is required for PM.

1.7 RELEVANT FEATURES OF THE ALASKA SIP

1.7.1 Identification of Relevant Control Technologies

The ADEC prepared a full control technology evaluation as part of the SIP and concluded that stationary source control should concentrate on primary $PM_{2.5}$ emissions and that control of secondary $PM_{2.5}$ emissions would be ineffective in bringing about attainment. The ADEC performed a traditional RACT evaluation for SO_2 and NOx produced during coal combustion for each specific coal combustion source in the FNSB. The ADEC concluded that the continued use of low sulfur coal at industrial and utility boilers represents RACT for SO_2. This conclusion is consistent with historic SO_2 control concepts employed by the U.S. EPA. The ADEC also concluded that use of add-on control equipment to reduce NOx emissions during coal combustion was too expensive and much less technically effective than control programs designed to reduce the direct $PM_{2.5}$ emissions from area-wide sources, such as motor vehicles and wood-burning stoves. Both of these conclusions are supported by the

Table 1. Summary of Chena Power Plant Boilers and Emission Rates

Boiler	Boiler Size (10^6 Btu/hr)	Installation Date	Average Airflow Rate (dscf/min[a,b])	Average Measured Emissions[a]					
				SO_2			NOx		
				lb/hr[c]	ppm[d, e]	ton/yr[f]	lb/hr	ppm	ton/yr
Boiler No. 1 (travelling grate stoker equipped with over-fire air and air preheaters)	76	1954	141,610	189.4	134.3	829.6	177.0	174.0	775.3
Boiler No. 2 (travelling grate stoker equipped with over-fire air and air preheaters)	76	1952							
Boiler No. 3 (travelling grate stoker equipped with over-fire air and air preheaters)	76	1952							
Boiler No. 5 (spreader stoker equipped with over-fire air, low excess air, and air preheaters)	269	1970							

a. Average measured airflow and emissions during November 2011 source test
b. dscf/min = dry standard cubic feet per minute
c. lb/hr = pound per hour
d. ppm = parts per million
e. SO_2 ppm limit is 500 ppm
f. ton/yr = tons per year

analyses presented later in this BACT evaluation. The ADEC supported their conclusion that NOx control would be ineffective by including a stationary source precursor demonstration in the control evaluation. The ADEC conclusion was sound, but the U.S. EPA had not provided a recommended procedure or insignificant impact level prior to SIP development. As stated earlier, the U.S. EPA has now proposed to approve the precursor demonstration for NOx. ADEC did not prepare a precursor demonstration for SO_2.

1.7.2 *Estimates of Secondary Particulate Loads on $PM_{2.5}$ Filters*

The ADEC included background reports in the SIP that provided estimates of the various source contributions to ambient $PM_{2.5}$ concentrations. A chemical mass balance (CMB) technique was used by the University of Montana to estimate source contributions for each day that a filter was collected at several monitoring stations in the FNSB between 2005 and 2013.[8] Using two different source profiles, the report authors estimated the contributions due to secondary sulfates and nitrates, wood smoke, and various other sources in the FNSB. Looking at the CMB estimates for days that exceeded the standard at downtown Fairbanks monitors, one sees very high contributions from wood smoke (50 to 76 percent of the $PM_{2.5}$ mass using the EPA profile and 8 to 59 percent of the $PM_{2.5}$ mass using the OMNI profile), and in many cases at the State Building and Peger Road stations, the EPA profile yields estimates that $PM_{2.5}$ contributions from wood smoke alone exceeds the NAAQS. The contribution from ammonium nitrate was estimated to be small, ranging from 1.0 to 8.0 $\mu g/m^3$ and 0 to 5.8 $\mu g/m^3$ on days when the standard was exceeded in Fairbanks using the EPA and OMNI profiles, respectively. Similar patterns were observed at the North Pole monitoring stations.

The SIP also included a modeling evaluation of base year (2008) emissions and future year (2015 and 2019) emissions. The modeling evaluations for future years were run with and without the stationary source NOx emissions. This modeling evaluation became the basis for a stationary source precursor demonstration in the Moderate attainment plan and could become the basis for a State-developed comprehensive precursor or major stationary source demonstration in a Serious attainment plan. As stated earlier, this precursor demonstration indicates that stationary source NOx control is ineffective in the FNSB and has been proposed to be approved by the U.S. EPA.

1.7.3 Basin-wide Emission Inventory

As part of the SIP development process, the ADEC also prepared a basin-wide emission inventory of all point and area sources. Table 2 presents a reproduction of the 2008 Actual Emission Inventory for the FNSB $PM_{2.5}$ nonattainment area and the Grid 3 modeling domain during 35 episode days. (For the Fairbanks SIP, modeling inventories were developed over a gridded modeling domain called "Grid 3," which encompasses an area of 201 × 201 grid cells, each 1.33 km square. The domain encompasses portions of four counties/boroughs: Fairbanks North Star, Denali, Southeast Fairbanks, and Yukon-Koyukuk.) The emissions are presented in units of (average) tons per day (ton/day) because the $PM_{2.5}$ NAAQS is a 24-hour standard. This is consistent with the U.S. EPA's final $PM_{2.5}$ rule that allows use of "episodic" averaging periods when evaluating

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[8] The Fairbanks, Alaska $PM_{2.5}$ Source Apportionment Research Study Winters 2005/2006-2012/2013, and Summer 2012; Final Report, Amendments 6 and 7, December 23, 2013, Tony J. Ward, Ph.D., University of Montana – Missoula , Center for Environmental Health Sciences.

contributors to ambient $PM_{2.5}$ concentrations. This approach could help to ensure the nonattainment area inventory reflects the emissions conditions that led to an initial nonattainment area designation.[9]

For comparison to the SIP inventory presented in Table 2, the Chena Power Plant has "typical" emissions of 1.9 and 1.8 ton/day of SO_2 and NOx, respectively, which represent about 14.8% and 7.6% of the area daily SO_2 and NOx emissions, respectively. These typical Chena emission rates were based on the average coal consumed in 2015 on days when the $PM_{2.5}$ standard was exceeded. Use of 2015 Chena data to compare to the 2008 baseline is warranted as ADEC assumed 2008 emissions would hold constant through 2015 due to uncertainty of activity growth and fuel switching for specific facilities.[10]

Table 2. 2008 Baseline Episode Average Daily Emissions (ton/day) by Source Sector, Actual Point Source Emissions[11]

Source Sector	Grid 3 Domain Emissions (ton/day)					NA Area Emissions (ton/day)				
	$PM_{2.5}$	SO_2	NOx	VOC	NH_3	$PM_{2.5}$	SO_2	NOx	VOC	NH_3
Point (Actual)	1.526[12]	8.380	13.395	0.096	n/a	1.412	8.167	13.285	0.096	n/a
Area, Space Heating	3.098	4.286	2.391	12.369	0.149	2.756	3.865	2.182	11.058	0.136
Area, Space Heat, Wood	2.986	0.095	0.421	12.207	0.110	2.656	0.084	0.373	10.914	0.098
Area, Space Heat, Oil	0.062	4.121	1.774	0.098	0.003	0.056	3.719	1.617	0.088	0.003
Area, Space Heat, Other	0.050	0.070	0.196	0.065	0.037	0.043	0.062	0.192	0.056	0.035
Area, Other	0.064	0.000	0.003	0.692	0.000	0.061	0.000	0.002	0.569	0.000
On-Road	0.811	0.057	5.743	7.439	0.088	0.676	0.046	4.625	5.725	0.071
On-Road, Running Exh	0.503	0.050	4.322	0.941	0.088	0.435	0.040	3.561	0.765	0.071
On-Road, Start & Idle Exh	0.308	0.008	1.421	6.410	0.000	0.242	0.006	1.064	4.894	0.000
On-Road, Evap	0.000	0.000	0.000	0.088	0.000	0.000	0.000	0.000	0.066	0.000
Non-Road	0.238	0.151	2.135	12.262	0.005	0.027	0.077	1.088	0.451	0.003
TOTALS	**5.736**	**12.875**	**23.667**	**32.859**	**0.242**	**4.932**	**12.155**	**21.182**	**17.898**	**0.210**

n/a = not available.

[9] Federal Register, Volume 81, pages 58031, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

[10] ADEC, Amendments to: State Air Quality Control Plan, Volume II: Analysis of Problems, Control Actions; Section III: Area-wide Pollutant Control Program; D: Particulate Matter; 5: Fairbanks North Star Borough $PM_{2.5}$ Control Plan, Section 5.06, page III.D.5.6-43

[11] ADEC, Amendments to: State Air Quality Control Plan Volume II: Analysis of Problems, Control Actions; Section III: Area-wide Pollutant Control Program; D: Particulate Matter; 5: Fairbanks North Star Borough $PM_{2.5}$ Control Plan, Section 5.06, page III.D.5.6-27.

[12] Docket Document 105_Clarification 11.3.16, https://www.regulations.gov/document?D=EPA-R10-OAR-2015-0131-0016

2 DISCUSSION OF NOx CONTROL OPTIONS

NOx emissions from combustion sources consist primarily of two types: thermal NOx and fuel-related NOx. Thermal NOx is formed by the high temperature reaction of nitrogen and oxygen during combustion. The amount of NOx formed is a function of the combustion chamber design and the combustion source operating parameters, including flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios in the primary combustion zone. Fuel NOx is formed by the gas phase oxidation of fuel-bound nitrogen. Fuel NOx formation is largely independent of combustion temperature and the nature of the organic nitrogen compound present in the fossil fuel. Its formation is dependent on fuel nitrogen content and combustion oxygen levels.

The coal burned in the Chena boilers is Usibelli, sub-bituminous coal with 0.39 to 0.59 weight percent fuel-bound nitrogen. Therefore, NOx emissions likely consist of both thermal and fuel-NOx. The combined NOx emission rate from the four Chena boilers is 0.36 lb/MMBtu, which is achieved through the use of the existing combustion controls. According to U.S. EPA, the baseline NOx emission rate for sub-bituminous coal-fired boilers is 0.50 lb/MMBtu.[13]

Control options for NOx fall into two categories: add-on controls and combustion controls. Add-on controls involve chemical reactions with NOx in the combustion gas to convert the NOx to nitrogen. The common technologies include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Both of these technologies require introduction of ammonia or urea into the gas stream. The primary difference between the two technologies is that SCR has a much higher capital cost and can be performed at a lower temperature than SNCR. Combustion controls consist of techniques to reduce the peak combustion temperature, and therefore the thermal NOx formation. These techniques include use of low-NOx burners (LNB), flue gas recirculation (FGR), natural gas reburning (NGR), over-fire air (OFA), lean excess air (LEA), water or steam injection, staged combustion, and combustion optimization.

[13] New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

2.1 REVIEW OF NOx BACT DATABASE

Typically, databases maintained by U.S. EPA and the ADEC are reviewed to obtain a summary of previous BACT analyses. These reviews allow an applicant to identify control technologies in use at other similar facilities. The database review is then followed by a site-specific review of the emission reduction technique(s) to be incorporated into the proposed project. The requirements identified in 18 AAC 50, Article 3 must be considered when performing a BACT analysis.

Databases are maintained by U.S. EPA and the ADEC that provide summaries of previous control technology determinations related to RACT, BACT, and LAER. The U.S. EPA database is referred to as the RACT/BACT/LAER Clearinghouse ('the Clearinghouse"). The Clearinghouse was reviewed for data pertaining to NOx emission control methods for coal-fired boilers with heat input capacity greater than 250 MMBtu/hr and less than 100 MMBtu/hr.

The Clearinghouse lists four facilities (seven sources) with coal-fired boilers greater than 250 MMBtu/hr and BACT NOx emission limits imposed within the last 5 years. Table 3 summarizes the projects in the database search that are pertinent to the BACT evaluation for the Aurora project. BACT for two of the sources was determined to be SNCR in combination with combustion modifications (e.g., staged combustion). BACT for the other five sources identified in the database query was determined to be combustion modifications (e.g., LNB, OFA], staged combustion, and/or good combustion practices). It should be noted that all the sources identified in the search are much larger than the largest Chena Power Plant boiler. Also, the units identified in the BACT database are new and did not require retrofitting considerations. No BACT records were identified in the search for small boilers less than 100 MMBtu/hr capacity.

A review of the ADEC permit database identified eight Title I construction permits issued within the last 5 years. However, none of these permits were issued to facilities with coal-burning emission units. The University of Alaska Fairbanks Campus obtained a minor permit in October 2016 for a coal-fired boiler replacement project; however, the University obtained Owner Requested Limits to avoid PSD and the requirement to perform a BACT evaluation.

Table 3. Summary of NOx BACT Permit Reviews

Search Criteria	Facility ID	Facility Name	Emission Unit	Permit Date	NOx Limit	Control Required	Comment
Permit Date = 1/1/2011 to 1/1/2016 Process = coal-fired, >250 MMBtu/hr Pollutant Name = NOx	OK-0152	O G and E – Muskogee Generating Station	Coal-fired Boiler (550 MW = 1,880 MMBtu/hr)	01/30/2013	0.15 lb/MMBtu (BART)	Low-NOx burners (LNB) and overfire air (OFA) (30% reduction)	
	OK-0151	O G and E – Sooner Generating Station	Coal-fired Boiler (550 MW = 1,880 MMBtu/hr)	01/17/2013	0.15 lb/MMBtu (BART)	LNB and OFA	
	ND-0026	Minnkota Power Cooperative - M.R. Young Station	Cyclone Boilers, Unit 1 (3,200 MMBtu/hr)	03/08/2012	0.36 lb/MMBtu (BACT-PSD)	Low bed temperature staged combustion; SNCR (58% reduction)	Lignite coal. The BACT determination was required as part of a Consent Decree for alleged PSD violations.
			Cyclone Boilers, Unit 2 (6,300 MMBtu/hr)		0.35 lb/MMBtu (BACT-PSD)		
	AZ-0055	Salt River Project Agricultural and Power District – Navajo Generating Station	Three pulverized coal boilers, each 7,725 MMBtu/hr	02/06/2012	0.24 lb/MMBtu (BACT-PSD)	LNB and OFA	Permit issued on 11/20/2008 and administratively amended on 2/6/2012. Affected Class I areas can be found in BART regulatory docket.
Permit Date = 1/1/2011 to 1/1/2016 Process = coal-fired, <100 MMBtu/hr Pollutant Name = NOx	No search results.						

2.2 IDENTIFICATION OF NOx CONTROL OPTIONS

NOx control options generally consist of the following types:

- Combustion Controls
  - fuel switching
  - LNB and other combustion controls
  - steam/water injection
  - natural gas reburn
- Post-Combustion Controls
  - SNCR
  - SCR
  - Non-Selective Catalytic Reduction (NSCR)

2.3 TECHNICALLY INFEASIBLE NOx CONTROL OPTIONS

2.3.1 Alternate Fuel

This evaluation considers retrofit of existing coal-fired equipment. It is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible.

2.3.2 Combustion Control

All four of the boilers are stokers, which means the coal combusts on a grate and the boilers do not have burners. Therefore, LNB is not an option. However, Chena Power Plant Unit 5 is equipped with OFA, LEA (i.e., oxygen trim system), and air preheaters. Units 1, 2, and 3 have OFA and air preheaters. An oxygen trim system is not available for these traveling grate boilers. These combustion controls are conservatively expected to achieve a 30 to 50 percent reduction in NOx emissions.

2.3.3 Steam and Water Injection

Steam/water injection into the combustion zone to reduce the firing temperature has been traditionally associated with minimizing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Therefore, steam/water injection is considered technically infeasible.

2.3.4 *Reburn*

Reburn was developed as a NOx combustion control technique primarily for use on coal-fired furnaces, which involves splitting the combustion zone by installing a second level of burners above the primary combustion zone. Most installations employing reburn for NOx control have used natural gas as the reburn fuel; however, reburn combustion control requires significant changes to the design of the furnace and the additional operating expense of the reburn fuel. In essence, reburn is not a retrofit technology. Therefore, reburn is considered technically infeasible.

2.3.5 *Non-Selective Catalytic Reduction*

NSCR is an add-on NOx control technology that uses a catalyst reaction to simultaneously reduce NOx, CO, and hydrocarbon (HC) to water, carbon dioxide, and nitrogen. NSCR is generally used for internal combustion engines rather than industrial boilers. Therefore, NSCR is considered technically infeasible.

2.4 *TECHNICALLY FEASIBLE NOx CONTROL OPTIONS*

Because all technically feasible combustion control methods have already been employed to reduce emissions, the only remaining potential NOx control for the Chena Power Plant units would entail use of SCR or SNCR.

2.4.1 *Selective Catalytic Reduction*

SCR is a post-combustion control technology in which ammonia is introduced into the exhaust gas from a boiler to react with NOx in the presence of a catalyst to form water and nitrogen. The active surface of the catalyst is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Most SCR systems operate in the 500 to 800 degrees Fahrenheit temperature range. An ammonia injection grid is located upstream of the catalyst body and designed to disperse ammonia throughout the exhaust flow before entering the catalyst unit. Exhaust gas temperature dramatically affects NOx reduction, because the catalyst exhibits optimum performance within a narrow temperature range. Below this optimum temperature range, the catalyst activity is greatly reduced, allowing unreacted ammonia to "slip" through the catalyst bed and out of the exhaust stack. This slip results in increased ammonia concentration in the exhaust gas that is discharged into the atmosphere. Above the optimal temperature range, ammonia begins to be oxidized to form additional NOx. In addition, operation of the equipment above the optimal temperature range for an extended period of time accelerates the catalyst-poisoning rate, which requires early replacement of the catalyst. Thus, the use of the SCR process requires tight operating temperature controls plus continual adjustment of the ammonia injection rate to match the rate of NOx formation.

Use of SCR in a high-sulfur environment presents some technical complications. Exposing a catalyst to sulfur-bearing fuels and ammonia forms ammonium sulfate (an ammonium salt that is a source of $PM_{2.5}$). These salts foul the surface of the catalyst, rendering the catalyst useless and necessitating premature replacement. Sulfur-tolerant SCR catalysts are available, but are composed of vanadium pentoxide (V_2O_5), a hazardous substance. These catalysts (V_2O_5) are still susceptible to some ammonium sulfate fouling. The spent V_2O_5 catalyst would have to be shipped off-site for disposal. To address this concern, many catalyst vendors operate exchange programs where spent catalysts are exchanged for new catalysts at a reduced price. Exchange programs alleviate customer waste disposal concerns and allow the vendor to recycle the precious metals that compose many of the catalysts.

Carefully designed SCR systems can achieve NOx emission rates of 0.1 lb NOx/MMBtu (i.e., 80 percent reduction from the baseline of 0.5 lb/MMBtu or 72 percent reduction from the current Chena NOx emission rate of 0.36 lb/MMBtu), with vendor guarantees of no greater than 10 ppm ammonia slip available.[14]

2.4.2 *Selective Non-Catalytic Reduction*

SNCR is a post-combustion control technology in which either ammonia or urea is injected into the firebox of a boiler at a location where the flue gas is between 1,600 and 2,100 degrees Fahrenheit to react with the NOx formed in the combustion process. NOx reduction levels range from 30 to 50 percent. The resulting product of the chemical reaction is molecular nitrogen, carbon dioxide, and water. Units with furnace exit temperatures of 1,550 to 1,950 degrees Fahrenheit, residence times greater than one second, and high levels of uncontrolled NOx (e.g., 200 to 400 ppm) are good candidates for SNCR. NOx concentrations in the Chena combined exhaust are barely at a level that would make use of SNCR technically feasible, in that the average NOx concentration is less than 200 ppm.

[14] Achieving NOx Compliance at Least Cost: A Guideline for Selecting the Optimum Combination of NOx Controls for Coal-Fired Boilers, TR-111262, December 1998, EPRI

SNCR systems can achieve NOx emission rates of 0.25 lb NOx/MMBtu (i.e., 50 percent reduction from the baseline of 0.5 lb NOx/MMBtu or 30 percent reduction from the current Chena Power Plant NOx emission rate of 0.36 lb NOx/MMBtu), but a lesser efficiency would be expected at Chena Power Plant due to the low NOx concentration. Thus, use of this technology is only marginally technically feasible.

Urea-based systems have advantages over ammonia-based systems. Ammonia slip may cause formation of ammonium sulfates, which can plug or corrode downstream equipment (i.e., the baghouse), cause ammonia absorption into fly ash, affecting disposal or reuse, and increase $PM_{2.5}$ emissions. Conversely, urea is a non-toxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing. However, urea is more expensive than ammonia. In addition, a urea solution stored in the cold Fairbanks climate would need to be heated to prevent crystallization.

Additional costs for SNCR retrofit can be 10 to 30 percent of the SNCR system cost. In general, SNCR retrofit of large and medium size boilers is relatively simple; however, the difficulty significantly increases for smaller boilers, such as those at Chena Power Plant where there is limited wall space for installation of the injectors. Movement and/or removal of existing equipment and asbestos also may be required. In addition, adequate space adjacent to the boiler must be available for distribution system equipment and for maintenance.

2.4.3 Effectiveness of Technically Feasible NOx Control Options

Table 4 presents the technically feasible NOx control options and ranks them by control effectiveness. Table 5 presents the technically feasible NOx control options and ranks them by cost effectiveness. Based on the systems identified in the RBLC search, emission rates varied from 0.15 to 0.24 lb NOx/MMBtu with LNB and OFA to 0.36 lb/MMBtu with low bed temperature staged combustion and SNCR. The Chena Power Plant already achieves 0.36 lb NOx/MMBtu with the existing combustion controls.

Table 4. Control Effectiveness of NOx Control Options

Rank	Control Option	Emission Unit	Control Efficiency and Emission Rate Achieved
1	SCR	Chena Power Plant (combined exhaust)	80 percent control from baseline; 0.10 lb/MMBtu (i.e., 72 percent control of Chena's current NOx emission rate)
2	SNCR	Chena Power Plant, Units 1, 2, and 3	50 percent control from baseline; 0.25 lb/MMBtu (i.e., 30 percent control of Chena's current NOx emission rate)
		Chena Power Plant, Unit 5	
3	Combustion controls	Chena Power Plant, Units 1, 2, 3, and 5	0.36 lb/MMBtu

Table 5. Cost Effectiveness of NOx Control Options

Rank	Control Option	Emission Unit	Cost Effectiveness, $/ton
1	SCR	Chena Power Plant (combined exhaust)	28,347
2	SNCR	Chena Power Plant, Units 1, 2, and 3	7,649 (each boiler)
		Chena Power Plant, Unit 5	12,059
3	Combustion controls	Chena Power Plant, Units 1, 2, 3, and 5	-- (already installed)

2.4.4 *Economic Evaluation of NOx Control Options*

Capital costs associated with the installation of a SCR system or SNCR systems are based on cost estimating procedures developed by U.S. EPA. Total capital investment costs were estimated as if the project would be constructed in the lower 48 U.S. states and then corrected using two correction factors taken from the Department of Defense Unit Cost/Area Cost Factors and Facilities Pricing Guide UFC 3-730-01. The first correction factor is a site-specific Location Adjustment Factor (LAF) of 2.2 for Fairbanks, Alaska. The second factor, the Site Sensitivity Factor (SSF) of 1.101, was calculated using an equation that accounts for labor availability (slightly below normal, +0.041), housing availability (slightly below normal, +0.022), material availability (slightly below normal, +0.01), and a +0.028 factor for a congested work area. The LAF and SSF were also applied to material costs in the calculation of annualized costs to reflect the added expense of transporting materials to the Chena Power Plant. Additionally, a retrofit factor of 30 percent has been added to the cost estimate, but this factor is likely low. The cost summaries indicate the extent to which these factors have been applied.

Cost-effectiveness of each NOx control system was calculated in a conventional BACT manner by dividing the total annual cost by the annual tons of pollutant removed. Annual costs also were divided by daily tons of pollutant removed. Costs were converted to 2015 dollars using the Chemical Engineering Composite Price Index. All indices used are noted. The following tables present summaries of capital and annualized costs:

- Table 6 - Capital Cost Summary: SCR for Combined Chena Exhaust
- Table 7 - Annualized Cost Summary: SCR for Combined Chena Exhaust
- Table 8 - Capital Cost Summary: SNCR for 76 MMBtu/hr Boiler
- Table 9 - Capital Cost Summary: SNCR for 269 MMBtu/hr Boiler
- Table 10 - Annualized Cost Summary: SNCR for 76 MMBtu/hr Boiler
- Table 11 - Annualized Cost Summary: SNCR for 269 MMBtu/hr Boiler
- Table 12 - Summary of Overall Annualized Costs for SNCR

Table 6. Capital Cost Summary: SCR for Combined Chena Exhaust

Capital costs were estimated using equations from the EPA document "Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-fired Boilers" (EPA/600/R-01/087, October 2001). These equations estimate retrofit costs in CY2000 dollars. Therefore, all costs were corrected to 2015 dollars using the Composite CE Price Index.	
A = plant capacity (kW) = (H x 10^6 x G x 0.00029 kW/Btu/hr / conv. eff.) =	192,173
B = NOx (lb/10^6 Btu) at the inlet of SCR reactor =	0.36
C = NOx removal efficiency (percent) =	72
G = annual capacity factor (expressed as a fraction) =	0.8
H = heat input (10^6 Btu/hr) =	497
assumed boiler conversion efficiency	0.6
Composite CE Index for 2000 (cost year of equation)	394.1
Composite CE Index for 2015 (cost year of review)	578.4
Capital cost (D) = 75 {300,000 [(B/1.5)$^{0.05}$ (C/100)$^{0.4}$]/A}$^{0.35}$ [CEI(2015)/CEI(2000)]	
D = capital cost ($/kW) =	120
Item	**Cost ($)**
<u>DIRECT COSTS</u>	
DIRECT CAPITAL COSTS (includes equipment, installation, engineering, contingency, spare parts, and commissioning)[a] (A x D)	23,028,006
Taxes (0.05 x Direct Capital Cost)	1,151,400
Freight (0.05 x Direct Capital Cost)	1,151,400
TOTAL DIRECT COSTS	**25,330,806**
<u>INDIRECT COSTS</u>	
Construction management (10% of total purchased equipment costs)	2,302,801
Construction fee (10% of total purchased equipment costs)	2,302,801
Performance test (1% of total purchased equipment costs)	230,280
TOTAL INDIRECT COSTS	**4,835,881**
TOTAL CAPITAL COST	**30,166,687**
CORRECTED TOTAL CAPITAL COST (notes c and d)	**73,069,750**
a. Capital costs were estimated using equations from the EPA document "Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-fired Boilers" (EPA/600/R-01/087, October 2001).	
b. Cost methodology based on "Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems", by PEDCo Environmental, Inc., March 1983 (Ohio EPA Engineering Guide #46) unless otherwise specified.	
c. LAF = 2.2 Location Adjustment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\/2/, UFC 3-701-01, Change 8, July 2015.	
d. SSF = 1.101 Site Sensitivity Factor (related to limited labor and housing, limited material availability, and congested work area) from Programming Cost Estimates for Military Construction, UFC3-370-01, 6 June 2011.	

Table 7. Annualized Cost Summary: SCR for Combined Chena Exhaust

A = plant capacity (kW) = (H x 10^6 x G x 0.00029kW/Btu/hr / conv. eff.) =	192,173
B = NOx (lb/10^6 Btu) at the inlet of SCR reactor =	0.36
C = NOx removal efficiency (percent) =	72
D = capital cost ($/kW) =	120
G = annual capacity factor (expressed as a fraction) =	0.8
H = heat input (10^6 Btu/hr) =	497
assumed boiler conversion efficiency	0.6
Anhydrous NH_3 cost ($/ton [year 2000 $]) =	225
Composite CE Index for 2000 (cost year of equation)	394.1
Composite CE Index for 2015 (cost year of review)	578.4
1.005 = design margin that accounts for NH3 slip (see the appendix)	
1.05 = design margin that accounts for small amount of NO2 in flue gas (SCR chemistry requires 2 moles of NH3 per mole of NO2 instead of 1 mole of NH3 per 1 mole of NO)	
0.025 = catalyst deactivation factor for coal-fired units (yr-1)	
2.12 = a constant ($/kW-yr) = 0.03 (cost of energy in Yr 2000 $/kWh) * CEI(2015)/CEI(2000) * 8760 (h/yr) * 0.0055 (fraction cost of auxiliary power/unit of generation)	
Item	**Cost ($)**
DIRECT ANNUAL COSTS	
FIXED OPERATION AND MAINTENANCE (E) (includes annual maintenance material and labor cost)[a]	
E = [D x LAF x SSF] x A x 0.0066/yr	368,138
VARIABLE OPERATION AND MAINTENANCE	
Ammonia[a]	58,199
NH_3 use cost ($/yr) = G x (Anh. NH_3 Cost, [Yr 2000 $/ton]) x CEI(2015)/CEI(2000) x (0.37B x H x C/100 x 8760/2000) x 1.005 x 1.05	
Annual Catalyst Replacement[a]	91,084
Annual catalyst replacement cost ($/yr) = G x 0.025 x [D x LAF x SSF] x A x $[(B/1.5)^{0.05} (C/100)^{0.4}]$	
Electricity [a]	326,132
Energy requirement cost ($/yr) = G * 2.12 * A	
Ammonia Risk Management Professional (1040 hr/yr @ $40/hr)	41,600
TOTAL DIRECT ANNUAL OPERATING COSTS	**885,152**
INDIRECT ANNUAL COSTS	
Overhead (80% of total operation and maintenance labor)	294,510
Administrative charges (2% of total capital investment)	1,461,395
Insurance (1% of total capital investment)	730,698
Property tax (1% of total capital investment)	730,698
Capital recovery (16.275% of total capital investment: 10 yr at 10% interest)	11,892,102
TOTAL INDIRECT ANNUAL OPERATING COSTS	**15,109,402**
TOTAL ANNUALIZED OPERATING COSTS	**15,994,554**
TOTAL UNCONTROLLED NO_x EMISSIONS, tons	784
NO_x REMOVAL EFFICIENCY, %	72%
TOTAL NO_x REMOVED, tons	564
NO_x COST-EFFECTIVENESS, $/ton removed	**28,347**

Table 8. Capital Cost Summary: SNCR for 76 MMBtu/hr Boiler

Capital costs were estimated using equations from the EPA document "EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition" (EPA/452/B-02-001, January 2002).	
These equations estimate costs in CY1998 dollars. Therefore, all costs were corrected to 2015 dollars using the Composite CE Price Index.	
$Direct\ Capital\ Cost\ (D)(\$) = \frac{\$950}{MMBtu}\ Q_B\left(\frac{MMBtu}{hr}\right)\left[\frac{2375\ \frac{MMBtu}{hr}}{Q_B\left(\frac{MMBtu}{hr}\right)}\right]^{0.577}(0.66+0.85\eta_{NOx})\left(\frac{CE_{2016}}{CE_{equation}}\right)$	
Q_B = Boiler size (MMBtu/hr)	76
η_{NOx} = NOx removal efficiency	0.30
Composite CE Index for 1998 (cost year of equation)	389.5
Composite CE Index for 2015 (cost year of review)	578.4
Retrofit Factor	30%
Item	**Cost ($)**
DIRECT COSTS	
Direct Capital Cost (includes urea-based SNCR equipment, instrumentation, sales tax, freight, field measurements, numerical modeling, system design; installation of auxiliary equipment (e.g., ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation, and painting; and asbestos removal)[a]	714,838
Additional Retrofit Cost (10 to 30% of SNCR system cost)[b]	214,451
TOTAL DIRECT COSTS (A)	929,289
INDIRECT COSTS	
General Facilities (0.05 A) (Startup, Performance Test, and Model Study)	46,464
Construction/field expenses (0.20 A)	185,858
Construction Fee (0.10 A)	92,929
Engineering (0.10 A)	92,929
Process Contingency (0.05 A)	46,464
TOTAL INDIRECT COSTS (B)	464,645
Project Contingency (C = 0.15 x (A + B))	209,090
Total Plant Cost (D = A + B + C)	1,603,024
Allowance for Funds During Construction (E = 0, assumed for SNCR)	0
Royalty Allowance (F = 0, assumed for SNCR)	0
Preproduction Cost (G = 0.02 x (D + E))	32,060
Inventory Capital (H = $Vol_{reagent}$(gal) x $Cost_{reagent}$($0.85/gal), assume 2-week supply of 50% urea)	509
Initial Catalyst and Chemicals (I = 0, assumed for SNCR)	0
TOTAL CAPITAL COST (D + E + F + G + H + I)	**1,635,594**

a. EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition (EPA/452/B-02-001, January 2002)
b. Section 4.2, Chapter 1, Section 1.2.5 of the Cost Control Manual states that "Retrofit installation of the SNCR system generally calls for additional expenditures in the range of 10% to 30% of the SNCR system cost."

Table 9. Capital Cost Summary: SNCR for 269 MMBtu/hr Boiler

Capital costs were estimated using equations from the EPA document "EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition" (EPA/452/B-02-001, January 2002).	
These equations estimate costs in CY1998 dollars. Therefore, all costs were corrected to 2015 dollars using the Composite CE Price Index.	
$Direct\ Capital\ Cost\ (D)(\$) = \frac{\$950}{MMBtu}\ Q_B \left(\frac{MMBtu}{hr}\right)\left[\frac{2375\,\frac{MMBtu}{hr}}{Q_B\left(\frac{MMBtu}{hr}\right)}\right]^{0.577}(0.66 + 0.85\eta_{NOx})\left(\frac{CE_{2016}}{CE_{equation}}\right)$	
Q_B = Boiler size (MMBtu/hr)	269
η_{NOx} = NOx removal efficiency	0.30
Composite CE Index for 1998 (cost year of equation)	389.5
Composite CE Index for 2015 (cost year of review)	578.4
Retrofit Factor	30%
Item	**Cost ($)**
DIRECT COSTS	
Direct Capital Cost (includes urea-based SNCR equipment, instrumentation, sales tax, freight, field measurements, numerical modeling, system design; installation of auxiliary equipment (e.g., ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation, and painting; and asbestos removal)[a]	1,220,137
Additional Retrofit Cost (10 to 30% of SNCR system cost)[b]	366,041
TOTAL DIRECT COSTS (A)	1,586,178
INDIRECT COSTS	
General Facilities (0.05 A) (Startup, Performance Test, and Model Study)	79,309
Construction/field expenses (0.20 A)	317,236
Construction Fee (0.10 A)	158,618
Engineering (0.10 A)	158,618
Process Contingency (0.05 A)	79,309
TOTAL INDIRECT COSTS (B)	793,089
Project Contingency (C = 0.15 x (A + B))	356,890
Total Plant Cost (D = A + B + C)	2,736,158
Allowance for Funds During Construction (E = 0, assumed for SNCR)	0
Royalty Allowance (F = 0, assumed for SNCR)	0
Preproduction Cost (G = 0.02 x (D + E))	54,723
Inventory Capital (H = $Vol_{reagent}$(gal) x $Cost_{reagent}$($0.85/gal), assume 2-week supply of 50% urea)	1,803
Initial Catalyst and Chemicals (I = 0, assumed for SNCR)	0
TOTAL CAPITAL COST (D + E + F + G + H + I)	**2,792,684**
a. EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition (EPA/452/B-02-001, January 2002)	
b. Section 4.2, Chapter 1, Section 1.2.5 of the Cost Control Manual states that "Retrofit installation of the SNCR system generally calls for additional expenditures in the range of 10% to 30% of the SNCR system cost."	

Table 10. Annualized Cost Summary: SNCR for 76 MMBtu/hr Boiler

Q_B = Boiler size (MMBtu/hr)	76
η_{NOx} =NOx removal efficiency	0.30
NOx_{in} (lb/10^6 Btu)	0.44
NSR = Normalized Stoichiometric Ratio = $[(2 \times NOx_{in})+0.7] \times \eta_{NOx}/NOx_{in}$	1.08
Utilization = η_{NOx}/NSR	28%
$m_{reagent}$ (assume urea) (lb/hr) = $NOx_{in} \times Q_B \times \eta_{NOx} \times NSR \times 60.06$ g/mole/2 x 46.01 g/mole)	7.1
m_{sol} (50% solution) (lb/hr) = $m_{reagent}/0.5$	14.1
q_{sol} (gal/hr) = $m_{sol} \times 7.481$ gal/ft^3 / 71.0 lb/ft^3	1.49
$Cost_{reag}$ (50% urea solution) ($/gal)	0.85
t_{op} (SNCR operating time) (hr/yr) (80% capacity factor)	7,008
Power Consumption (P) (kW) = $0.47 \times NOx_{in} \times NSR \times Q_B / 9.5$)	1.78
$Cost_{elec}$ ($/kW)	0.21
Concentration of urea solution stored ($C_{urea\ sol\ stored}$)	50%
Concentration of urea solution injected ($C_{urea\ sol\ inj}$)	10%
Water to dilute urea (q_{water}) (gal/hr) = $m_{sol} / \rho_{water} \times (C_{urea\ sol\ stored}/C_{urea\ sol\ inj} - 1)$	6.76
$Cost_{water}$ ($/1,000 gal)	0.28
Heat of Vaporization (H_v) of water at 310 F (Btu/lb)	900
ΔCoal (MMBtu/hr) = $H_{water} \times m_{reagent} \times (1/C_{urea\ sol\ inj} -1) / 10^6$ Btu/MMBtu	0.06
$Cost_{coal}$ ($/MMBtu)	2.00
High Heating Value (HHV) of coal (Btu/lb)	7,500
wt% ash	10%
ΔAsh (ton/hr) = ΔCoal x 10^6 Btu/MMBtu x wt% ash / HHV / 2,000 lb/ton	0.0004
$Cost_{ash}$ ($/ton)	25

Item	**Cost ($)**
DIRECT ANNUAL COSTS	
Operating labor	
Operator labor ($63.13/hr x 4 man-hours/day, on-site data; EG46)	92,170
Supervision (15% of operator labor cost)	13,825
Maintenance (labor and material cost, including nozzle tip replacement for the injectors) (0.015 x TOTAL CAPITAL COST)	24,534
Reagent ($q_{sol} \times Cost_{reag} \times t_{op}$)	8,854
Electricity ($P \times Cost_{elec} \times t_{op}$)	2,623
Water ($q_{water}/1,000 \times Cost_{water} \times t_{op}$)	13
Coal (ΔCoal x $Cost_{coal} \times t_{op}$)	801
Ash (ΔAsh x $Cost_{ash} \times t_{op}$)	67
TOTAL DIRECT ANNUAL OPERATING COSTS	**142,887**
INDIRECT ANNUAL COSTS	
Overhead (80% of total operation and maintenance labor)	104,423
Insurance (1% of total capital investment)	16,356
Capital recovery (16.275% of total capital investment: 10 yr at 10% interest)	266,193
TOTAL INDIRECT ANNUAL OPERATING COSTS	**386,972**
TOTAL ANNUALIZED OPERATING COSTS	**529,859**

Table 11. Annualized Cost Summary: SNCR for 269 MMBtu/hr Boiler

Q_B = Boiler size (MMBtu/hr)	269
η_{NOx} =NOx removal efficiency	0.30
NOx_{in} (lb/10^6 Btu)	0.29
NSR = Normalized Stoichiometric Ratio = [(2 x NOx_{in})+0.7]x η_{NOx}/NOx_{in}	1.32
Utilization = η_{NOx}/NSR	23%
$m_{reagent}$ (assume urea) (lb/hr) = NOx_{in} x Q_B x η_{NOx} x NSR x 60.06 g/mole/2 x 46.01 g/mole)	20.2
m_{sol} (50% solution) (lb/hr) = $m_{reagent}$/0.5	40.5
q_{sol} (gal/hr) = m_{sol} x 7.481 gal/ft^3 / 71.0 lb/ft^3	4.26
$Cost_{reag}$ (50% urea solution) ($/gal)	0.85
t_{op} (SNCR operating time) (hr/yr) (80% capacity factor)	7,008
Power Consumption (P) (kW) = 0.47 x NOx_{in} x NSR x Q_B / 9.5)	5.11
$Cost_{elec}$ ($/kW)	0.21
Concentration of urea solution stored ($C_{urea\ sol\ stored}$)	50%
Concentration of urea solution injected ($C_{urea\ sol\ inj}$)	10%
Water to dilute urea (q_{water}) (gal/hr) = m_{sol} / ρ_{water} x ($C_{urea\ sol\ stored}$/$C_{urea\ sol\ inj}$ - 1)	19.39
$Cost_{water}$ ($/1,000 gal)	0.28
Heat of Vaporization (H_v) of water at 310 F (Btu/lb)	900
ΔCoal (MMBtu/hr) = H_{vwater} x $m_{reagent}$ x (1/$C_{urea\ sol\ inj}$ -1) / 10^6 Btu/MMBtu	0.16
$Cost_{coal}$ ($/MMBtu)	2.00
High Heating Value (HHV) of coal (Btu/lb)	7,500
wt% ash	10%
ΔAsh (ton/hr) = ΔCoal x 10^6 Btu/MMBtu x wt% ash / HHV / 2,000 lb/ton	0.0011
$Cost_{ash}$ ($/ton)	25

Item	Cost ($)
DIRECT ANNUAL COSTS	
Operating labor	
Operator labor ($63.13/hr x 4 man-hours/day, on-site wages; EG46)	92,170
Supervision (15% of operator labor cost)	13,825
Maintenance (labor and material cost, including nozzle tip replacement for the injectors) (0.015 x TOTAL CAPITAL COST)	41,890
Reagent (q_{sol} x $Cost_{reag}$ x t_{op})	25,389
Electricity (P x $Cost_{elec}$ x t_{op})	7,521
Water (q_{water}/1,000 x $Cost_{water}$ x t_{op})	38
Coal (ΔCoal x $Cost_{coal}$ x t_{op})	2,296
Ash (ΔAsh x $Cost_{ash}$ x t_{op})	191
TOTAL DIRECT ANNUAL OPERATING COSTS	**183,321**
INDIRECT ANNUAL COSTS	
Overhead (80% of total operation and maintenance labor)	118,308
Insurance (1% of total capital investment)	27,927
Capital recovery (16.275% of total capital investment: 10 yr at 10% interest)	454,509
TOTAL INDIRECT ANNUAL OPERATING COSTS	**600,745**
TOTAL ANNUALIZED OPERATING COSTS	**784,066**

Table 12. Summary of Overall Annualized Costs for SNCR

	1 Boiler @ 269 MMBtu/hr	3 Boilers @ 76 MMBtu/hr	Combined
Chena Power Plant Total Capacity, MMBtu/hr	269	228	497
Total Annualized Operating Costs, $	$784,066	$1,589,578	$2,373,645
Total Uncontrolled NOx Emissions, tons per year	342	439	781
NOx Removal Efficiency, %	30%	30%	30%
Total NOx Removed, tons per year	103	132	235
Average NOx removed, tons per day	0.28	0.36	0.64
Overall NOx Cost-Effectiveness, total $ per year/ton per year removed	**7,649**	**12,059**	**10,130**
Overall NOx Cost-Effectiveness, total $ per year/ton per day removed	**2,800,000**	**4,400,000**	**3,700,000**

3 DISCUSSION OF SO_2 CONTROL OPTIONS

SO_2 emissions are formed from the combustion of sulfur-containing fuels, such as coal, where the sulfur in the fuel is oxidized during the combustion process. The Usibelli, sub-bituminous coal burned in the Chena Power Plant boilers has a sulfur content ranging from 0.1 to 0.3 percent (ultimate analysis). The 500 ppm SO_2 allowable emission limit for the boilers is based on 0.4 percent sulfur content of the coal.

3.1 REVIEW OF SO_2 BACT DATABASE

The Clearinghouse lists two facilities (four sources) with coal-fired boilers and BACT SO_2 emission limits imposed within the last 5 years. Table 13 summarizes the projects in the database search that are pertinent to the BACT evaluation for the Chena Power Plant BACT evaluation.

It should be noted that all the sources identified in the search are much larger than the largest Chena Power Plant boiler. No BACT records were identified in the search for small boilers less than 100 MMBtu/hr capacity. Both sources identified in the database query specified wet flue gas desulfurization. One did not specify an emission limit; the second record specified a controlled emission rate of 1.2 lb SO_2/MMBtu.

The Chena Power Plant boilers burn low-sulfur Usibelli coal, and emissions from the combined stack have been measured to be 0.39 lb SO_2/MMBtu, one-third of the most recent BACT determination.

3.2 IDENTIFICATION OF SO_2 CONTROL OPTIONS

SO_2 control options generally consist of the following types:

- Pre-Combustion Controls
    - fuel substitution
- Post-Combustion Controls
    - wet scrubbers
    - dry scrubbers

Table 13. Summary of SO_2 BACT Permit Reviews

Search Criteria	Facility ID	Facility Name	Emission Unit	Permit Date	SO_2 Limit	Control Required	Comment
Permit Date = 1/1/2011 to 1/1/2016 Process = coal-fired, >250 MMBtu/hr Pollutant Name = SO2	AZ-0055	Salt River Project Agricultural and Power District – Navajo Generating Station	Three pulverized coal boilers, each 7,725 MMBtu/hr	02/06/2012	not specified	Flue Gas Desulfurization (FGD), Scrubber	Permit issued on 11/20/2008 and administratively amended on 2/6/2012. Affected Class I areas can be found in BART regulatory docket.
	TX-0601	Texas Municipal Power Agency Gibbons Creek Steam Electric Station	Boiler (5,060 MMBtu/hr)	10/28/2011	1.2 MMBtu/hr (BACT-PSD)	Wet FGD	
Permit Date = 1/1/2011 to 1/1/2016 Process = coal-fired, <100 MMBtu/hr Pollutant Name = SO2	No search results.						

Post combustion controls for flue gas desulfurization (FGD) are basically selected along the lines of coal sulfur levels; that is, dry systems are being selected for boilers that burn a low sulfur coal, and wet limestone forced oxidation (LSFO) systems are being selected for boilers that burn coals with 2 percent or greater sulfur levels.

3.3 TECHNICALLY INFEASIBLE SO_2 CONTROL OPTIONS

3.3.1 Fuel Substitution

This evaluation considers retrofit of existing coal-fired equipment. The Chena Power Plant boilers already use low-sulfur Usibelli coal with an average of 0.2 percent sulfur content, and switching to another coal source would not result in an appreciable reduction in SO_2 emissions. In addition, switching to fuel oil would not result in a reduction of SO_2 emissions, and adequate sources of natural gas are not readily available in Fairbanks to supply the Chena Power Plant with a reliable gas supply. Therefore, fuel substitution is considered technically infeasible.

3.3.2 Dry Scrubber

SO_2 control for the Chena Power Plant units could entail use of a FGD system. Most FGD systems employ two stages: one for fly ash removal and the other for SO_2 removal. In wet scrubbing systems, the flue gas first passes through a fly ash removal device, either an electrostatic precipitator or a baghouse, and then into the SO_2 absorber. However, in dry injection or spray drying operations, the SO_2 is first reacted with the sorbent, and then the flue gas passes through a PM control device. The combined exhaust from the Chena Power Plant is currently controlled by a common baghouse. Therefore, installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry injection or spray dry system. This would be cost-prohibitive; therefore, dry injection or spray drying operations are considered technically infeasible and only a wet FGD system is considered technically feasible for SO_2 control at the Chena Power Plant.

3.4 TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS

3.4.1 Wet Scrubber

In a wet scrubber system, flue gas is ducted to spray tower where an aqueous slurry of sorbent is injected into the gas. SO_2 dissolves into the slurry droplets where it reacts with the alkaline sorbent. The slurry is collected at the bottom of the spray tower, and treated flue gas is directed to a mist eliminator to remove any remaining slurry droplets. The spent slurry can either be recycled back to the absorber or dewatered and disposed. Typical sorbent materials are limestone (least expensive, least efficient), lime (more expensive, more efficient), or proprietary sorbents (most expensive, most efficient).

Some disadvantages of wet scrubbing techniques are (1) the cost of neutralizing chemicals, (2) disposal of the liquid stream containing soluble sulfur-containing salts, (3) scale build-up in the absorber, and (4) energy costs.

Limestone forced oxidation (LSFO) is a wet limestone scrubbing process that reduces the formation of gypsum scale in the absorber by oxidizing the spent slurry and removing the gypsum before it is recycled to the tower. The gypsum product can then be sold, thereby eliminating the disposal costs. However, limited markets exist for this gypsum product, and no viable outlets may actually be available for the gypsum.

Wet limestone scrubbing generally has high capital and operating costs due to the need to handle both liquid reagent and waste. As reported in a 2007 journal article, virtually no wet lime systems are currently being requested by the utility industry. As a result, FGD vendors are generally not offering wet lime systems.[15] In addition, moisture in the scrubber exhaust can result in a visible plume, which can become ice fog in the winter months in Fairbanks.

The SO_2 control efficiency currently achieved in practice by large coal utility units with wet FGD units ranges from 0.15 to 0.25 lb SO_2/MMBtu. This is in line with New Source Performance Standards, which require a SO_2 emission rate of 0.20 lb MMBtu or less. The Chena Power Plant currently emits 0.39 lb SO_2/MMBtu, which would require a 50 percent

[15] "Is It Time to Rethink SO_2 Control Technology Selection?" *Power Engineering*, November 1, 2007.

reduction in emissions to achieve an emission rate similar to other large coal-fired boilers.

3.4.2 *Effectiveness of Technically Feasible SO_2 Control Options*

Table 14 presents the technically feasible SO_2 control options and ranks them by control effectiveness. Table 15 presents the technically feasible SO_2 control options and ranks them by cost effectiveness.

Table 14. Control Effectiveness of SO_2 Control Options

Rank	Control Option	Emission Unit	Control Efficiency and Emission Rate Achieved
1	Wet Scrubber	Chena Power Plant (combined exhaust)	0.20 lb/MMBtu (i.e., 50 percent control of Chena's current SO_2 emission rate)
2	Low sulfur coal	Chena Power Plant (combined exhaust)	0.39 lb/MMBtu (already used)

Table 15. Cost Effectiveness of SO_2 Control Options

Rank	Control Option	Emission Unit	Cost Effectiveness
1	Wet Scrubber	Chena Power Plant (combined exhaust)	$74,146 per year/ ton per year removed
			$27,100,000 per year/ ton per day removed
2	Low sulfur coal	Chena Power Plant (combined exhaust)	-- (already used)

3.4.3 *Economic Evaluation of SO_2 Control Options*

Capital costs associated with the installation of a Wet Scrubber system are based on cost estimating procedures developed by U.S. EPA in the Coal Utility Environmental Cost (CUECost) tool. The CUECost tool is an Excel workbook (an interrelated set of spreadsheets) that produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control systems installed on coal-fired power plants, including those to control emissions of SO_2. The SO_2 emission control technologies currently in the workbook include: limestone FGD system with forced oxidation (i.e., wet scrubber) and lime spray drying FGD system (i.e., dry scrubber).

The wet scrubber portion of the CUECost tool was used and included the following site-specific information:

- Location
- Net Plant Heat Rate (Btu/kWhr) = 497 MMBtu/hr total heat input divided by 42 MW net output
- Retrofit Factor = 1.6 (1.0 = new, 1.3 = medium, 1.6 = difficult)
- Coal ultimate and proximate analysis data and ash analysis data obtained from http://www.usibelli.com/Coal-data.php
- Site specific SO_2 emission rate = 0.39 lb SO_2/MMBtu
- Cost Basis = 2015
- SO_2 Removal Required = 50 percent

All other values used were default values.

The cost-effectiveness of the SO_2 control system is calculated in the CUECost tool by dividing the total annual cost by the annual tons of pollutant removed. Cost-effectiveness also was calculated by dividing the total annual cost by the daily tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 16 presents a summary of the CUECost inputs and calculation summary for the wet scrubber, including the cost effectiveness of the technology. The ADEC performed a similar cost evaluation for coal boilers in Fairbanks. ADEC reported in the SIP that available cost information for wet scrubbers and spray dry systems indicate that these systems are not cost effective for units smaller than 500 MWe (Chena Power Plant combined heat input capacity is 150 MWe).

Appendix A presents the detailed CUECost output tables.

3.5 *SUMMARY OF COST EFFECTIVENESS OF CONTROL OPTIONS*

Cost effectiveness estimates are presented in Table 12 (for NOx control) and Table 15 (for SO_2 control). Although some question exists as to whether the control options are actually technically feasible, the cost effectiveness values exceed the amounts that could be considered cost effective. When looking at the costs on a ton per day removed basis (which is appropriate for control options designed to improve air quality compared to a 24-hr NAAQS), the cost effectiveness of NOx or SO_2 control options is seen to be tremendously high. Thus, implementation of any of these controls should be considered a huge economic burden and not cost effective means for bringing about $PM_{2.5}$ NAAQS attainment in the FNSB.

Table 16. CUECost Input and Calculation Summary: Wet Scrubber

CUECost Coal Utility Environmental Cost *Version 1, November 25, 1998 (revised 2-9-00 as CUECost3.xls)*		
INPUTS		
Description	**Units**	**Input 1**
General Plant Technical Inputs		
Location - State	Abbrev.	AK
MW Equivalent of Flue Gas to Control System	MW	150
Net Plant Heat Rate	Btu/kWhr	11833
Plant Capacity Factor	%	0.65
Total Air Downstream of Economizer	%	1.2
Air Heater Leakage	%	0.12
Air Heater Outlet Gas Temperature	°F	300
Inlet Air Temperature	°F	80
Ambient Absolute Pressure	in. of Hg	29.4
Pressure After Air Heater	in. of H2O	-12
Moisture in Air	lb/lb dry air	0.013
Ash Split:		
Fly Ash	%	0.8
Bottom Ash	%	0.2
Seismic Zone	Integer	1
Retrofit Factor	Integer	1.6
(1.0 = new, 1.3 = medium, 1.6 = difficult)		
Select Coal	Integer	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	No
Economic Inputs		
Cost Basis -Year Dollars	Year	2015
Sevice Life (levelization period)	Years	30
Inflation Rate	%	0.03
After Tax Discount Rate (current $'s)	%	0.092
AFDC Rate (current $'s)	%	0.108
First-year Carrying Charge (current $'s)	%	0.223
Levelized Carrying Charge (current $'s)	%	0.169
First-year Carrying Charge (constant $'s)	%	0.157
Levelized Carrying Charge (constant $'s)	%	0.117
Sales Tax	%	0.06
Escalation Rates:		
Consumables (O&M)	%	0.03
Capital Costs:		
Is Chem. Eng. Cost Index available?	Yes / No	Yes
If "Yes" input cost basis CE Plant Index.	Integer	578.4
If "No" input escalation rate.	%	0.03
Construction Labor Rate	$/hr	60
Prime Contractor's Markup	%	0.03
Operating Labor Rate	$/hr	63
Power Cost	Mills/kWh	25
Steam Cost	$/1000 lbs	3.5

Table 16. CUECost Input and Calculation Summary: Wet Scrubber (continued)

Limestone Forced Oxidation (LSFO) Inputs		
SO2 Removal Required	%	0.5
L/G Ratio	gal / 1000 acf	125
Design Scrubber with Dibasic Acid Addition?	Integer	2
(1 = yes, 2 = no)		
Adiabatic Saturation Temperature	°F	127
Reagent Feed Ratio	Factor	1.05
(Mole CaCO3 / Mole SO2 removed)		
Scrubber Slurry Solids Concentration	Wt. %	0.15
Stacking, Landfill, Wallboard	Integer	1
(1 = stacking, 2 = lanfill, 3 = wallboard)		
Number of Absorbers	Integer	1
(Max. Capacity = 700 MW per absorber)		
Absorber Material	Integer	1
(1 = alloy, 2 = RLCS)		
Absorber Pressure Drop	in. H2O	6
Reheat Required ?	Integer	1
(1 = yes, 2 = no)		
Amount of Reheat	°F	25
Reagent Bulk Storage	Days	60
Reagent Cost (delivered)	$/ton	15
Landfill Disposal Cost	$/ton	30
Stacking Disposal Cost	$/ton	6
Credit for Gypsum Byproduct	$/ton	2
Maintenance Factors by Area (% of Installed Cost)		
Reagent Feed	%	0.05
SO2 Removal	%	0.05
Flue Gas Handling	%	0.05
Waste / Byproduct	%	0.05
Support Equipment	%	0.05
Contingency by Area (% of Installed Cost)		
Reagent Feed	%	0.2
SO2 Removal	%	0.2
Flue Gas Handling	%	0.2
Waste / Byproduct	%	0.2
Support Equipment	%	0.2
General Facilities by Area (% of Installed Cost)		
Reagent Feed	%	0.1
SO2 Removal	%	0.1
Flue Gas Handling	%	0.1
Waste / Byproduct	%	0.1
Support Equipment	%	0.1
Engineering Fees by Area (% of Installed Cost)		
Reagent Feed	%	0.1
SO2 Removal	%	0.1
Flue Gas Handling	%	0.1
Waste / Byproduct	%	0.1
Support Equipment	%	0.1

Table 16. CUECost Input and Calculation Summary: Wet Scrubber (continued)

SUMMARY OF COSTS		
Description	**Units**	**Input 1**
SO2 Control Costs		LSFO
Total Capital Requirement (TCR)	$	$88,476,054
	$/kW	$589.84
First Year Costs		
Fixed O&M	$	$5,133,156
	$/kW-Yr	$34.22
	Mills/kWH	6.01
	$/ton SO2 removed	$18,604.0
Variable O&M	$	$621,703
	$/kW-Yr	$4.14
	Mills/kWH	0.73
	$/ton SO2 removed	$2,253.2
Fixed Charges	$	$19,730,160
	$/kW-Yr	$131.53
	Mills/kWH	23.10
	$/ton SO2 removed	$71,507.6
TOTAL	$	$25,485,020
	$/kW-Yr	$169.90
	Mills/kWH	29.84
	$/ton SO2 removed	$92,364.8
Levelized Current Dollars		
Fixed O&M	$/kW-Yr	$46.57
	Mills/kWH	8.18
	$/ton SO2 removed	$25,316.6
Variable O&M	$/kW-Yr	$5.64
	Mills/kWH	0.99
	$/ton SO2 removed	$3,066.2
Fixed Charges	$/kW-Yr	$99.68
	Mills/kWH	17.51
	$/ton SO2 removed	$54,191.9
TOTAL	$/kW-Yr	$151.89
	Mills/kWH	26.68
	$/ton SO2 removed	$82,574.7
Levelized Constant Dollars		
Fixed O&M	$/kW-Yr	$34.22
	Mills/kWH	6.01
	$/ton SO2 removed	$18,604.0
Variable O&M	$/kW-Yr	$4.14
	Mills/kWH	0.73
	$/ton SO2 removed	$2,253.2
Fixed Charges	$/kW-Yr	$69.01
	Mills/kWH	17.22
	$/ton SO2 removed	$53,289.1
TOTAL	$/kW-Yr	$107.38
	Mills/kWH	23.95
	$/ton SO2 removed	$74,146.3

4 DISCUSSION OF SITE-SPECIFIC CONSIDERATIONS

4.1 LOCATION LIMITATIONS

Several location limitations exist that could cause seemingly technically feasible emission reduction options to be only marginally feasible. Some of these location factors include:

- Plant congestion
- Transportation and ease of obtaining raw materials
- Climate

The BACT evaluation has included some consideration of the economic impact of congestion at the Chena Power Plant. An important aspect of operating on an older, small industrial site is the ability to actually place additional equipment needed to operate add-on control equipment. All of the identified feasible technologies require installation of tanks for reagent storage, and in some of the cases the technology itself must be erected in available space. The congested nature of the existing Chena Power Plant site is such that the retrofit installation costs are likely to be higher than those estimated and presented in the cost tables provided earlier. Additionally, lack of available space on site could make installation of additional equipment completely infeasible. The impact of site congestion is even more aggravated if multiple pollutant control technologies are selected. This limitation would not be completely understood prior to preliminary design of any identified system.

Each of the identified SO_2 and NOx technologies also requires routine delivery of reagents to operate the system, and the SO_2 technologies will require removal of residues produced by the process. Fairbanks is approximately 400 miles from Anchorage, which is a logical location for origination of raw materials. Delivery of hazardous liquids over potentially icy roadways may interrupt raw material deliveries to the point where interruptions in plant operations could occur. The hazardous driving conditions also may cause the transportation costs for raw materials or process equipment to be greater than presented in the cost sheets, thereby causing the cost effectiveness of control to be a larger value than calculated.

Climate considerations factor into the BACT evaluation in two ways: 1) climate causes the costs to become inflated due to the need for additional insulation, heated vessels, and heat tracing, and 2) climate affects the ability of the precursor emissions from the Chena Power Plant to react in the atmosphere and form $PM_{2.5}$. The first factor is partially considered in the NOx control cost calculation in that a SSF and LAF are included in the cost estimate. However, no site factors are included in the SO_2 control cost calculations. Thus, the SO_2 control costs, while already extremely high, are underestimated. The atmospheric factor, which may limit atmospheric reaction rates, is briefly discussed in the next section on environmental considerations.

4.2 ENVIRONMENTAL AND ENERGY CONSIDERATIONS

Environmental and energy considerations must be considered in a BACT evaluation. With respect to nonattainment BACT, precursor control options that are determined to be economically feasible may not yield the desired objective of improving $PM_{2.5}$ air quality. (This statement is true even though none of the control options evaluated in this BACT evaluation were found to be economically feasible.) A rash conclusion to implement a (economically feasible) precursor control as BACT may in fact produce insignificant environmental benefits and at the same time produce adverse energy or environmental impacts. These topics are discussed below.

4.2.1 Environmental Considerations

The rationale for ensuring that benefits of a precursor control option are indeed real and significant is founded in the CAA. CAA section 189(e) explicitly requires that the control requirements applicable for major stationary sources of direct $PM_{2.5}$ emissions must also apply to major stationary sources of $PM_{2.5}$ precursors, unless the state provides a demonstration that emissions of a particular precursor from major stationary sources do not contribute significantly to levels that exceed the standard in the nonattainment area of concern. Thus, the statute generally requires control of all $PM_{2.5}$ precursors in a nonattainment area, but it provides an express exception applicable to major stationary sources in such areas if an appropriate demonstration is made.[16]

A key conclusion derived by looking at the CMB evaluations for PM filters collected in the FNSB is that control of Chena Power Plant $PM_{2.5}$ precursors will not provide significant reduction of ambient $PM_{2.5}$. This

[16] Federal Register, Volume 81, page 58091, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

conclusion can easily be validated by looking solely at the wood smoke contribution and comparing it to the $PM_{2.5}$ standard. As is seen on many episode days, the standard is exceeded solely due to contribution from wood smoke, while the impact of nitrates on episode days is minor. The contribution of sulfates also is minor. A demonstration of this occurrence, was included in the Moderate SIP submittal as part of a precursor demonstration. U.S. EPA subsequently proposed to approve the Moderate plan precursor demonstration.[17]

Various procedures can be used to determine a specific source contribution to ambient $PM_{2.5}$ concentrations and, by extension, the air quality improvements in $PM_{2.5}$ air quality should one or more control measures be implemented at the Chena Power Plant. Because no one procedure answers every question one may have, a variety of procedures are often employed. This is a key issue that relates the magnitude of reductions in daily precursor emissions to commensurate reductions in $PM_{2.5}$ concentrations. In many cases, indirect procedures must be employed to estimate air quality benefits resulting from installation of precursor emission controls. For example, SNCR (the NOx control option identified herein that has the best cost-effectiveness) was estimated to be able to achieve a 30 percent reduction in NOx emissions from the Chena Power Plant boilers, and the most cost-effective SO_2 control option identified herein can achieve a 50 percent reduction in SO_2 emissions from the boilers. As introduced earlier in Section 1.7.3, on average, Chena Power Plant boilers emitted 1.8 and 1.9 ton/day of NOx and SO_2, respectively, in 2015 on days when the $PM_{2.5}$ standard was exceeded. Thus, application of NOx and/or SO_2 controls at Chena Power Plant would result in an average NOx reduction of 0.54 ton/day and an average SO_2 reduction of 0.95 ton/day. These reductions represent only 2.6 percent and 7.8 percent of the estimated NOx and SO_2 nonattainment area-wide emissions, respectively, estimated to occur on $PM_{2.5}$ episode days in 2008 (see Table 2, presented previously).

ADEC included CMB results in the SIP to provide some insight into establishing source contributions in the FNSB. As discussed in Section 1.7.2, the CMB analysis employed during SIP development estimates that ammonium nitrate contributed a maximum of 8 $\mu g/m^3$ (at most) to the $PM_{2.5}$ mass on filters collected in downtown Fairbanks on high $PM_{2.5}$ concentration days between 2005 and 2013. (Appendix III.D.5.7 of the SIP

[17] Federal Register, Volume 82, February 2, 2017, 40 CFR Part 52, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

reports that "nitrates comprise about 4% of the measured $PM_{2.5}$ concentrations in Fairbanks. This corresponds to a hydrated ammonium nitrate concentration of 3.4 $\mu g/m^3$.")[18] The CMB analysis also estimates a maximum sulfate contribution of 28.8 $\mu g/m^3$ (at most) over the same time period. Assuming that all of the precursor emission reductions noted above for Chena Power Plant culminate in the same level of ambient $PM_{2.5}$ reductions, the identified NOx and SO_2 control technologies would benefit ambient air quality in downtown Fairbanks by only 0.2 $\mu g/m^3$ for nitrates (i.e., 8.0 μg nitrate/m^3 times 2.6 percent reduction in daily NOx emissions) and only 2.2 $\mu g/m^3$ for sulfates (i.e., 28.8 μg sulfate/m^3 times 7.8 percent reduction in daily SO_2 emissions). The improvements on an average basis would be about half these amounts. (The ambient nitrate improvement due to Chena Power Plant NOx reductions using the SIP-reported contribution would be less than 0.1 $\mu g/m^3$ for nitrates [i.e., 3.4 μg nitrate/m^3 times 2.6 percent reduction in daily NOx emissions]).

As discussed in the 2017 proposed approval, the U.S. EPA noted that ADEC also ran the Community Multiscale Air Quality (CMAQ) model to estimate stationary source nitrate contributions to ambient $PM_{2.5}$ concentrations. U.S. EPA noted that, for the 2015 model simulation, the impact from major stationary source NOx to $PM_{2.5}$ at the State Office Building monitor location was 0.5 $\mu g/m^3$ averaged across all modeled episode days (all days within the episode produce $PM_{2.5}$ less than 0.6 $\mu g/m^3$). These observations agree well with the expected improvements discussed in the prior paragraphs.

The estimated nitrate improvements in $PM_{2.5}$ air quality presented above are below the U.S. EPA-recommended 24-hour significant level of 1.3 $\mu g/m^3$ as presented in the recent Draft Precursor Guidance, and only slightly above the significant level when considering sulfate concentrations. This comparison indicates that the environmental benefit of installing NOx controls at Chena Power Plant will produce no noticeable improvement in ambient $PM_{2.5}$ air quality.

Another environmental factor impacting the true effectiveness of a control option is the atmospheric reaction process that leads to conversion of precursor emissions to $PM_{2.5}$. Two major issues must be considered when evaluating the Chena Power Plant's contribution to nitrate and sulfate

[18] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-66.

levels within the FNSB air basin: 1) precursor reaction chemistry in arctic wintertime conditions when exceedances of the $PM_{2.5}$ NAAQS occur, and 2) transport and dispersion of the Chena Power Plant boiler stack plume above and beyond the capped inversion layer that encapsulates the FNSB air basin causing accumulation of ground-level $PM_{2.5}$ within the air basin.

Formation of secondary $PM_{2.5}$ depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity; and the interactions of precursors with preexisting particles and with cloud or fog droplets. The relative contribution to ambient $PM_{2.5}$ concentrations from each of these precursor pollutants varies by climatological area. The relative effect of reducing emissions of these pollutants is also highly variable.[19]

Nitrates are formed from the oxidation of NOx into nitric acid (HNO_3) either during the daytime (reaction with OH) or during the night (reactions with ozone and water). Nitric acid continuously transfers between the gas and the condensed phases through condensation and evaporation processes in the atmosphere. The formation of aerosol ammonium nitrate is favored by the availability of ammonia, temperatures near freezing, and high relative humidity[20]. A 2009 wintertime study[21] in eastern Wisconsin evaluated high $PM_{2.5}$ episodes, which were characterized by low pressure systems, shallow/stable boundary layer, light winds, and increased temperature and relative humidity relative to climatological mean conditions. They often occurred in the presence of regional snow cover at temperatures near freezing, when snow melt and sublimation could generate fog and strengthen the boundary layer inversion. These climatological conditions are not consistent with those that typically generate high $PM_{2.5}$ concentrations in the FNSB, which include low-light conditions with very cold surface temperatures (less than -20 °F) where little to no moisture is available for enhancing particle growth. U.S. EPA acknowledges the identified

[19] Federal Register, Volume 73, page 28325, May 16, 2008, 40 CFR Parts 51 and 52, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$).
[20] NARSTO (2004) Particulate Matter Science for Policy Makers: A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 184287 5.
[21] Overview of the LADCO winter nitrate study: hourly ammonia nitric acid and PM2.5 composition at an urban and rural site pair during PM2.5 episodes in the US Great Lakes region. Atmos. Chem. Phys., 12, 11037–11056, 2012.

limitation of secondary particulate formation from NOx in its proposed approval of the Fairbanks Moderate plan.

Sulfates are typically formed in the atmosphere by formation of sulfuric acid from SO_2 that subsequently reacts with ammonia to form ammonium sulfate. There are three different pathways for the transformation of SO_2 to sulfuric acid[22]:

1. Gaseous SO_2 can be oxidized by the hydroxyl radical (OH) to create sulfuric acid. This gaseous SO_2 oxidation reaction occurs slowly and only in the daytime.
2. SO_2 can dissolve in cloud water (or fog or rainwater), and there it can be oxidized to sulfuric acid by a variety of oxidants, or through catalysis by transition metals such as manganese or iron. If ammonia is present and taken up by the water droplet, then ammonium sulfate will form as a precipitate in the water droplet.
3. SO_2 can be oxidized in reactions in the particle-bound water in the aerosol particles themselves. This process takes place continuously, but only produces appreciable sulfate in alkaline (dust, sea salt) coarse particles.

Again, these climatological conditions that are conducive to sulfate formation from transformation of SO_2 are not consistent with the conditions that typically generate high $PM_{2.5}$ concentrations in the FNSB.

Finally, an issue arises in FNSB related to the dispersion of precursor emissions from the Chena Power Plant boiler stack and the ability of the dispersed emissions to actually impact the ambient air quality monitors. It has been observed, and it is reasonable to expect, that the boiler stack plume is carried above the winter inversion layer. As such, transport of the precursor pollutants occurs above the inversion layer, where the concentrations of the pollutants can be transported and dispersed by the stronger aloft winds. In addition, the Fairbanks $PM_{2.5}$ Source Apportionment Research Study[23] concluded that dominant aloft wind direction during $PM_{2.5}$ episodes is from the northeast, which would transport the Chena Power Plant emissions away from the ambient air

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[22] NARSTO (2004) Particulate Matter Science for Policy Makers: A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 184287 5.

[23] The Fairbanks, Alaska $PM_{2.5}$ Source Apportionment Research Study Winters 2005/2006-2012/2013, and Summer 2012; Final Report, Amendments 6 and 7, December 23, 2013, Tony J. Ward, Ph.D., University of Montana – Missoula , Center for Environmental Health Sciences.

quality monitors located in downtown Fairbanks and North Pole. Figure 1 presents a photograph showing the Chena Power Plant boiler stack exhaust plume height well above the inversion layer.

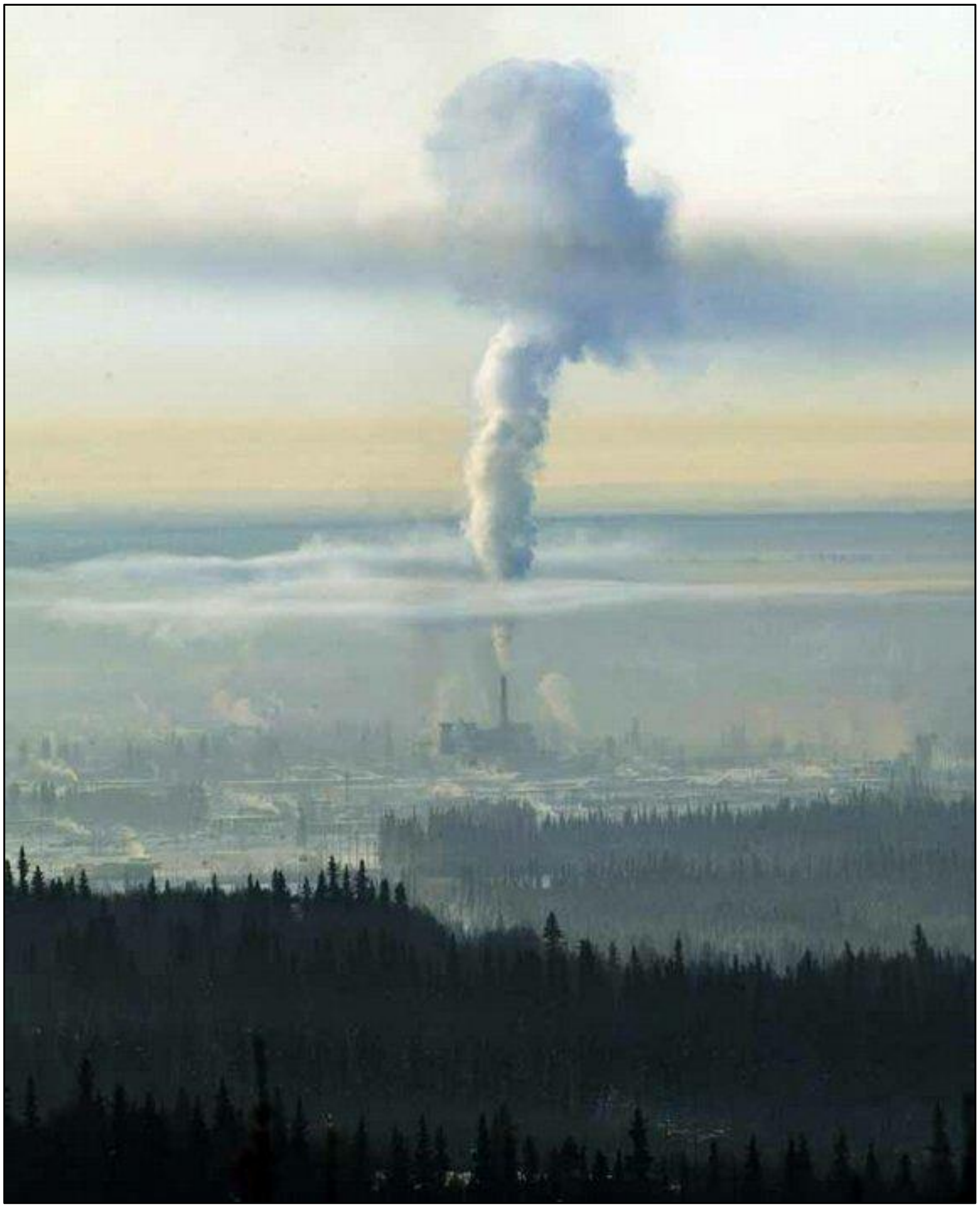

Figure 1. Chena Power Plant exhaust plume.[24]

[24] The exhaust from the Aurora Energy power plant breaks through an inversion layer as seen from the Hagelbarger Road pullout off the Steese Highway. Photo credits: Frank DeGenova, January 30, 2008, http://marcvaldez.blogspot.com/2008/05/wintertime-smokestack-plumes-in.html#links, accessed December 12, 2016.

Data collected at several of the existing FNSB ambient $PM_{2.5}$ monitors corroborate these observations. Figure 2, Figure 3, and Figure 4 present plots of daily Chena Power Plant coal combustion and (wintertime) ambient $PM_{2.5}$ concentrations on days between 2013 and 2015 when the $PM_{2.5}$ standard was exceeded. (ADEC does not use episodes with violations during the summer months because those have historically been associated with exceptional events, such as wildfires.)[25] Each of these monitors collect $PM_{2.5}$ data on a daily schedule. As this series of plots reveal, a very poor correlation exists between Chena Power Plant coal consumption and the ambient $PM_{2.5}$ levels observed at these FNSB monitors. The State Office Building monitor actually shows an inverse relationship (negative slope) between Chena Power Plant coal consumption and ambient $PM_{2.5}$ concentrations.

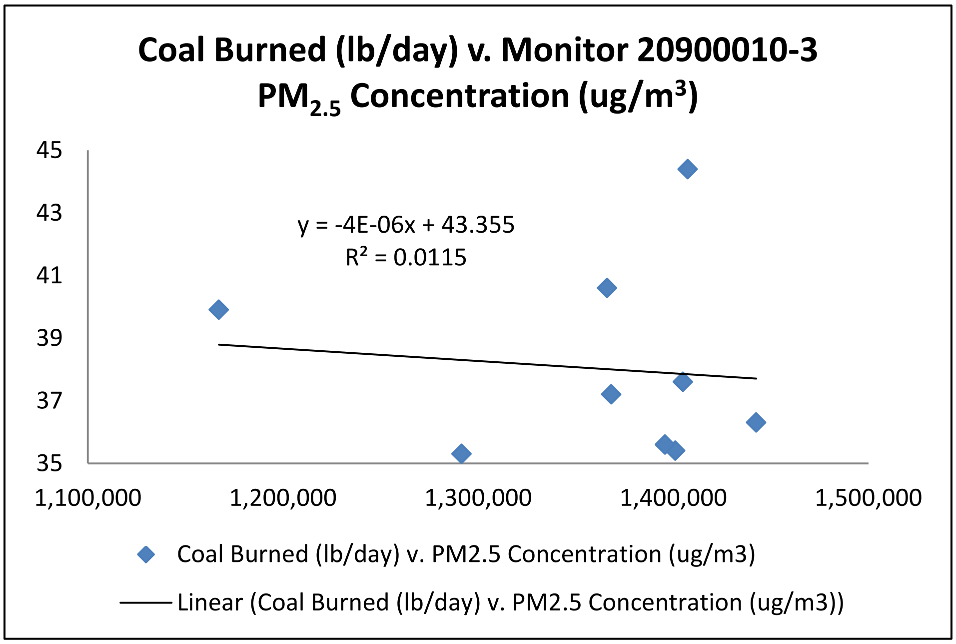

Figure 2. Chena Power Plant daily coal combustion v ambient $PM_{2.5}$ concentrations at the State Office Building monitor (2013).

[25] Federal Register, Volume 82, page 9036, February 2, 2017, 40 CFR Part 52, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

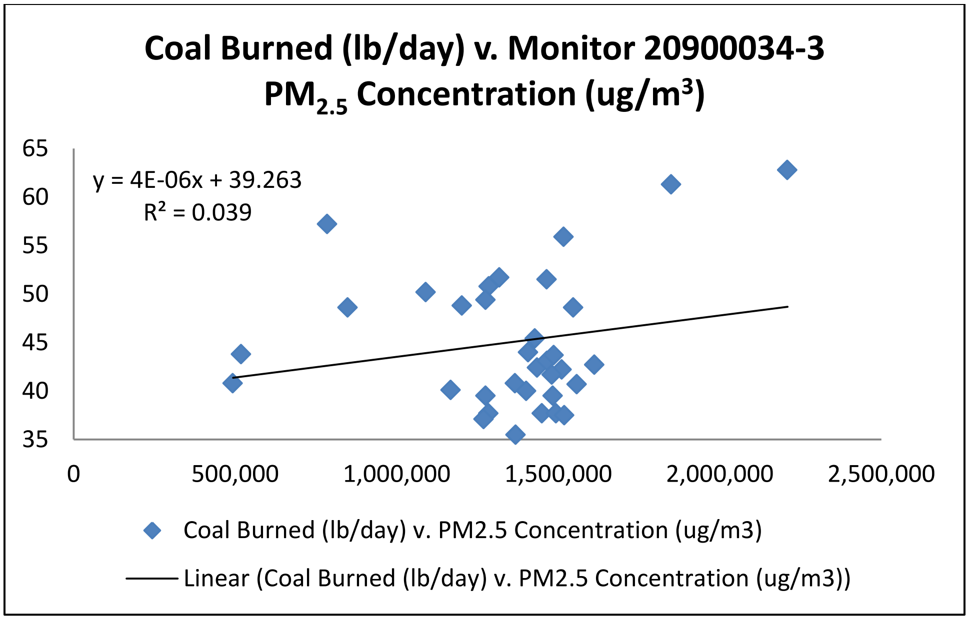

Figure 3. Chena Power Plant daily coal combustion v ambient $PM_{2.5}$ concentrations at the Pioneer Road monitor (2013 to 2015).

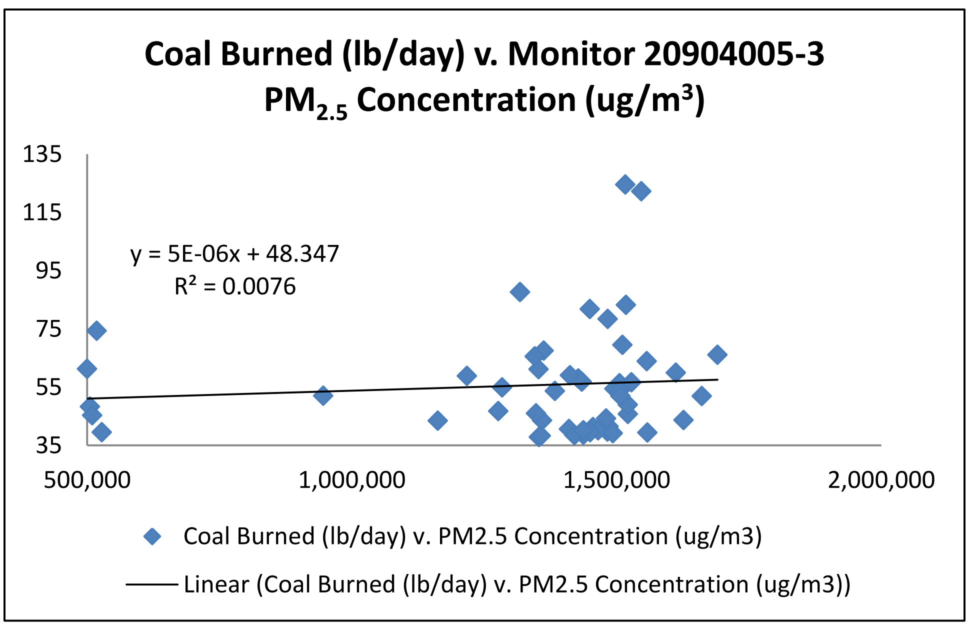

Figure 4. Chena Power Plant daily coal combustion v ambient $PM_{2.5}$ concentrations at downtown Fairbanks monitor 20904005-3 (2013 to 2014).

These poor correlations indicate that changes in Chena Power Plant emissions do not explain the majority of the changes in ambient $PM_{2.5}$ levels. Because the Chena Power Plant emissions are not seemingly influencing the ambient $PM_{2.5}$ concentrations to any significant extent, the ambient levels must be the result of other emission sources in the FNSB.

This observation can be further illustrated using the following example for the highest $PM_{2.5}$ day (early January) in 2015 at downtown Fairbanks monitors when Chena Power Plant coal consumption was at its greatest rate (2.2 million pounds/day). If this was during one of the coldest days, then the Chena Power Plant impact at ground level would have been less than on other days because: 1) the buoyancy term for the Chena Power Plant boiler plume would be at its greatest because the temperature differential between stack and ambient air temperatures would have been greatest, and 2) the momentum term for the boiler plume would also have been at its greatest because the exhaust gas flow rate would be greater than at lesser coal combustion rates. Because the impact of Chena Power Plant emissions would likely have been less on this episode day than other days, the $PM_{2.5}$ mass on the filters in question would had to have been contributed by other sources in the FNSB.

To summarize these environmental considerations related to photochemistry and precursor transport within the FNSB, the U.S. EPA makes the following corroborating points:

> "The low amount of $PM_{2.5}$ from major stationary source NOx precursor emissions is consistent with other aspects of the FNSB Moderate Plan...the photochemistry to produce large amounts of particle bound nitrate is limited during wintertime pollution events in the FNSB nonattainment area. Furthermore, major stationary sources with elevated stacks emit most of their precursors into the extremely stable atmosphere present during wintertime pollution events. Only a fraction of the elevated plumes returns to ground level in the FNSB where air quality monitors are located and much less than might be expected in most parts of the lower 48 states. Therefore, the analysis indicates that NOx emissions from these sources will have very little impact on ground level chemistry and thus on secondary $PM_{2.5}$ formation in the FNSB nonattainment area."[26]

[26] Federal Register, Volume 82, page 9043, February 2, 2017, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

4.2.2 *Energy Considerations*

Retrofit BACT as a means to reduce the pollutant load in an air basin must necessarily look at the effect that employing BACT on a specific source would have on other sources in the air basin and whether this effect would negatively impact the air quality improvement that is presumed to occur when BACT is employed. As discussed below, in the case of the Chena Power Plant, installing add-on control devices for NOx and/or SO_2 control would increase the parasitic load at the Plant. As stated previously, the Chena Power Plant boilers are operated to generate steam that supplies local steam customers as well as steam turbines for electric generation. The four boilers already operate at near full load year round. The only variation in seasonal operating characteristics is the percent of the steam distributed to steam customers. Steam distribution to customers is highest in the heating season, whereas electric generation is highest in the non-heating season. In all seasons, Aurora must meet its contractual steam demand by distributing a constant steam load to its customers. Any surplus steam produced is used to generate electricity that is used on site and/or exported to the grid.

When the parasitic load at the Plant increases, electricity and/or steam exported to the grid is reduced. Regional electricity demands are satisfied by various electricity-generating plants that are members of the regional co-op, i.e., the Golden Valley Electric Association (GVEA). Per its contract, GVEA purchases up to 25 megawatts (MW) of electricity from Aurora. When Aurora, or one of the other co-op facilities, reduces its net electricity generation/export to the grid, GVEA must make up for this reduction by arranging for increased electricity production from one of the other local co-op facilities or import from the Anchorage grid.

Current overall steam production efficiency at Chena Power Plant is approximately 60 percent, i.e., 60 percent of the heat content of the combusted coal is converted to steam. The mechanical loss during electricity generation contributes to an additional 14 percent loss in energy conversion efficiency. In the heating season, when almost all of the $PM_{2.5}$ exceedances are observed within the FNSB, Aurora provides most of its output as steam, and generates (on average) 525 MWh/day that are exported to the grid. Should Aurora install and operate add-on control devices to reduce NOx and/or SO_2 stack emissions, operation of the new equipment will add to the current parasitic load at the plant and lower its overall energy conversion efficiency. The parasitic load of add-control equipment is estimated to be 4 MWh/day for SCR and 6 MWh/day for a wet scrubber, and this loss of electricity for export would have to be supplemented by increased generation at Aurora, other GVEA co-op facilities, or the State-wide grid. When this increased generation is produced by local fuel-consuming facilities, the net change in regional emissions will be close to zero or actually an increase if the supplemented electricity is produced in less-efficient power-generating units.

Overall, when considering add-on control equipment for the existing Chena Power Plant boilers, the situation could occur wherein an emission reduction at Chena would not yield an emission reduction in the FNSB because the parasitic load from the add-on equipment would need to be supplemented by additional fuel consumption (and emissions) from other co-op (i.e., local) facilities. If this situation does indeed occur, a potential reduction in ambient $PM_{2.5}$ concentrations due to emission reductions at Chena Power Plant would be negligible, or completely non-existent, because other emission units in the FNSB would have to increase emissions to compensate for the loss in electricity exported by Aurora. Additionally, the potential regional benefit of emission reductions at the Chena Power Plant is negated by the fact that $PM_{2.5}$ is a secondary air pollutant, and impacts from a specific emission unit are not necessarily observed in close proximity to the emission point.

4.3 SUMMARY OF ENVIRONMENTAL AND ENERGY CONSIDERATIONS

As discussed above, the environmental considerations associated with installation of NOx and/or SO_2 controls on the Chena Power Plant produce uncertain assurances that any improvement in FNSB air quality will result. In fact, the data suggest that insignificant environmental improvements at best could occur.

The energy considerations point to a likely lack of an air quality benefit in FNSB in the event that NOx and/or SO_2 controls are implemented at Chena Power Plant. In fact, such implementation could actually increase the air pollutant load in FNSB from sources more likely to produce a $PM_{2.5}$ ambient impact than Chena Power Plant.

5 DETERMINATION OF BACT

The previous sections evaluated the three aspects that must be considered in a BACT determination, those being economics, environment, and energy. The results of the economic analysis show that none of the NOx or SO_2 control options are economically feasible as retrofit options for the Chena Power Plant. From an environmental standpoint, ADEC recognizes that controlling direct $PM_{2.5}$ emissions is 13 times more effective at reducing ambient $PM_{2.5}$ concentrations than controlling precursor air pollutants that produce secondary $PM_{2.5}$. This, coupled with the fact that the ambient $PM_{2.5}$ benefit that can be achieved by reducing NOx and/or SO_2 emissions is extremely uncertain and difficult to calculate, suggests that no significant environmental benefit would be obtained by requiring controls on Chena Power Plant. A further environmental consideration is that retrofit BACT as a means to reduce the pollutant load in an air basin must necessarily look at the effect that employing BACT on a specific source would have on other sources in the air basin and whether this effect would negatively impact the air quality improvement that is presumed to occur when BACT is employed. Specifically, from an energy standpoint, installing add-on control devices for NOx and/or SO_2 control would increase the parasitic load at the Chena Power Plant. Loss of this energy output would require supplemental energy consumption at other sources within the FNSB to compensate for this parasitic load. This supplemental energy consumption at other sources may actually produce an increase in direct $PM_{2.5}$ emissions if the lost capacity were to be offset by fuel consumption for sources such as wood-burning stoves or oil-fired boilers, which tend to emit more direct $PM_{2.5}$ than Chena Power Plant (see Table 2), and at lower elevations. Furthermore, based on CMB evaluations of PM filters in the FNSB, these lower level sources are already identified as the more significant contributors to ambient $PM_{2.5}$ concentrations. Thus, the energy impacts of requiring NOx and/or SO_2 controls on Chena Power Plant could potentially have the exact opposite effect as desired and produce increases in ambient $PM_{2.5}$ concentrations in the FNSB.

5.1 DETERMINATION OF BACT FOR NOx

Nitrates comprise about 4 percent of the measured $PM_{2.5}$ concentrations in Fairbanks, which equates to a maximum contribution of 8.0 μg/m^3 to the total $PM_{2.5}$ mass on filters. This is because atmospheric conditions do not lead to a high rate of conversion from NOx emissions to ambient $PM_{2.5}$. Controlling NOx emissions is not expected to achieve a meaningful reduction in $PM_{2.5}$. This, in concert with the high cost to install NOx control technology and potential detrimental effects on emissions from other energy consuming sources in the FNSB, leads to the determination that BACT for NOx emissions from Chena Power Plant is the continued use of existing combustion controls.

5.2 *DETERMINATION OF BACT FOR SO_2*

Alaska coal has very low sulfur content, and uncontrolled sulfur emissions are four times lower than at a plant burning "low sulfur coal" in the lower 48 states.[27] The result is that the cost effectiveness of SO_2 control technologies is poorer in Alaska than the lower 48 states. In addition, EPA guidance states use of scrubbers on units smaller than 100 MW is unrealistic.

Current SO_2 emission rates from the Chena Power Plant are one-third of those identified as BACT in the most recent BACT determinations included in the RBLC database. Therefore, BACT for SO_2 emissions from Chena Power Plant is determined to be the continued use of low-sulfur coal.

[27] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-78.

APPENDIX A

CUECost Output for Wet Scrubber for SO_2 Control

INPUTS

Description	Units	Range	Default Values	Input 1
General Plant Technical Inputs				
Location - State	Abbrev.	All States	PA	AK
MW Equivalent of Flue Gas to Control System	MW	100-2000	500	150
Net Plant Heat Rate (w/o APC)	Btu/kWhr		10,500	11,833
Plant Capacity Factor	%	40-90%	65%	65%
Percent Excess Air in Boiler	%		120%	120%
Air Heater Inleakage	%		12%	12%
Air Heater Outlet Gas Temperature	°F		300	300
Inlet Air Temperature	°F		80	80
Ambient Absolute Pressure	In. of Hg		29.4	29.4
Pressure After Air Heater	In. of H2O		-12	-12
Moisture in Air	lb/lb dry air		0.013	0.013
Ash Split:				
Fly Ash	%		80%	80%
Bottom Ash	%		20%	20%
Seismic Zone	Integer	1-5	1	1
Retrofit Factor	Integer	1.0-3.0	1.3	1.6
(1.0 = new, 1.3 = medium, 1.6 = difficult)				
Select Coal	Integer	1-8	1	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	See Column K	Yes	No
		Coals Available in Library		
		Coal 1, Wyoming PRB: 8,227 Btu, 0.37% S, 5.32% ash		
		Coal 2, Armstrong, PA: 13,100 Btu, 2.6% S, 9.1% ash		
		Coal 3, Jefferson, OH: 11,922 Btu, 3.43% S, 13% ash		
		Coal 4, Logan, WV: 12,058 Btu, 0.89% S, 16.6% ash		
		Coal 5, No. 6 Illinois: 10,100 Btu, 4% S, 16% ash		
		Coal 6, Rosebud, MT: 8,789 Btu, 0.56% S, 8.15% ash		
		Coal 7, Lignite, ND: 7,500 Btu, 0.94% S, 5.9% ash		
		Coal 8, "User Specified": 7,560 Btu, 0.3% S, 7% ash		
Economic Inputs				
Cost Basis -Year Dollars	Year		1998	2015
Sevice Life (levelization period)	Years		30	30
Inflation Rate	%		3.00%	3.00%
After Tax Discount Rate (current $'s)	%		9.20%	9.20%
AFDC Rate (current $'s)	%		10.80%	10.80%
First-year Carrying Charge (current $'s)	%		22.30%	22.30%
Levelized Carrying Charge (current $'s)	%		16.90%	16.90%
First-year Carrying Charge (constant $'s)	%		15.70%	15.70%
Levelized Carrying Charge (constant $'s)	%		11.70%	11.70%
Sales Tax	%		6%	6%
Escalation Rates:				
Consumables (O&M)	%		3%	3%
Capital Costs:				
Is Chem. Eng. Cost Index available?	Yes / No		Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer		388	578.4
If "No" input escalation rate.	%		3%	3%
Construction Labor Rate	$/hr		$35	$60
Prime Contractor's Markup	%		3%	3%
Operating Labor Rate	$/hr		$30	$63
Power Cost	Mills/kWh		25	25
Steam Cost	$/1000 lbs		3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs					
SO2 Removal Required	%	90-98%	95%	50%	
L/G Ratio	gal / 1000 acf	95-160	125	125	
Design Scrubber with Dibasic Acid Addition?	Integer	1 or 2	2	2	
(1 = yes, 2 = no)					
Adiabatic Saturation Temperature	°F	100-170	127	127	
Reagent Feed Ratio	Factor	1.0-2.0	1.05	1.05	
(Mole CaCO3 / Mole SO2 removed)					
Scrubber Slurry Solids Concentration	Wt. %		15%	15%	
Stacking, Landfill, Wallboard	Integer	1,2,3	1	1	
(1 = stacking, 2 = landfill, 3 = wallboard)					
Number of Absorbers	Integer	1-6	1	1	
(Max. Capacity = 700 MW per absorber)					
Absorber Material	Integer	1 or 2	1	1	
(1 = alloy, 2 = RLCS)					
Absorber Pressure Drop	in. H2O		6	6	
Reheat Required ?	Integer	1 or 2	1	1	
(1 = yes, 2 = no)					
Amount of Reheat	°F	0-50	25	25	
Reagent Bulk Storage	Days		60	60	
Reagent Cost (delivered)	$/ton		$15	$15	
Landfill Disposal Cost	$/ton		$30	$30	
Stacking Disposal Cost	$/ton		$6	$6	
Credit for Gypsum Byproduct	$/ton		$2	$2	
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%		5%	5%	
SO2 Removal	%		5%	5%	
Flue Gas Handling	%		5%	5%	
Waste / Byproduct	%		5%	5%	
Support Equipment	%		5%	5%	
Contingency by Area (% of Installed Cost)					
Reagent Feed	%		20%	20%	
SO2 Removal	%		20%	20%	
Flue Gas Handling	%		20%	20%	
Waste / Byproduct	%		20%	20%	
Support Equipment	%		20%	20%	
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%		10%	10%	
SO2 Removal	%		10%	10%	
Flue Gas Handling	%		10%	10%	
Waste / Byproduct	%		10%	10%	
Support Equipment	%		10%	10%	
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%		10%	10%	
SO2 Removal	%		10%	10%	
Flue Gas Handling	%		10%	10%	
Waste / Byproduct	%		10%	10%	
Support Equipment	%		10%	10%	
Indicates user inputs specific to Aurora.					

CUECost
Coal Utility Environmental Cost

Version 1, November 25, 1998 (revised 2-9-00 as CUECost3.xls)

INPUTS

Description	Units	Input 1
General Plant Technical Inputs		
Location - State	Abbrev.	AK
MW Equivalent of Flue Gas to Control System	MW	150
Net Plant Heat Rate	Btu/kWhr	11,833
Plant Capacity Factor	%	65%
Total Air Downstream of Economizer	%	120%
Air Heater Leakage	%	12%
Air Heater Outlet Gas Temperature	°F	300
Inlet Air Temperature	°F	80
Ambient Absolute Pressure	In. of Hg	29.4
Pressure After Air Heater	In. of H2O	-12
Moisture in Air	lb/lb dry air	0.013
Ash Split:		
Fly Ash	%	80%
Bottom Ash	%	20%
Seismic Zone	Integer	1
Retrofit Factor	Integer	1.6
(1.0 = new, 1.3 = medium, 1.6 = difficult)		
Select Coal	Integer	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	No
Economic Inputs		
Cost Basis -Year Dollars	Year	2015
Sevice Life (levelization period)	Years	30
Inflation Rate	%	3%
After Tax Discount Rate (current $'s)	%	9%
AFDC Rate (current $'s)	%	11%
First-year Carrying Charge (current $'s)	%	22%
Levelized Carrying Charge (current $'s)	%	17%
First-year Carrying Charge (constant $'s)	%	16%
Levelized Carrying Charge (constant $'s)	%	12%
Sales Tax	%	6%
Escalation Rates:		
Consumables (O&M)	%	3%
Capital Costs:		
Is Chem. Eng. Cost Index available?	Yes / No	Yes
If "Yes" input cost basis CE Plant Index.	Integer	578.4
If "No" input escalation rate.	%	3%
Construction Labor Rate	$/hr	$60
Prime Contractor's Markup	%	3%
Operating Labor Rate	$/hr	$63
Power Cost	Mills/kWh	25
Steam Cost	$/1000 lbs	3.5

Limestone Forced Oxidation (LSFO) Inputs		
SO2 Removal Required	%	50%
L/G Ratio	gal / 1000 acf	125
Design Scrubber with Dibasic Acid Addition?	Integer	2
(1 = yes, 2 = no)		
Adiabatic Saturation Temperature	°F	127
Reagent Feed Ratio	Factor	1.05
(Mole CaCO3 / Mole SO2 removed)		
Scrubber Slurry Solids Concentration	Wt. %	15%
Stacking, Landfill, Wallboard	Integer	1
(1 = stacking, 2 = lanfill, 3 = wallboard)		
Number of Absorbers	Integer	1
(Max. Capacity = 700 MW per absorber)		
Absorber Material	Integer	1
(1 = alloy, 2 = RLCS)		
Absorber Pressure Drop	in. H2O	6
Reheat Required ?	Integer	1
(1 = yes, 2 = no)		
Amount of Reheat	°F	25
Reagent Bulk Storage	Days	60
Reagent Cost (delivered)	$/ton	$15
Landfill Disposal Cost	$/ton	$30
Stacking Disposal Cost	$/ton	$6
Credit for Gypsum Byproduct	$/ton	$2
Maintenance Factors by Area (% of Installed Cost)		
Reagent Feed	%	5%
SO2 Removal	%	5%
Flue Gas Handling	%	5%
Waste / Byproduct	%	5%
Support Equipment	%	5%
Contingency by Area (% of Installed Cost)		
Reagent Feed	%	20%
SO2 Removal	%	20%
Flue Gas Handling	%	20%
Waste / Byproduct	%	20%
Support Equipment	%	20%
General Facilities by Area (% of Installed Cost)		
Reagent Feed	%	10%
SO2 Removal	%	10%
Flue Gas Handling	%	10%
Waste / Byproduct	%	10%
Support Equipment	%	10%
Engineering Fees by Area (% of Installed Cost)		
Reagent Feed	%	10%
SO2 Removal	%	10%
Flue Gas Handling	%	10%
Waste / Byproduct	%	10%
Support Equipment	%	10%

SUMMARY OF COSTS		
Description	**Units**	**Input 1**
SO2 Control Costs		**LSFO**
Total Capital Requirement (TCR)	$	$88,476,054
	$/kW	$590
First Year Costs		
Fixed O&M	$	$5,133,156
	$/kW-Yr	34.22
	Mills/kWH	6.01
	$/ton SO2 removed	$18,604.0
Variable O&M	$	$621,703
	$/kW-Yr	4.14
	Mills/kWH	0.73
	$/ton SO2 removed	$2,253.2
Fixed Charges	$	$19,730,160
	$/kW-Yr	131.53
	Mills/kWH	23.10
	$/ton SO2 removed	$71,507.6
TOTAL	$	$25,485,020
	$/kW-Yr	169.90
	Mills/kWH	29.84
	$/ton SO2 removed	$92,365
Levelized Current Dollars		
Fixed O&M	$/kW-Yr	46.57
	Mills/kWH	8.18
	$/ton SO2 removed	$25,316.6
Variable O&M	$/kW-Yr	5.64
	Mills/kWH	0.99
	$/ton SO2 removed	$3,066.2
Fixed Charges	$/kW-Yr	99.68
	Mills/kWH	17.51
	$/ton SO2 removed	$54,191.9
TOTAL	$/kW-Yr	151.89
	Mills/kWH	26.68
	$/ton SO2 removed	$82,574.7
Levelized Constant Dollars		
Fixed O&M	$/kW-Yr	34.22
	Mills/kWH	6.01
	$/ton SO2 removed	$18,604.0
Variable O&M	$/kW-Yr	4.14
	Mills/kWH	0.73
	$/ton SO2 removed	$2,253.2
Fixed Charges	$/kW-Yr	69.01
	Mills/kWH	17.22
	$/ton SO2 removed	$53,289.1
TOTAL	$/kW-Yr	107.38
	Mills/kWH	23.95
	$/ton SO2 removed	$74,146.3

LSFO Material Balance - Preliminary			Case1
Flue Gas, Downstream of ID Fans			
Temperature	°F		295
Pressure	in. H2O		10
Flow Rate	SCFM		205,106
Flow Rate	ACFM		295,678
CO2	lb/hr		167,773
N2	lb/hr		662,514
SO2	lb/hr		194
O2	lb/hr		52,552
HCl	lb/hr		0
Other Gases	lb/hr		150
H2O	lb/hr		59,659
Fly Ash	lb/hr		15
Total (gas only)	lb/hr		942,842
Flue Gas, to Absorber			
Temperature	°F		295
Pressure	in. H2O		10
Flow Rate	SCFM		205,106
Flow Rate	ACFM		295,678
CO2	lb/hr		167,773
N2	lb/hr		662,514
SO2	lb/hr		194
O2	lb/hr		52,552
HCl	lb/hr		0
Other Gases	lb/hr		150
H2O	lb/hr		59,659
Fly Ash	lb/hr		15
Total (gas only)	lb/hr		942,842
Flue Gas, from Absorbers (total)			
Temperature	°F		127
Pressure	in. H2O		4
Flow Rate	SCFM		213,946
Flow Rate	ACFM		243,352
CO2	lb/hr		167,840
N2	lb/hr		662,836
SO2	lb/hr		97
O2	lb/hr		52,625
HCl	lb/hr		0
Other Gases	lb/hr		150
H2O	lb/hr		84,552
Fly Ash	lb/hr		15
Total (gas only)	lb/hr		968,099
Heat Capacities			
O2	Btu/lbmol°F		7.213
CO2	Btu/lbmol°F		9.354
N2	Btu/lbmol°F		6.999
H2O	Btu/lbmol°F		8.069
NO	Btu/lbmol°F		7.164
SO2	Btu/lbmol°F		9.830
HCl	Btu/lbmol°F		6.951
O2	Btu/lb°F		0.225
CO2	Btu/lb°F		0.213
N2	Btu/lb°F		0.250
H2O	Btu/lb°F		0.448
NO	Btu/lb°F		0.239
SO2	Btu/lb°F		0.153
HCl	Btu/lb°F		0.191
Reheated Gas Temperature:	°C		66.7
	K		339.7
FGD Outlet Temperature:	°C		52.8
	K		325.8
Total Btu/hr	Btu/hr		6,275,628

Hot Reheat Air			
Temperature	°F		440
Pressure	in. H2O		1
Flow Rate	SCFM		19,267
Flow Rate	ACFM		33,852
N2	lb/hr		66,106
O2	lb/hr		19,936
H2O	lb/hr		1,133
Total	lb/hr		87,175
Heat Capacities of Hot Reheat Air			
O2	Btu/lbmol°F		7.332
N2	Btu/lbmol°F		7.113
H2O	Btu/lbmol°F		8.338
O2	Btu/lb°F		0.229
N2	Btu/lb°F		0.254
H2O	Btu/lb°F		0.463
Heated Temperature:	°C		226.7
	K		499.7
FGD Outlet Temperature:	°C		66.7
	K		339.7
Heat Capacities of Inlet Reheat Air			
O2	Btu/lbmol°F		7.304
N2	Btu/lbmol°F		7.087
H2O	Btu/lbmol°F		8.276
O2	Btu/lb°F		0.228
N2	Btu/lb°F		0.253
H2O	Btu/lb°F		0.459
Heated Temperature:	°C		226.7
	K		499.7
Inlet Air Temperature:	°C		26.7
	K		299.7
Required Heat	Btu/hr		7,844,535
Oxidation Air (total)			
Temperature	°F		60
Pressure	in. H2O		0
Flow Rate	SCFM		94
Flow Rate	ACFM		95
N2	lb/hr		321
O2	lb/hr		97
H2O	lb/hr		5
Total (gas only)	lb/hr		423
Limestone to Ball Mill			
Temperature	°F		80
Wt.% Solids	wt. %		100%
Inerts	lb/hr		8
CaCO3	lb/hr		159
Total	lb/hr		167
Limestone Slurry to Limestone Slurry Tank			
Temperature	°F		90
Flow Rate	GPM		0.6
Wt.% Solids	wt. %		40%
Inerts	lb/hr		8
CaCO3	lb/hr		159
H2O	lb/hr		250
Total	lb/hr		417
Limestone Slurry to Reaction Mix Tank (total)			
Temperature	°F		68
Flow Rate	GPM		1.4
Wt.% Solids	wt. %		20%
Inerts	lb/hr		8
CaCO3	lb/hr		159
H2O	lb/hr		667
Total	lb/hr		834

Slurry to Absorber			
Temperature	°F		126
Flow Rate	GPM		30,047
Wt.% Solids	wt. %		15%
CaSO3*1/2H2O	lb/hr		0
CaSO4*2H2O	lb/hr		2,448,768
Inerts	lb/hr		73,717
CaCl2	lb/hr		0
CaCO3	lb/hr		71,177
H2O	lb/hr		14,697,418
Total	lb/hr		17,291,080
Slurry from Rxn Tank to Thickener			
Temperature	°F		126
Flow Rate	GPM		3.2
Wt.% Solids	wt. %		15%
CaSO3*1/2H2O	lb/hr		0
CaSO4*2H2O	lb/hr		260
Inerts	lb/hr		8
CaCl2	lb/hr		0
CaCO3	lb/hr		8
H2O	lb/hr		1,563
Total	lb/hr		1,839

LSFO Equipment Capital Costs			Case1
Cost Basis (Year)			***2015***
		Sizing Criteria	
Reagent Feed System	$	kpph Reag.	$10,628,589
Ball Mill & Hydroclone System	$	TPH Reag.	$2,767,930
DBA Acid Tank (pump, heater, agitator)	$	gpm DBA	$0
SO2 Removal System	$	kpph SO2	$2,850,322
Absorber Tower	$	kACFM	$8,477,991
Spray Pumps	$	slurry gpm	$629,404
Flue Gas Handling System	$	*	$4,823,011
ID Fans	$	ACFM	$973,101
Waste / Byproduct Handling System	$	kpph SO2	$120,818
Thickener System	$	TPH solids	$172,635
Support Equipment	$	MW	$2,167,145
Chimney	$	ACFM	$3,768,539
TOTAL	$		$37,379,484
* *Based on flue gas flow and reheat temperature.*			
Capital Costs with Retrofit Factors			
Reagent Feed System	$		$17,005,742
Ball Mill & Hydroclone System	$		$4,428,688
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$4,560,516
Absorber Tower	$		$13,564,785
Spray Pumps	$		$1,007,047
Flue Gas Handling System	$		$7,716,817
ID Fans	$		$1,556,962
Waste / Byproduct Handling System	$		$193,308
Thickener System	$		$276,215
Support Equipment	$		$3,467,432
Chimney	$		$6,029,662
TOTAL	$		$59,807,174
General Facilities			
Reagent Feed System	$		$1,700,574
Ball Mill & Hydroclone System	$		$442,869
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$456,052
Absorber Tower	$		$1,356,479

Spray Pumps	$		$100,705
Flue Gas Handling System	$		$771,682
ID Fans	$		$155,696
Waste / Byproduct Handling System	$		$19,331
Thickener System	$		$27,622
Support Equipment	$		$346,743
Chimney	$		$602,966
TOTAL	$		$5,980,717
Engineering Fees			
Reagent Feed System	$		$1,700,574
Ball Mill & Hydroclone System	$		$442,869
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$456,052
Absorber Tower	$		$1,356,479
Spray Pumps	$		$100,705
Flue Gas Handling System	$		$771,682
ID Fans	$		$155,696
Waste / Byproduct Handling System	$		$19,331
Thickener System	$		$27,622
Support Equipment	$		$346,743
Chimney	$		$602,966
TOTAL	$		$5,980,717
Contingency			
Reagent Feed System	$		$3,401,148
Ball Mill & Hydroclone System	$		$885,738
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$912,103
Absorber Tower	$		$2,712,957
Spray Pumps	$		$201,409
Flue Gas Handling System	$		$1,543,363
ID Fans	$		$311,392
Waste / Byproduct Handling System	$		$38,662
Thickener System	$		$55,243
Support Equipment	$		$693,486
Chimney	$		$1,205,932
TOTAL	$		$11,961,435
Total Plant Cost (TPC)	$		$83,730,044
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$		$86,241,945
Total Cash Expended (TCE)	$		$86,241,945
Allow. for Funds During Constr. (AFDC)	$		$0
Total Plant Investment (TPI)	$		$86,241,945
Preproduction Costs	$		$2,232,307
Inventory Capital	$		$1,802
Total Capital Requirement (TCR)	$		**$88,476,054**
	$/kW		$590
Maintenance Cost by Area			Case1
TPC w/o Retrofit Factor			
Reagent Feed System	$		$15,305,168
Ball Mill & Hydroclone System	$		$3,985,819
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$4,104,464
Absorber Tower	$		$12,208,307
Spray Pumps	$		$906,342
Flue Gas Handling System	$		$6,945,135
ID Fans	$		$1,401,265

Waste / Byproduct Handling System	$		$173,977
Thickener System	$		$248,594
Support Equipment	$		$3,120,689
Chimney	$		$5,426,696
TOTAL	$		$53,826,457
First Year Maintenance Costs			
Reagent Feed System	$		$765,258
Ball Mill & Hydroclone System	$		$199,291
DBA Acid Tank (pump, heater, agitator)	$		$0
SO2 Removal System	$		$205,223
Absorber Tower	$		$610,415
Spray Pumps	$		$45,317
Flue Gas Handling System	$		$347,257
ID Fans	$		$70,063
Waste / Byproduct Handling System	$		$8,699
Thickener System	$		$12,430
Support Equipment	$		$156,034
Chimney	$		$271,335
TOTAL	$		$2,691,323

LSFO O&M Data and Costs

			Case1
Cost Basis (Year)			***2015***
Parameters			
Reagent Required	lbs/hr		167
	lbs/MMBtu		0.336
DBA Required	lbs/hr		0.0
Percent SO2 Removal	%		50%
FGD Sludge to Disposal	lbs/hr, dry		276
Steam to FGD System	lbs/hr		9,173
Total FGD Power Consumption	kW		3,000
FGD Byproduct	lbs/hr		0
Fixed O&M Costs			
Number of Operators			12
(40 hrs/week)			
Operating Labor Cost **	$/yr		$1,629,903
Maint. Labor & Matls. Cost	$/yr		$2,691,323
Admin. & Support Labor	$/yr		$811,930
TOTAL	$/yr		$5,133,156
Variable Operating Costs **			
Reagent Costs	$/yr		$7,124
DBA Costs	$/yr		$0
Disposal Costs	$/yr		$4,713
Credit for Byproduct	$/yr		$0
Steam Costs	$/yr		$182,817
Power Costs	$/yr		$427,050
TOTAL	$/yr		$621,703

** *These costs assume inputs are in current dollars (no escalation included).*

Intermediate Material Balance Calcs.

			Case1
Sulfite Reaction			
SO2	lbmole/hr		1.51
CaCO3	lbmole/hr		1.51
H2O	lbmole/hr		0.76
CaSO3*1/2H2O	lbmole/hr		1.51
CO2	lbmole/hr		1.51
SO2	lb/hr		97
CaCO3	lb/hr		151
H2O	lb/hr		14

CaSO3*1/2H2O	lb/hr		195
CO2	lb/hr		67
Sulfate Reaction			
CaSO3*1/2H2O	lbmole/hr		1.51
O2	lbmole/hr		0.76
H2O	lbmole/hr		2.27
CaSO4*2H2O	lbmole/hr		1.51
CaSO3*1/2H2O	lb/hr		195
O2	lb/hr		24
H2O	lb/hr		41
CaSO4*2H2O	lb/hr		260
Water in Absorber			
Mole Fraction H2O in Absorber	%		0.1389
Moles H2O in Absorber	lbmole		4,693.33
DBA Feed Calculations			
SO2 Removed	lbs/hr		97
DBA Added	lbs/hr		0.00
DBA Added	GPM		0.00

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November 16, 2017

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

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

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

ADEC and EPA reviewed the BACT analysis provided for the Aurora Chena Power Plant and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

---

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry

[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

injection or spray dry system. It further states that the installation of such technologies would be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual. Please see Comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
8. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

Aurora Energy – Chena Power Plant
BACT Analysis Review Comments
Report dated March 2017 – Environmental Resources Management

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

1. Equipment Life – Some of the calculations[1] submitted with the analysis use a 10 year equipment life at ten percent interest rate. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. The analysis must also provide written basis for the interest rate assumed if it differs from the standard seven percent rate used in the EPA Air Pollution Control Cost Manual.
2. SO_2 Control Technologies – The BACT analyses must include substantive analysis of the following four SO_2 control technologies, at a minimum: wet scrubbing (such as limestone slurry forced oxidation), spray-dry scrubbing, dry flue gas desulfurization (dry scrubbing), and dry sorbent injection. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question.
4. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided.
5. EPA Cost Spreadsheets – The EPA has recently updated the cost manual chapters pertaining to SCR and SNCR, and developed cost spreadsheets to be used for evaluation of this technology for cost effectiveness[2]. The cost analyses for these technologies must be consistent with the updated cost manual chapter and cost spreadsheet.
6. Space Constraints – In order to establish a control technology as not technically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
7. Retrofit Costs – EPA Region 10 believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.
8. Potential vs. Actual Emissions – All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The

[1] See for example, NOx cost calcs-MARCH 2017 FINAL.xlsx
[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

9. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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CERTIFIED MAIL: 7014 0510 0001 9932 8880
Return Receipt Requested

April 24, 2015

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Voluntary BACT Analysis for Chena Power Plant

Dear Mr. Fish:

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

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

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

<u>Background</u>
EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

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

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

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

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

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

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

AURORA ENERGY

December 22, 2017

Denise Koch
Director, Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, AK 99811-1800

Subject: Response to November 16, 2017 request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Ms. Koch:

Aurora is responding to the request for additional information to supplement the Best Available Control Technology (BACT) Technical Memorandum provided to the Alaska Department of Environmental Conservation (ADEC) on March 20, 2017. In response, a detailed BACT analysis for sulfur controls is included as an addendum to the original BACT analysis. We are confident that our initial submittal and enclosed response are sufficient to make a preliminary BACT determination consistent with our selected BACT. Aurora is convinced expending additional and substantial resources to provide further analysis is not warranted considering that ADEC has established, through moderate area planning efforts, that our facility's contribution to ground level particulate matter during air quality events is minimal.

Aurora realizes that a BACT analysis must be conducted for applicable stationary sources regardless of the level of contribution to the problem or impact on the area's ability to achieve attainment. However, the request for additional information hints at the Departments next steps of requiring heat and power producers, such as Aurora, to install technology which will have minimal impact on bringing the area into attainment.

Collectively, the large stationary sources contribute less than 10% of the total $PM_{2.5}$ concentration as illustrated by ADEC.[1] According to the moderate area planning efforts, Aurora makes up less than 1% of the contribution from large stationary sources.[2] The cost to mitigate Aurora's less than one percent contribution to ground-level particulate matter would require tens of millions of dollars in capital investments and annualized operating costs which would be passed on to the consumer in increased power and district heat rates. Current electric rates in the Interior are already some of the highest in the country. Market competition dictates that district heating costs are priced to be competitive with oil and natural gas. An increase in district heat

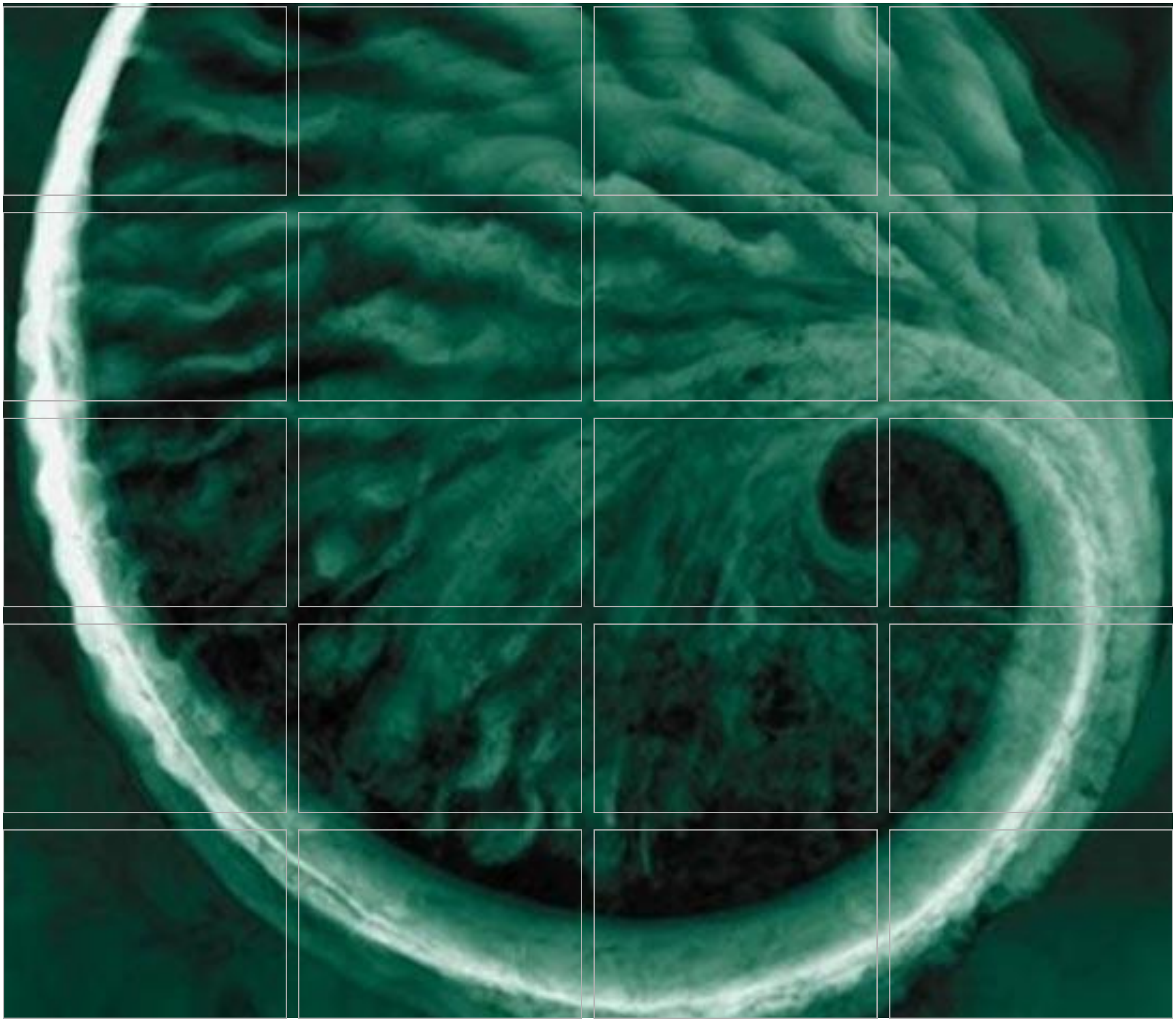
[1] Clear the Air Conference. 2017. http://co.fairbanks.ak.us/transportation/Pages/AQConference2017.aspx, Source Apportionment Presentation, Slide 21, accessed 11/29/2017.
[2] State Implementation Plan, ADEC. 2014. http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/III.D.5-PM2.5_SIP_Sections-Adopted_09.07.16.pdf, pg 167 of 233. Accessed 11/29/2017.

rates could encourage consumers to switch to ground-level heating sources, such as oil and wood, which would exacerbate the area's air quality problems and impede local progress toward attainment.

In short, BACT is prohibitively costly, impractical, and ineffective in this situation. The implementation of additional control technology on Aurora would, at best, provide minimal benefit to air quality and would likely result in unintended consequences. Aurora believes that ADEC, EPA and Aurora could work together to identify a mechanism in the planning process that recognizes the air quality benefit of Aurora's district heating system which displaces the equivalent of over two million gallons of wintertime ground-level heating oil emissions. As such, district heating is a proven solution to Fairbanks' air quality issues. Aurora hopes that ADEC will take these points into consideration in anticipation of the Department's preliminary BACT determination for public review.

Sincerely,

Buki Wright
President



Addendum to Best Available Control Technology Analysis

Chena Power Plant
Fairbanks, Alaska

Prepared for:
Aurora Energy, LLC

December 2017

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Addendum to Best Available Control Technology Analysis

Chena Power Plant
Fairbanks, Alaska

Prepared for:
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December 2017

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ACRONYMS AND ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
BACT	best available control technology
CAA	Clean Air Act
CMB	chemical mass balance
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FNSB	Fairbanks North Star Borough
ft	foot or feet
GVEA	Golden Valley Electric Association
LAER	Lowest Achievable Emission Rate
lb/hr	pound per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NOx	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	Normalized stoichiometric ratio
OH	hydroxyl
PM	particulate matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
RACT	reasonable available control technology
SIP	State Implementation Plan
SO_2	sulfur dioxide
ton/yr	tons per year
U.S.	United States
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic

1 INTRODUCTION

As described in the original Best Available Control Technology (BACT) Analysis report, Aurora Energy, LLC (Aurora) operates four coal-fired boilers, three similarly-sized smaller units and one larger unit, at the facility known as the Chena Power Plant (Chena).[1] The combined exhaust from the four boilers at Chena is currently directed to a single fabric filter for control of particulate matter (PM). Figure 1 presents an aerial view of the Chena facility where the four coal-fired boilers are located. The duct work from the three smaller boilers can be seen coming out of two different buildings along 1st Avenue. The duct work from the larger boiler is not clearly visible, but comes out of a third building and connects to the other combined ducts just prior to entering the south side of the fabric filter housing. The fabric filter housing, visible as a blue structure in the figure, is one of the larger individual structures that occupies the site. The PM collected in the fabric filter is conveyed to the adjacent ash silo for storage until trucked off site.

The four Chena boilers combust low sulfur coal to achieve a sulfur dioxide (SO_2) emission rate equivalent to 0.39 pounds of SO_2 per million Btu of heat input (lb SO_2/MMBtu). The coal is "local" coal mined at the Usibelli Coal Mine in Healy, Alaska.

The techniques available for controlling SO_2 emissions from a coal-fired boiler include the following:

- Use of flue gas desulfurization (FGD) technology
    - Wet scrubber
    - Dry scrubber (lime injection and spray dryer/absorber)
    - Limestone or other dry sorbent injection

Most wet FGD systems employ two stages: one for fly ash removal and the other for SO_2 removal. In wet scrubbing systems, the flue gas first passes through a fly ash removal device, either an electrostatic

[1] Environmental Resources Management, Inc., Best Available Control Technology Analysis, Chena Power Plant, Fairbanks, AK, revised March 2017.

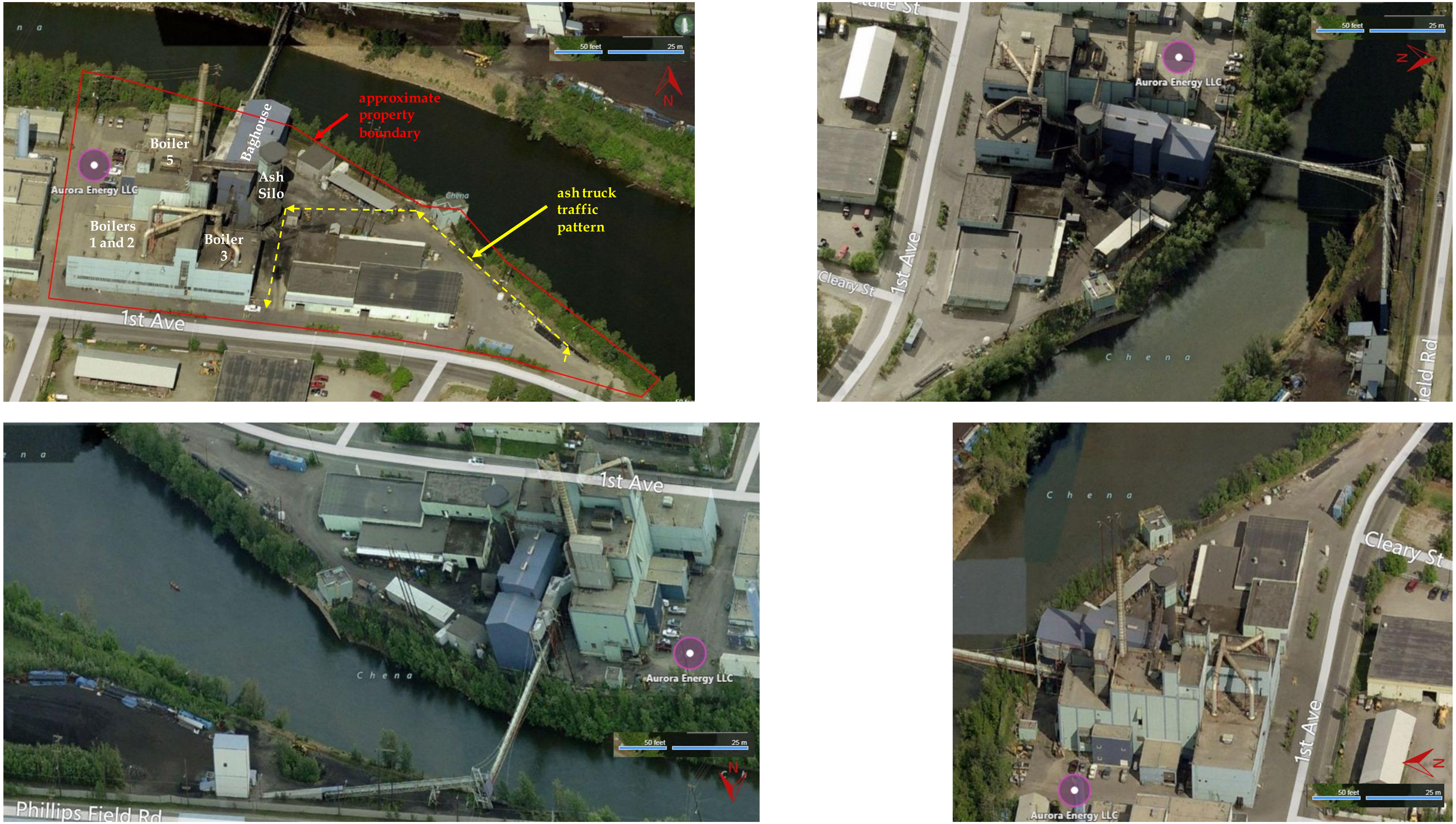

Figure 1. Aerial View of Chena Power Plant.

precipitator (ESP) or a fabric filter, and then into the SO_2 absorber. Due to cost constraints, wet FGD systems are not commonly used to reduce SO_2 emissions from boilers combusting low-sulfur coal. The original Chena Power Plant BACT Analysis presented a detailed discussion of the technical feasibility and cost of using a wet scrubber at Chena. Wet scrubbing technology was discounted as BACT in the original analysis due to the high cost-effectiveness (although many other technical challenges, such as space constraints, exist when considering wet scrubber technology at Chena). Additional discussion of FGD using a wet scrubber is therefore not needed at this time.

1.1 ADDITIONAL SO_2 CONTROLS SELECTED FOR EVALUATION

This BACT Addendum concentrates on evaluation of dry FGD technology, which consists of the spray dryer/absorber (SDA) option and the dry sorbent injection (DSI) option. In SDA or DSI operations, the SO_2 is first reacted with the sorbent, and then the flue gas passes through a PM control device.

The ability of a SDA or DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the calcium or sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form hydrochloric acid (HCl) in the flue gas and consume a portion of the injected lime. In an SDA system, actual sorbent consumption is influenced by the discharge temperature selected for the system, as this controls the amount of water sprayed into the flue gas. .

The ability to employ an add-on SO_2 control system also is influenced by site-specific factors, including space limitations. Use of a SDA or DSI system in concert with the somewhat peculiar equipment orientation at Chena, i.e., four boilers controlled by a single fabric filter, would require major alterations of the existing ductwork and possibly the fabric filter. The boiler houses and ducts would need to be retrofit with various equipment items to accommodate the sorbent delivery systems and PM handling systems required by a SDA or DSI system.

The following paragraphs present an overview of these two selected dry FGD technologies in general and a description of some of the site-specific issues associated with their use at Chena.

1.2 SPRAY DRYER/ABSORBER

A U.S. EPA Air Pollution Control Technology Fact Sheet for FGD technologies states that scrubbers are capable of reduction efficiencies in the range of 50 to 98%.[2] The highest removal efficiencies are achieved by wet scrubbers, and the lowest by dry scrubbers (typically less than 80%). Low SO_2 loadings to a dry absorber, as are obtained when using low sulfur coal, tend to produce lower removal efficiencies, between 40% and 70%. For comparison, the Consent Decree between the Golden Valley Electric Association, Inc. (GVEA) and the US EPA (dated November 19, 2012) and the subsequent Minor Permit issued by the Alaska Department of Environmental Conservation (ADEC) specified a 30-day SO_2 emission rate of no greater than 0.10 lb/MMBtu for Healy Power Plant (Healy) Unit 2 in Healy, AK while using SDA.[3] The Healy facility combusts similar coal as the Chena Power Plant, which produces an average uncontrolled emission rate of 0.39 lb SO_2/MMBtu. Achieving an emission rate of 0.10 lb SO_2/MMBtu thus represents a 74% reduction of average uncontrolled SO_2 emissions, which generally falls within the published range of performance for a SDA system.

In SDA systems, a slurry of sorbent material and water is fed to a spray dryer tower. In the tower, the slurry is atomized and injected into the gas, where droplets react with SO_2 as the liquid evaporates. This action produces a dry product that is collected in the bottom of the spray dryer and in the downstream PM removal equipment (i.e., fabric filter or electrostatic precipitator, ESP). The majority of the reaction takes place in the spray dryer. When a fabric filter is used, as the PM collects on the filter cloth, a filter cake would develop and allow the gas a second chance to react with the reagent, thus increasing utilization of the reagent and control efficiency. The fabric filter or ESP, downstream of the spray dryer, removes the PM, ash, reaction products (e.g., $CaSO_3$, $CaSO_4$, Na_2SO_4), and unreacted sorbent. The waste product can be disposed, sold as a by-product (depending on its quality), or recycled to the slurry. Various calcium and sodium-based reagents can be utilized as sorbent. SDA systems typically inject lime because it is more reactive than limestone and less expensive than sodium-based reagents. SO_2 control efficiencies

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[2] US EPA, Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf, accessed December 18, 2017.

[3] Technical Analysis Report – Permit AQ0173MSS01, April 14, 2014, Golden Valley Electric Association-Healy Power Plant.

are somewhat comparable for wet limestone scrubbers and spray dry systems, however, the capital and operating cost for spray dryer systems are lower than for wet systems, because equipment for handling liquid reagent and wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber because the flue gas is less humid.

It is reasonable to expect that SDA technology performance depends on the facility-specific process characteristics. The properties most important for a SDA application are an inlet gas temperature that allows the slurry to be evaporated in the flue gas (a necessity for a spray dry scrubber), adequate mixing and residence time that allow the sorbent to react with the SO_2 in the gas, and the use of a PM control device to separate the reaction products from the gas stream.

1.2.1 Site-specific Considerations for Using SDA at Chena

Flue Gas Take-off Point--The Chena plant employs a fabric filter to remove the PM from the combined flue gases of the four boilers operating at the site. A very short duct run, only about 10 feet, exists between the location where the flue gases are combined and the combined gas enters the fabric filter housing. At this point, the flue gas from Boiler 5 combines with the previously-combined flue gas from Boilers 1, 2, and 3. Three general SDA equipment orientations are possible for taking off flue gas for treatment in a spray dryer tower at Chena. The first orientation would take the flue gas from the point where all boiler flue gases have been combined prior to entering the fabric filter, i.e., in the 10-foot (ft) duct run. A second orientation would take the flue gas from Boiler 5 only (at some point prior to the 10-ft duct run) and provide control only of the SO_2 emitted by the larger boiler. A third orientation would take the combined flue gas as it exits the fabric filter. In any of these orientations, construction of duct work needed to deliver flue gas to the spray dryer tower would be complicated. Major changes to the gas flue flow regime would occur for any take-off point prior to the fabric filter. Major structural modifications of the fabric filter housing would be needed to accommodate a take-off point downstream of the fabric filter.

Spray Dryer Tower Location-- The Chena site is extremely congested, and very little vacant space is available for new construction. Therefore, spatial considerations are necessary when locating a spray dryer tower. A similarly sized boiler facility exists at the Golden Valley Electric Association (GVEA) plant in Healy, Alaska. The Healy Unit #2 boiler (683 MMBtu/hr) employs a SDA system, which is a similarly sized boiler burning run-of-mine coal from Usibelli. The spray dryer tower at the GVEA plant is 34 ft 9 in in diameter and stands 36 ft 9 in from the ground with a 29 ft 4 in, 60° Cone Hopper. Because of the congested area at Chena, a spray dryer tower would have to be located on the northern boundary of the property south of the river on the east or west of the outfall house. That location would situate the tower approximately 150 to 250 ft away from the combined flue gas junction just prior to the fabric filter inlet. After exiting the spray dryer tower, the treated gas would be redirected back to the 10-ft duct run at the fabric filter inlet for removal of PM. The baghouse design for the flue gas temperature at the inlet is 350 °F. Typically, the combined flue gases are between 300 and 315 °F at the inlet of the baghouse. The outlet temperature varies between 285 and 300 °F. The optimal temperature for SO_2 removal in a SDA is 10 to 15 °C below the saturation temperature to maximize the removal of SO_2. At approximately 15% moisture of Chena's flue gas, the saturation temperature would be around 88 °C (190 °F). This would cause wet solids to deposit on the absorber and downstream equipment. For spray dry systems, the temperature of the flue gas exiting the absorber must be 10 to 15 °C (20 to 50 °F) above the adiabatic saturation temperature.[4] The Healy plant inlet temperature is 300 °F and exists at 175 °F; however the O&M manual for the SDA references 185 °F as the outlet set point. Regardless, the long return duct run from the tower to the fabric filter would require reheating.to prevent moisture from condensing out of the gas. The reheating requirements will add to the increase in energy consumption from the control technology.

In a second option, Boiler 5 flue gas would be treated independently with a SDA system. For this option, the flue gas take-off point could be closer to the boiler, but the tower itself will still need to be located at a spot with available space approximately 100 to 200 ft away, and gas reheat would still be required as described for option 1. A separate spray tower for the combined flue gases from Boilers 1, 2, and 3 would have to be situated in the same area on the north side of the property as described above with ducting between 150 and 250 ft. This configuration is essentially the same as described in option 1 and therefore is not considered independently as an option.

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[4] Ibid (Air Pollution Control Technology Fact Sheet).

A third option would place the spray dryer tower after the fabric filter. This orientation would require a second fabric filter housing to be constructed at the facility. Based on an air-to-cloth ratio of 10 ft/min for lime[5], 0.39 lb/MMBtu SO_2 in the flue gas, a stoichiometric conversion from SO_2 to $CaSO_3$ (1.875), and a 75% removal efficiency, the filter area required of the secondary baghouse would be 25,000 ft^2. The current baghouse has a filter area of 61,000 ft^2 and a footprint of 35,035 ft^2 (not including the ducting and ID fans). Assuming the profile would be similar for the secondary baghouse, a footprint of 14,360 ft^2 would be required. Space is not available on Aurora's property for the installation of a second baghouse which would be about 40% the size of the current baghouse.

Existing PM Collection and Storage Equipment--A SDA placed upstream of the existing Chena fabric filter would have several negative operational impacts. First, the amount of additional PM generated and sent to the existing fabric filter could cause the existing filter system to clean more continuously. The baghouse cleans when the differential pressure drop between inlet and outlet reaches 6 inches water column. The baghouse currently cycles through cleaning about 24 times a day. Assuming 4% fly ash is generated at an average operating load of 220,000 ton/yr of coal (2,000 lb/hour fly ash), the increase in fly ash at the projected maximum coal input rate of 283,824 ton/yr (2,592 lb/hour fly ash) would cause the baghouse to cycle 31 times a day (24 cycles/day x 2,592 lb/hr ÷ 2000 lb/hr). The additional particulate generation could increase the ash load to the baghouse by 267 lb/hr (0.39 lb SO_2/MMBtu at 75% removal efficiency). The additional load would increase the baghouse daily cleaning cycle to 34. The additional cycling of the system would require an increase in electrical consumption and operational maintenance.

While the particle loading could be accommodated by the existing baghouse, it is unlikely that additional airflow from added control technologies could be accommodated through the baghouse at maximum load. A stoichiometric analysis of the combustion flue gas, with 7% oxygen yields 11.1 lb of exhaust/lb of coal. The density of the exhaust air

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[5] EPA. 2002. Air Pollution Cost Control Manual: Section 6, Particulate Matter Controls. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf. Research Triangle Park, North Carolina.

from the plant, based on average test data, is 0.048 lb/ft^3.[6] If a maximum projected heat input rate of 486 MMBtu/hr (283,824 ton/yr coal) were realized, the air flow through the baghouse would be 250,000 ft^3/min, which is the rated capacity of the baghouse. The stoichiometric analysis does not consider air infiltration which would increase the air flow to the baghouse beyond its capacity. Additional airflow needed for add-on control technologies would exceed the design air flow of the existing baghouse.

The duct reconstruction at the flue gas take-off point as well as the point where the treated flue gas is re-introduced to the fabric filter inlet also will require additional gas-handling equipment. Therefore, the additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance necessary to address potential plugging and filter replacement.

A take-off point after the existing fabric filter would alleviate the excessive PM loading issue. This orientation would require that a new outlet gas duct be retrofit onto the existing fabric filter housing to deliver the outlet gas to a second fabric filter. The existing filter vents through a roof monitor (also referred to as a monovent). In order to direct the fabric filter outlet gas to a downstream SDA system, one would need to open the top of the existing filter housing, weld new gas distribution plates to the outlet plenum, and construct a single gas outlet duct. This outlet duct would then be directed to the downstream SDA system, new fabric filter, and PM silo. The structural stability of the existing filter housing may be inadequate for handling the additional stress of the gas distribution components, in which case, extensive structural reinforcement would be needed. Construction of these items would demand more space than is available. As is clearly apparent by looking at Figure 1, the site has no extra space in which to build any such equipment for PM collection and storage. Additionally, operation of such a system orientation would increase the electric consumption at the facility. The average total electrical power consumption for the SDA system at the Healy Clean Coal

[6] Airflow Sciences Corporation. Chena PJFF Inlet Ductwork Flow Modeling. Fairbanks, Alaska. October 2015.

Project for their Healy Unit #2 during a performance test was 550.5 kW.[7] The Chena Power Plant baghouse power consumption is 460 kW. An SDA would potentially double the pollution control load of the plant and decrease the net sales of power approximately 2.4%.

Contamination of Collected Particulate--The ash constituent loading would change as a result of adding sorbents used in the process. This change could render the ash unsuitable for beneficial use as a fill material. Fly ash collected at Chena is beneficially used as a construction fill material. The addition of sorbents could compromise the leaching characteristics of the ash which is a metric to determine its suitability for beneficial structural fill. Without adequate testing, there is uncertainty as to the impact of the sorbents on the leaching characteristics of the ash. Use of an SDA system downstream of the exiting fabric filter could alleviate this issue if the sorbent byproducts were addressed separately from combustion ash.

Facility Space Limitations for Ancillary Equipment-- Regardless of whether a SDA is placed upstream or downstream of the existing fabric filter, the spatial requirement of the system and auxiliary equipment will be difficult to accommodate. A SDA system would employ lime, Trona, or sodium bicarbonate as the scrubbing reagent. Extensive preliminary engineering would need to be performed to define space requirements for the scrubber tower(s); raw reagent receiving areas, piping, conveyors, and storage tanks and silos, and reagent mills; as well as similar equipment for handling the solid waste material generated in the system. The GVEA Healy plant, in addition to the SDA vessel, houses conveyors, recycle surge bin (12-ft diameter), slurry feed tank (7.5-ft diameter), slurry mixing tank (10.5-ft diameter), mill classifier, and a storage silo for the sorbent.

Much of the equipment needed for an SDA system would be large items that occupy a substantial footprint. As can be seen in Figure 1, very little unused space exists at the facility. No space exists for an enclosed spray tower, and therefore a tower would need to be sited outdoors. No space exists between the combined boiler ducts and the fabric filter (as seen in Figure 1) to insert a spray tower. Because all of these duct runs are located

[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.

outdoors, maintaining the flue gas temperatures needed for the reaction and preventing moisture in the fabric filter will be expensive and difficult. Finally, as can be visualized by looking at Figure 1, the site does not have enough unused area to accommodate a dry material receiving operation and slurry preparation area. There is a likelihood that material receiving would have to occur on the north side of the Chena River. This would necessitate another river crossing which adds another layer of complexity to the process. Ultimately, the spatial considerations for the equipment would require a building to house the technology and heat to maintain the temperatures needed for the application. The parasitic load from electrical consumption and heating for the application would be substantial; at the least greater than 2.5% of current net generation.

1.3 DRY SORBENT INJECTION

In the utility industry, SO_2 may be removed by injecting a dry sorbent (limestone, Trona, or sodium bicarbonate are the common sorbents) into the combustion gases, typically above the burners or in the backpass before or after the air heater. Furnace DSI involves injection of the sorbent into the boiler system at a location downstream of the combustion zone through special injection ports. In DSI, the sorbent contacts the hot gas, decomposes, and reacts in suspension with SO_2 to form reaction products, such as calcium sulfate ($CaSO_4$), when using lime or limestone, or sodium sulfate (Na_2SO_4) when using Trona (sodium sesquicarbonate) or sodium bicarbonate. The reaction products, unreacted sorbent, and fly ash are removed at the PM control device (either an ESP or fabric filter) downstream from the boiler.

DSI has historically been used for reducing concentrations of hydrochloric acid (HCl), mercury, and sulfates (SO_3) from coal-fired boiler flue gas. Recently, DSI has seen greater use primarily as a system to comply with the Maximum Achievable Control Technology (MACT) requirements for boilers, aka, Boiler MACT. As operators began using DSI for HCl control in response to Boiler MACT, incidental removal of SO_2 was also being observed. SO_2 removal efficiencies of 30% to 70% have been reported for DSI in the utility industry when sorbent is injected and mixed at optimum conditions, and higher removals have been demonstrated in test/pilot operations. However these performance levels have yet to be widely demonstrated on a long-term continuous basis at permanent installations. For comparison, the Consent Decree between GVEA and the US EPA and the subsequent Minor Permit issued by the ADEC specified a 30-day SO_2 emission rate of no greater than 0.30 lb/MMBtu commencing

September 30, 2015 or 18 months after Healy Unit 2 first fired coal.[8] This emission rate represents a 23% reduction of average uncontrolled SO_2 emissions through the use of a DSI system.

In practice, the reaction chemistry of a DSI system is very straight forward. As a result, some level of SO_2 removal should be obtained when conditions exist that allow the reaction to take place. The performance of a DSI system for SO_2 removal is a function of several factors:

- Sorbent type
- Flue gas temperature at the injection location
- Sorbent particle size
- Sorbent injection rate, or Normalized Stoichiometric Ratio (NSR)
    - Extent of sorbent-to-gas mixing
    - Reaction residence time prior to the PM collection device
- PM control device type
- Flue gas properties
    - Concentrations of other acid gases competing with SO_2 reaction chemistry
    - Flow distribution and moisture content

Discussion of some of the more important aspects of DSI system performance is provided in the following paragraphs.

1.3.1 *Sorbent Type*

It is generally accepted that sodium-based sorbents (Trona and sodium bicarbonate) produce higher SO_2 removal rates than calcium-based sorbents (lime or limestone). This observation has been borne out by the operations at the Healy, AK coal-fired boiler facility. When first implemented, the DSI system at the Healy facility was based on limestone injection. After a period of operation, the limestone-based DSI system was replaced with a Trona-based system to improve performance. The Trona-based system was subsequently replaced with a sodium bicarbonate DSI system to further improve performance. As was the case at Healy, coal-fired boiler installations seem to be moving to use of the sodium sorbents to achieve SO_2 removal efficiencies of at least 40%. Therefore, no additional discussion of calcium sorbents is provided herein.

[8] Ibid (Technical Analysis Report).

1.3.2 *Flue Gas Temperature at the Injection Location*

Flue gas temperature will have a direct effect on reaction kinetics. A higher efficiency can be achieved when DSI is injected at a location where the flue gas temperature is approximately 500° F, and removal becomes less as the injection location is cooler or hotter. When a sorbent particle is introduced into a hot flue gas, it decomposes to sodium carbonate and the surface area of the particle increases. As reported in a recent Technical Report, the particle surface area begins to increase at 300° F (the minimum recommended sorbent injection temperature) and peaks at 500° F (the "optimum" temperature).[9] Above 500° F the particle structure begins to change and particle sintering may begin, effectively decreasing the activity of the particle. As the particle surface areas increases, a greater portion of the sorbent material is available to participate in the reaction with SO_2, thus producing an increased removal rate.

1.3.3 *Sorbent Particle Size*

Sorbent consumption and acid gas removal rates have been improved over the past several years with the understanding of the importance of uniform sorbent particle size and high sorbent surface areas. To effect these improvements, most DSI systems now employ in-line milling equipment for all sodium sorbents.

1.3.4 *Sorbent Injection Rate (or NSR)*

The NSR reflects the sorbent utilization rate, or the efficiency by which the injected sorbent is utilized in the SO_2 removal reaction. All else being equal, the SO_2 removal rate increases (up to an upper limit) as the NSR is increased. In addition to the particle size factor discussed above, sorbent-to-gas mixing and residence time prior to entering the PM control device will influence the NSR needed to achieve a desired removal rate. Poor mixing conditions and low residence (i.e., reaction) times will produce the situation where a greater NSR is needed to achieve the same level of performance as observed in a well-mixed, adequately timed duct system. A DSI cost model defines its typical NSR for milled Trona with an ESP as

[9] Dr. Sahu, Ranajit, Technical Report on Dry Sorbent Injection (DSI) and Its Applicability to TVA's Shawnee Fossil Plant, Commissioned by the Southern Alliance for Clean Energy, Knoxville, TN, April 2013.

1.40 (target removal is 50%), and its typical NSR for milled Trona with a fabric filter as 1.55 (target removal is 70%).[10] These NSR represent sorbent injection rates of 40% and 55% above the stoichiometric amount of Trona needed for the SO_2 reaction. When other than optimum conditions exist for DSI use (such as poor mixing or inadequate residence time), the NSR must be increased to account for less than optimum sorbent utilization. The actual performance of a DSI system can vary from 0% to 90% depending on the NSR and other operating characteristics.[11]

A separate operating issue has been observed when DSI systems operate with a high NSR. As the NSR increases, a brown nitrogen oxide (NOx) plume begins to be generated and emitted from the stack. This situation produces an undesirable environmental impact of using a DSI system.

1.3.5 PM Control Device Type

One of the more influential DSI system parameters is the PM collection system. This influence is important because the sorbent remains available to participate in the SO_2 reaction while in the ESP or fabric filter used to collect the PM in the flue gas. A system that employs a fabric filter will inherently achieve a greater SO_2 removal rate than one that employs an ESP because a dust cake that builds on the surface of the filter bags provides additional surface area upon which the SO_2 can react. Although studies on the effect of bag cleaning mechanisms could not be found, a pulse air jet bag cleaning system would appear to produce a lesser (secondary) SO_2 removal rate than a shaker system due to the fact that the pulse air system is designed to periodically completely break the dust cake from the cloth, as opposed a shaker cleaning system in which some remnant dust particles would remain on the surface and in the weave of the cloth after cleaning.

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[10] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology (Final report), prepared for Systems Research and Applications Corporation, March 2013.
[11] Ibid (Sargent & Lundy).

1.3.6 *Flue Gas Properties*

The ability of DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form HCl in the flue gas and consume a portion of the injected sorbent. Careful consideration of the chlorine content of the coal, therefore, is needed when sizing the system and defining the NSR.

Distribution of flow with the flue gas duct work is important for at least two reasons: 1) the distribution influences in-duct mixing, and 2) flow distribution may contribute to sorbent deposition within the duct or impaction and plating upon the walls. Many DSI equipment vendors offer Computational Fluid Dynamic (CFD) modeling of plant duct flows to predict and enhance sorbent distribution in flue gas, thereby maximizing performance and minimizing sorbent usage.

1.3.7 *Site-specific Considerations for Using DSI at Chena*

Two aspects of boiler operation at Chena are good for considering a DSI system: 1) the facility uses a fabric filter for PM control, which improves DSI performance by allowing for continued contact between SO_2 and sorbent, and 2) the flue gas temperature entering the fabric filter is approximately 300° F, which is near the minimum recommended temperature at the sorbent inject location. Some aspects of the Chena operation and site, however, are less than optimum for retrofitting a DSI system, and some of these aspects (i.e., constraints) are discussed below.

***Stoker Design*—** Many of the initial DSI systems were demonstrated on fluidized bed combustion units and employed sorbent injection into the boiler combustion zone. Unlike a fluidized bed combustor, the old traveling grate stokers used at Chena are not designed for suspension burning. Sorbent injected into the combustion zone in a stoker unit would settle onto the stoker coal bed and become unavailable for reaction. This would result in dead burning of the sorbent. For this reason, sorbent injection would need to occur outside of the combustion zone in downstream duct locations that are cooler than in the combustion zone. As noted above, however, adequate temperature exists in other duct locations to allow DSI use at Chena.

Alternative DSI System Orientations **—** Three basic DSI system orientations exist at Chena. Sorbent could either be injected into duct work for each individual boiler (four injection locations), a single injection location where all four duct systems converge just prior to entering the fabric filter, or at two locations—one for the large boiler and one for the three combined small boilers. The simplest of these options would be a single injection point. This option could, however, impact sorbent utilization (see NSR discussion below). Regardless of the selected orientation, a DSI system could be provided that employs a single sorbent receiving and storage area and associated conveying system with or without splitters to convey sorbent to more than one injection location. Assuming that the sorbent is milled in-line, immediately prior to injection, at least two sorbent mills would be needed for each injection location (one mill for use and one redundant mill). Therefore, between two and eight sorbent mills (depending on the number of injection points and ease of moving redundant equipment between injection points when needed) would be required depending on the DSI system orientation.

Factors Influencing NSR **—** The congested site layout will potentially adversely impact the amount of sorbent needed (i.e., NSR) to achieve reasonable reductions using DSI. Figure 1 previously showed the arrangement of flue gas duct work for Boiler 1, 2, and 3. Although not visible in Figure 1, these three duct systems combine with the flue gas duct work for Boiler 5 just prior to entering the fabric filter. If a single sorbent injection location is specified, this location would provide a short mixing zone with a low residence time prior to the fabric filter. Approximately 10 ft of duct is available between the location where the flue gas ducts converge and the combined gas enters the fabric filter. Gas velocities between 55 ft per second (ft/s) and 75 ft/s exist at this location, indicating that the sorbent and flue gas would be afforded only between 0.1 and 0.2 seconds of mixing/residence time prior to entering the fabric filter housing. The GVEA Healy plant's Unit #1 (305 MMBtu/hr boiler) has a 100-ft run prior to the baghouse from the injection point. Assuming GVEA maintains similar duct velocity as Chena, the GVEA DSI system operates with a reaction time of 1 or 2 seconds of mixing prior to entering the fabric filter housing. The mixing zone and residence time at the Chena plant would be very short (10 times less) in comparison and will potentially require additional sorbent be injected to achieve any sort of SO_2 removal. This will, in turn, reduce the cost effectiveness of a DSI system (i.e., increase the operating cost and reduce the removal rate).

Sorbent injection into individual boiler duct will eliminate the short mixing zone and residence time, but this equipment orientation may also adversely impact NSR. The flue gas from each boiler goes through several turns (up to seven) prior to entering the fabric filter housing. While this duct orientation yields good mixing, it may also promote particle deposition and plating on to the inside of the duct work, thereby causing some of the injected sorbent to be wasted and unavailable for reaction.

Existing PM Collection and Storage Equipment — Similar to the issues introduced when discussing SDA, additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance.

Also, potential changes to the constituent loading and leaching characteristics of the ash due to sorbent use could render the ash unsuitable for beneficial use fill material. Aurora currently provides its collected ash to developers in the area for beneficial use as a fill material. The incorporation of sorbent to the ash could alter the properties of the ash such that it no longer meets the metric used to evaluate its benefit. If the ash from the Chena plant were to be treated as a waste product, significant disposal costs would be realized through either coal ash landfill development or tipping fees at the municipal solid waste landfill.

Facility Space Limitations — A DSI system is rather simple and requires lesser space for equipment than does a SDA system. Eielson Air Force Base (EAFB) recently installed new 120,000 lb/hr steam boilers which were designed with DSI to mitigate sulfate emissions. EAFB uses sodium bicarbonate as the sorbent, which they receive via rail from Solvay Chemical in Wyoming. The system includes two silos with storage capacity of 518 tons each for the sorbent. Each silo is 37 ft tall with a diameter of 21 ft and a 70 inch cone. The silos each hold a volume of 16,777 ft^3. EAFB's current rate of sorbent utilization is 1 lb of sorbent/1,600 lb of steam. At that rate, Aurora could expect a maximum use of 220 lb of sorbent/hr (350,000 lb steam/hr). The location of the injection point is at the outlet breaching of the boiler and the temperature of the flue gas at that point is 450°F. As previously discussed, 500°F at the injection point is optimal. While the silos do not occupy an extremely large area, the only available area on the Chena site would be in the northwest corner of the property. An adequate space exists in the northwest portion of the Chena site, but space for truck traffic to deliver the sorbent is extremely limited and may prevent actual truck movement in this area of the facility. Sorbent receiving would likely be sited north of the Chena River along with the coal receiving facilities. Sorbent would have to be received by rail or truck and conveyed across the river to storage silos on the south side of the river.

1.4 REVIEW OF SO_2 BACT DATABASE

The RACT/BACT/LAER (RBLC) Clearinghouse was searched again for this addendum (an original search was conducted and reported in the original BACT report) to identify similar sources with SO_2 BACT determinations within the past 10 years. The RBLC Clearinghouse lists 23 facilities with large (i.e., greater than 250 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations and two facilities with small (i.e., less than 100 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations. Table 1 summarizes the projects in the database search that are pertinent to the Chena Power Plant BACT Analysis. One additional facility is included, the Healy Power Plant, but was not identified in the RBLC search. When looking at reported performance at existing operations, one must acknowledge that the level of control claimed at existing facilities using SDA and DSI or as reported in the Clearinghouse database may not have actually been demonstrated by the facility and may not be achievable at the Chena facility. Additionally, other systems may have been installed that are not yet included in the RBLC Clearinghouse.

Ten of the 23 determinations for large boilers were for SDA and/or DSI systems, and the range of control reported for these determinations was:

- SDA: 0.06 to 0.10 lb/MMBtu (five facilities)
- DSI: 0.035 to 0.3 lb/MMBtu (four facilities)
- Combination SDA/DSI: 0.055 to 0.075 lb/MMBtu (three facilities)

Table 1. Summary of SO_2 BACT Permit Reviews

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection(1)	Circulating Dry Scrubber	
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, >250 MMBtu/hr Pollutant Name = SO_2	AR-0094	John W. Turk Power Plant	11/5/2008	6,000 MMBtu/hr PRB sub-bituminous pulverized coal (PC) boiler							X			0.08 lb/MMBtu, 30-day average (0.065 lb/MMBtu when burning coal <= 0.45% by weight sulfur content. (PSD and Case-by-Case MACT permit decision.)
	AZ-0055	Navajo Generating Station	2/6/2012	3, 7,725 MMBtu/hr PC boilers						X				
	CA-1206	Stockton Cogen Company	9/16/2011	730 MMBtu/hr coal-fired circulating fluidized bed (CFB) boiler								X		70% removal (3-hr average)
	IA-0091	Ottumwa Generating Station	2/27/2007	6,370 MMBtu/hr coal-fired Boiler #1		X								1.2 lb/MMBtu, 3-hr rolling average (Wet FGD rejected at $29,797/ton (2007 dollar basis).)
	KY-0100	J.K. Smith Generating Station	4/9/2010	3,000 MMBtu/hr CFB boilers CFB1 and CFB2							X	X		0.075 lb/MMBtu, 30-day average (Based on PRB coal - 0.54% S; bituminous coal - 1.58% S; and 1.4 lb SO_2/MMBtu at wet FGD inlet.) Permit terminated due to legal challenge.
	MI-0389	Karn Weadock Generating Complex	12/29/2009	8,190 MMBtu/hr PRB coal or 50/50 blend PC boiler (fuel to meet 1.4 lb SO_2/MMBtu at FGD inlet)		X		X						0.06 lb/MMBtu, 30-day rolling average
	MI-0399	Detroit Edison--Monroe	12/21/2010	7,624 MMBtu/hr coal-fired Boiler Units 1, 2, 3 and 4			X							0.107 lb/MMBtu each, 24-hr rolling average
	MI-0400	Wolverine Power	6/29/2011	2, 3,030 MMBtu/hr, petcoke/coal-fired CFB Boilers (CFB1 & CFB2) (Excluding Startup & Shutdown)							X			0.06 lb/MMBtu, 30-day rolling average; excluding startup & shutdown
	MO-0077	Norborne Power Plant	2/22/2008	Supercritical PC boiler with steam turbine generator with a nominal net electric output of 689 MW					X					
	ND-0024	Spiritwood Station	9/14/2007	1,280 MMBtu/hr lignite coal-fired atmospheric CFB boiler							X	X		0.06 lb/MMBtu, 30-day rolling average; 98.7% removal for worst case 30-day lignite; 98.8% removal for worst case 24-hr lignite

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	
	OH-0310	American Municipal Power Generating Station	10/8/2009	2, 5,191 MMBtu/hr, PC boilers			X							0.15 lb/MMBtu, 30-day rolling average; 0.184 lb/MMBtu, 24-hr rolling average; 0.2400 lb/MMBtu, 3-hr average Admin permit mod 10/09 to add Case-by-Case MACT for Boilers
	OH-0314	Smart Papers Holdings, LLC	1/31/2008	420 MMBtu/hr coal-fired pulverized dry bottom boiler and 249 MMBtu/hr coal-fired spreader stoker coal-fired boiler										1.7 lb/MMBtu
	OK-0118	Hugo Generating Station	2/9/2007	750 MW coal-fired steam EGU boiler (HU-Unit 2)			X							0.065 lb/MMBtu, 30-day rolling average
	PA-0257	Sunnyside Ethanol, LLC	5/7/2007	496.8 MMBtu/hr coal-fired CFB boiler					X			X		0.2 lb/MMBtu, 30-day rolling average
	TX-0554	Coleto Creek Unit 2	5/3/2010	6,670 MMBtu/hr PRB coal-fired Boiler Unit 2							X			0.06 lb/MMBtu, 30-day rolling average
	TX-0577	White Stallion Energy Center	12/16/2010	3,300 MMBtu/hr coal & pet coke-fired CFB Boiler							X			0.114 lb/MMBtu pet coke, 30-day rolling average; 0.086 lb/MMBtu, pet coke 12-mo rolling average; 0.063 lb/MMBtu coal, 30-day and 12-mo rolling average
	TX-0585	Tenaska Trailblazer Energy Center	12/30/2010	8,307 MMBtu/hr sub-bituminous coal-fired boiler			X							0.06 lb/MMBtu, 30-day rolling average
	TX-0593	Texas Clean Energy Project	12/28/2010	400 MW PRB coal-fired Integrated Gasification Combined Cycle power plant	X									10 ppm sulfur in syngas
	TX-0601	Gibbons Creek Steam Electric Station	10/28/2011	5,060 MMBtu/hr coal-fired boiler			X							1.2 lb/MMBtu
	UT-0070	Bonanza Power Plant Waste Coal Fired Unit	8/30/2007	2, 1,445 MMBtu/hr waste coal/bituminous blend-fired CFB boiler							X	X		0.055 lb/MMBtu, 30-day rolling average
	VA-0311	Virginia City Hybrid Energy Center	6/30/2008	2, 3,132 MMBtu/hr coal and coal refuse-fired CFB boilers (Sulfur content of coal/coal refuse to CFB boilers not to exceed 2.28% as-fired and 1.5% on annual basis)								X		0.035 lb/MMBtu, 3-hr average; 0.029 lb/MMBtu, 24-hr average; 0.022 lb/MMBtu, 30-day rolling average
	WY-0063	Wygen 3	2/5/2007	1,300 MMBtu/hr sub-bituminous coal-fired PC boiler					X					0.09 lb/MMBtu, 12-mo rolling average
	WY-0064	Dry Fork Station	10/15/2007	Coal-fired PC Boiler (ES1-01)									X	0.07 lb/MMBtu, 12-mo rolling average

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description									Emission Limit
					Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	
	N/A (not in RBLC)	Golden Valley Electric Association – Healy Power Plant (HPP)	11/19/2012 Consent Decree and 4/14/2014 Minor Permit	2, existing PC-fired steam generators: a 25 MW Foster-Wheeler Boiler (Unit #1) and a 50 MW TRW Entrained Combustion System PC-fired steam generator (Unit #2).								X		Unit #1 (DSI system): - Improve existing DSI system no later than 9/30/2015 or 18 months after Unit #2 first fires coal after 11/19/2012 whichever is later. - After 1/1/2016, SO_2 emission limit of 0.30 lb/MMBtu, 30-day rolling average
											X			Unit #2 (SDA system): - SO_2 emission limit of 0.10 lb/MMBtu, 30-day rolling average
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, <100 MMBtu/hr Pollutant Name = SO_2	OH-0315	New Steel International Inc., Haverhill	5/6/2008	6, 60 MMBtu/hr waste heat, PC boilers							X			0.1760 lb/MMBtu as a rolling 3-hour average The facility is non-attainment for $PM_{2.5}$ and PSD for PM, PM_{10}, CO, NOx, SO_2, and VOC. A production rate restriction on the electric arc furnaces was requested to keel lead below PSD and Title V thresholds. PM_{10} was used as the limit in the permit. However, since $PM_{2.5}$ was used for all LAER determinations the limits were entered under $PM_{2.5}$ instead.
	VA-0309	Georgia Pacific Wood Products - Jarratt	5/15/2008	86.6 MMBtu/hr coal-fired Keeler Boiler	X	X								

1. Limestone Injection presumed to be equivalent to DSI.

It should be noted that SDA or DSI were required only on circulating fluidized bed (CFB) or pulverized coal (PC) boilers. In contrast, the Chena boilers are stoker boilers for which the boiler operation is quite different than a CFB or PC boiler and present unique retrofit challenges. In addition, the sizes of these units range from approximately 2 to 25 times larger than the large Chena boiler.

One small boiler was identified with an SDA system required to meet 0.1760 lb SO_2/MMBtu.

1.5 SUMMARY OF TECHNICAL FEASIBILITY

Regardless of the achievable level of control afforded by a dry scrubbing system, this control technology (SDA and DSI) is considered technically feasible for controlling SO_2 emissions from coal fired boilers, and the RBLC identifies several in use on larger coal-fired boilers. A detailed evaluation of constraints posed by site-specific factors, however, is needed before either specific technology can be considered feasible for use at the Chena facility. These detailed site-specific evaluations/design factors are beyond the scope of the current BACT analysis.

In the absence of a detailed control system design for Chena, a level of 0.10 lb SO_2/MMBtu was selected for SDA for the BACT analysis, which is comparable with that required for the Healy Unit #2. This represents a 74% reduction from Aurora's actual SO_2 emission rate of 0.39 lb/MMBtu. Independent discussions with SDA equipment vendors, however, indicate that vendors do not like to select design removal rates above 0.12 lb/MMBtu (equivalent to 70% removal). The Healy performance requirement is considered most relevant to Chena because the boilers at Healy are of similar size to Chena's and the coal feed is the same.

Selection of an appropriate design basis for a DSI system for Chena is much less straight forward. One primary reason is that DSI systems reported in the RBLC Clearinghouse are for lime injection into fluidized bed combustors, which are very different that the Chena stokers. A DSI system performance level of 0.30 lb SO_2/MMBtu has been specified for the Healy DSI system, representing a 23% reduction from average uncontrolled SO_2 emissions. Interestingly, the Technical Analysis Report (TAR) for Healy Permit AQ0173MSS0, which requires the facility to "improve" the DSI system performance currently on Healy Unit No. 1, specifies the improved emission rate of 0.30 lb SO_2/MMBtu. This statement in the TAR, therefore, suggests that the original Healy DSI system was achieving less than 23% reduction of SO_2. Literature, however, commonly reports a lower end of DSI system performance at 40%, and discussions with vendors indicate that this level of removal (without knowing the exact coal used) is generally achievable using DSI. Because of discrepancies in reported DSI system performance, therefore, one could easily define DSI system performance when using Usibelli coal as less than 23% removal. For the current assessment, DSI system performance was selected to be between 0.23 and 0.30 lb SO_2/MMBtu (i.e., between 23% and 40% removal).

2 ECONOMIC EVALUATION OF SO_2 CONTROL OPTIONS

Despite the technical challenges described in Section 1 associated with installation of SDA or DSI at the Chena Power Plant, an economic evaluation was prepared for each technology under the assumption that these challenges could possibly be mitigated during a detailed design.

2.1 SDA ECONOMIC EVALUATION

Capital and operating costs associated with the installation of a SDA system are based on cost estimating procedures developed by U.S. EPA in the Coal Utility Environmental Cost (CUECost) tool. The CUECost tool is an Excel workbook (an interrelated set of spreadsheets) that produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control systems installed on coal-fired power plants, including those to control emissions of SO_2. The SO_2 emission control technologies currently in the workbook include: limestone FGD system with forced oxidation (i.e., wet scrubber) and lime spray drying FGD system (i.e., dry scrubber).

The wet scrubber portion of the CUECost tool was used in the original BACT Analysis. The spray drying portion of the tool was used for this addendum and was used for two scenarios – control of the combined boiler exhaust and control of the large boiler exhaust only. The CUECost tool included the following site-specific information:

- Net Plant Heat Rate (Btu/kWhr) = 11,571
- Retrofit Factor = 2.0 (difficult)
- Coal ultimate and proximate analysis data and ash analysis data obtained from http://www.usibelli.com/Coal-data.php
- Site specific SO_2 emission rate
  - Combined exhaust = 0.39 lb SO_2/MMBtu
  - Large boiler only = 0.32 lb SO_2/MMBtu
- Reagent price is $215/ton delivered
- Cost basis = 2015
- SO_2 removal required = 74 percent
- Annual SO_2 removed based on full load at 8,760 hr/year

All other values used were default values.

No attempt was made to incorporate location-specific cost adjustment factors into the CUECost tool.

The cost-effectiveness of the SO_2 control system is calculated in the CUECost tool by dividing the total annual cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 2 presents a summary of the CUECost inputs and calculation summary for the lime spray dryer scrubber.

Table 5 presents the cost effectiveness of the SDA technology (as well as the DSI technology discussed in the next section).

2.2 *DSI ECONOMIC EVALUATION*

Capital and operating costs associated with the installation of a DSI system are based on a DSI cost model developed by Sargent & Lundy and referred to as the IPM Model.[12] In developing the IPM Model, the authors reviewed cost data for several DSI systems and developed a relationship for the capital costs based on the sorbent feed rate. The Total Project Cost output by the IPM Model includes the base installed cost, the fixed operating and maintenance (O&M) cost, and the variable O&M cost. The base installed cost includes:

- All equipment
- Installation
- Buildings
- Foundations
- Electrical
- Retrofit difficulty factor
- Engineering and construction management

The Model uses 2012 pricing. Escalation is not included in the estimate.

[12] Ibid (Sargent & Lundy).

Table 2. CUECost Input and Calculation Summary for SDA

CUECost			
Coal Utility Environmental Cost			
Version 1, November 25, 1998 (revised 2-9-00 as CUECost3.xls)			
APC Technology Choices			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
FGD Process	Integer	2	2
(1 = LSFO, 2 = LSD)			
Particulate Control	Integer	1	1
(1 = Fabric Filter, 2 = ESP)			
INPUTS			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
General Plant Technical Inputs			
Location - State	Abbrev.	AK	AK
MW Equivalent of Flue Gas to Control System	MW	142.4	74.6
Net Plant Heat Rate	Btu/kWhr	11,571	11,571
Plant Capacity Factor	%	65%	65%
Total Air Downstream of Economizer	%	120%	120%
Air Heater Leakage	%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350
Inlet Air Temperature	°F	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013
Ash Split:			
Fly Ash	%	40%	40%
Bottom Ash	%	60%	60%
Seismic Zone	Integer	1	1
Retrofit Factor	Integer	2	2
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No
Economic Inputs			
Cost Basis -Year Dollars	Year	2015	2015
Sevice Life (levelization period)	Years	10	10
Inflation Rate	%	3%	3%
After Tax Discount Rate (current $'s)	%	9%	9%
AFDC Rate (current $'s)	%	11%	11%
First-year Carrying Charge (current $'s)	%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%
Sales Tax	%	6%	6%
Escalation Rates:			
Consumables (O&M)	%	3%	3%
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	578.4	578.4
If "No" input escalation rate.	%	3%	3%
Construction Labor Rate	$/hr	$60	$60
Prime Contractor's Markup	%	3%	3%
Operating Labor Rate	$/hr	$63	$63
Power Cost	Mills/kWh	25	25
Steam Cost	$/1000 lbs	3.5	3.5

Note: 'MW Equivalent of Flue Gas to Control System' is heat input capacity converted to MW.

Lime Spray Dryer (LSD) Inputs			
SO2 Removal Required **(removal required to reach 0.1 lb/MMBtu)**	%	74%	69%
Adiabatic Saturation Temperature	°F	127	127
Flue Gas Approach to Saturation	°F	20	20
Spray Dryer Outlet Temperature	°F	147	147
Reagent Feed Ratio	Factor	0.76	0.70
(Mole CaO / Mole Inlet SO2)			
Recycle Rate	Factor	30	30
(lb recycle / lb lime feed)			
Recycle Slurry Solids Concentration	Wt. %	35%	35%
Number of Absorbers	Integer	1	1
(Max. Capacity = 300 MW per spray dryer)			
Absorber Material	Integer	1	1
(1 = alloy, 2 = RLCS)			
Spray Dryer Pressure Drop	in. H2O	5	5
Reagent Bulk Storage	Days	60	60
Reagent Cost (delivered)	$/ton	$215	$215
Dry Waste Disposal Cost	$/ton	$30	$30
Maintenance Factors by Area (% of Installed Cost)			
Reagent Feed	%	5%	5%
SO2 Removal	%	5%	5%
Flue Gas Handling	%	5%	5%
Waste / Byproduct	%	5%	5%
Support Equipment	%	5%	5%
Contingency by Area (% of Installed Cost)			
Reagent Feed	%	20%	20%
SO2 Removal	%	20%	20%
Flue Gas Handling	%	20%	20%
Waste / Byproduct	%	20%	20%
Support Equipment	%	20%	20%
General Facilities by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%
Engineering Fees by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%

SUMMARY OF COSTS			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
APC Technologies			
SO2 Control		LSD	LSD
		Combined Exhaust	**Large Boiler only**
SO2 Control Costs		**LSD**	**LSD**
Total Capital Requirement (TCR)	$	$74,161,357	$62,173,057
	$/kW	$521	$833
First Year Costs			
Fixed O&M	$	$3,709,418	$2,767,988
	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$	$415,100	$203,435
	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$	$16,537,983	$13,864,592
	$/kW-Yr	116.14	185.85
	Mills/kWH	20.40	32.64
	$/ton SO2 removed	$41,415.5	$86,909.6
TOTAL	$	$20,662,501	$16,836,015
	$/kW-Yr	145.10	225.68
	Mills/kWH	25.48	39.64
	$/ton SO2 removed	$51,744	$105,536
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	30.11	42.89
	Mills/kWH	5.29	7.53
	$/ton SO2 removed	$10,737.6	$20,056.1
Variable O&M	$/kW-Yr	3.37	3.15
	Mills/kWH	0.59	0.55
	$/ton SO2 removed	$1,201.6	$1,474.0
Fixed Charges	$/kW-Yr	88.01	140.85
	Mills/kWH	15.46	24.74
	$/ton SO2 removed	$31,386.6	$65,864.3
TOTAL	$/kW-Yr	121.49	186.89
	Mills/kWH	21.34	32.82
	$/ton SO2 removed	$43,325.8	$87,394.4
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$/kW-Yr	60.93	97.51
	Mills/kWH	15.20	24.32
	$/ton SO2 removed	$30,863.7	$64,767.1
TOTAL	$/kW-Yr	89.90	137.34
	Mills/kWH	20.29	31.32
	$/ton SO2 removed	$41,192.6	$83,393.3

The O&M cost includes:

- Fixed
  - Operating labor for the DSI system (two operators needed)
  - Maintenance materials and labor
  - Administrative labor
- Variable
  - Sorbent use
  - Waste production and disposable cost
  - Additional required power

The IPM Model used for this addendum included two equipment orientations: 1) sorbent injection into the combined boiler exhaust just immediately prior to the fabric filter, and 2) sorbent injection into the individual exhaust from the large boiler near the combustion zone. The IPM Model tool included the following site-specific information:

- Gross heat input
  - Combined = 486 MMBtu/hr
  - Large boiler = 255 MMBtu/hr
  - Small boilers = 77 MMBtu/hr each
- Retrofit Factor = 2.0 (difficult)
- Location Adjustment Factor = 2.2 (for Fairbanks, Alaska)
  - The location adjustment factor (LAF) is applied to the base installed cost and reflects the average statistical differences in normal labor, material, and equipment costs for similar facilities built in different geographical locations. The factor also makes allowances for weather, seismic, climatic, normal labor availability, labor productivity, life support/mobilization, and contractor's overhead and profit conditions. The factor does not reflect abnormal differences due to unique site consideration, such as historical preservation.[13] (The CUECost model has no way to accommodate this factor, and LAF was not applied for SDA.)
- Site specific SO_2 emission rate
  - 0.39 lb/MMBtu (combined)
  - 0.32 lb/MMBtu (large boiler only)
  - 0.49 lb/MMBtu (each small boiler)

[13] Programming Cost Estimates for Military Construction, UFC3-370-01, 6 June 2011.

- Cost Basis = 2015
- SO_2 removal required = 40 percent
- Annual SO_2 removed based on full load at 8,760 hr/year
- Minimum Normalized Stoichiometric Ratio (NSR) = 1.5 (to account for less than optimum mixing and residence time in the combined orientation; deposition in the individual orientation; and breaking the filter cake in all orientations.
- Sorbent price based on delivered price paid by Healy in 2015/2016

All other values used were default values.

The cost-effectiveness of the SO_2 control system is calculated in the IPM Model by dividing the total annualized operating cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 3 and Table 4 present summaries of the IPM Model inputs and cost effectiveness calculation summaries for the DSI system.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	142.4	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.39	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	486,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for less than optimum mixing and residence time in the combined orientation and breaking the filter cake in all orientations)
Trona Feed Rate	M	(ton/hr)	0.34	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.246	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.90	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.05	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\/2/, UFC 3-701-01, Change 8, July 2015.
IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.				

Capital Cost Calculation (2012 dollars)			Comments
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty			
Base Module (BM) ($)	=	$ 26,915,857	Base DSI module includes all equipment from unloading to injection
Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284)			
Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)			
Total Project Cost			
A1 = 5% of BM	=	$ 1,345,793	Engineering and construction management costs
A2 = 5% of BM	=	$ 1,345,793	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM	=	$ 1,345,793	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	$ 30,953,236	Capital, engineering, and construction costst subtotal
B1 = 5% of CECC	=	$ 1,547,662	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	$ 32,500,898	Total project cost without AFUDC
B2 = 0% of (CECC + B1)	=	0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$ 32,500,898**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust (continued)

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	1.84	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	0.95	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.07	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**2.85**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	1.08	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	0.40	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$	0.045	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**1.53**	
Indirect Annual Costs				
Overhead (80% of total operation and maintenance labor)	=	$	324,909	
Administrative charges (2% of total capital investment)	=	$	650,018	
Insurance (1% of total capital investment)	=	$	325,009	
Property tax (1% of total capital investment)	=	$	325,009	
Capital recovery	=	$	5,289,521	
(16.275% of total capital investment: 10 yr at 10% interest)				
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,914,466**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,227,624**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2015 (cost year of review)	=		578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$**	**9,129,760**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		830	
SO_2 REMOVAL EFFICIENCY, %	=		40	
TOTAL SO_2 REMOVED, tons	=		332	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**27,493**	

Table 4. Annualized Cost Summary for DSI for the Large Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	74.6	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.32	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	255,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for deposition in the individual orientation)
Trona Feed Rate	M	(ton/hr)	0.147	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.106	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.47	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.04	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\/2/, UFC 3-701-01, Change 8, July 2015.
IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.				

Capital Cost Calculation (2012 dollars)			Comments
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty			
Base Module (BM) ($)	=	$ 21,186,595	Base DSI module includes all equipment from unloading to injection
Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284)			
Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)			
Total Project Cost			
A1 = 5% of BM	=	$ 1,059,330	Engineering and construction management costs
A2 = 5% of BM	=	$ 1,059,330	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM	=	$ 1,059,330	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	$ 24,364,585	Capital, engineering, and construction costst subtotal
B1 = 5% of CECC	=	$ 1,218,229	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	$ 25,582,814	Total project cost without AFUDC
B2 = 0% of (CECC + B1)	=	0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$ 25,582,814**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	3.51	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	1.42	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**5.06**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	0.889	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	0.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$	0.037	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**1.31**	
Indirect Annual Costs				
Overhead (80% of total operation and maintenance labor)	=	$	301,717	
Administrative charges (2% of total capital investment)	=	$	511,656	
Insurance (1% of total capital investment)	=	$	255,828	
Property tax (1% of total capital investment)	=	$	255,828	
Capital recovery	=	$	4,163,603	
(16.275% of total capital investment: 10 yr at 10% interest)				
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**5,488,633**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**6,723,906**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2015 (cost year of review)	=		578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$**	**6,652,596**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		357	
SO_2 REMOVAL EFFICIENCY, %	=		40	
TOTAL SO_2 REMOVED, tons	=		143	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**46,534**	

Table 5 presents a summary of the cost effectiveness of all SO_2 control options considered, including the wet scrubber considered in the original BACT Analysis. As seen in the individual cost model spreadsheets, the model-derived cost-effectiveness values are based on the potential SO_2 emissions from the Chena boilers. The combined SO_2 emission rate from all four boilers is equal to 814.5 tons/yr (potential) and 700 tons/yr (actual). The value for actual emissions is based 1.9 tons SO_2 per day as specified in the State Implementation Plan (SIP). Therefore, to derive cost-effectiveness values based on actual expected SO_2 reductions, the cost-effectiveness values output by the cost models were adjusted by the ratio of actual emissions to potential emissions.

Table 5 presents the calculated SO_2 removal cost effectiveness on both a potential emission reduction and actual emission reduction basis. These values are not considered cost effective for the retrofit options at Chena Power Plant.

Table 5. Summary of Cost Effectiveness of SO_2 Control Options

Rank	Control Option	Control Orientation	Cost Effectiveness ($ per year/ ton per year removed		Expected SO_2 Emission Rate (lb/MMBtu)
			Potential	Actual	
1	Low sulfur coal	combined exhaust	(already used)		0.39
2	Dry scrubber – DSI	combined exhaust	27,493	31,990	0.23 (40% removal)
3	Dry scrubber – SDA	combined exhaust	41,193	47,931	0.10 (74% removal)
4	Dry scrubber – DSI	large boiler only	46,534	54,146	0.19 (40% removal)
5	Wet scrubber	combined exhaust	75,672	88,050	0.20 (50% removal)
6	Dry scrubber – SDA	large boiler only	83,393	97,034	0.10 (69% removal)

3 DISCUSSION OF SITE-SPECIFIC TECHNICAL, ENVIRONMENTAL, AND ENERGY ASPECTS OF DRY SCRUBBING TECHNOLOGY USE AT CHENA POWER PLANT

3.1 SUMMARY OF TECHNICAL FEATURES AND CHALLENGES

Table 6 presents a summary of some technical features of SDA and DSI technologies evaluated herein and some challenges associated with their potential use at Chena. Section 1 of this report identified several SDA and DSI applications for coal-fired boilers. The quality of the information varies considerably, and the information acquired was used as best as possible to hypothesize performance expectations from each evaluated technology. Nonetheless, no true assurances exist that the evaluated technologies will actually perform as stated when applied to the Chena facility. While the technical concepts are valid, demonstration of the technology employed as retrofit technology on units and equipment orientations such as those observed at the Chena facility cannot reliably be predicted, thus raising doubts over the accuracy of technology transfer, particularly for sorbent injection. Perhaps the best example of this uncertainty can be found when reviewing the history of the DSI system operation at the Healy Power Plant in Healy, AK. The subject of a Consent Decree, Healy was ordered to "improve" the DSI system in use on Unit No. 1 to achieve a controlled SO_2 emission rate of 0.30 lb/MMBtu. Even with extensive testing under the US Department of Energy Clean Coal program, this marginal mandated performance level is indicative of technological uncertainties associated with retrofit technology applied to control coal-fired boiler emissions.

Coupled with the technological uncertainties associated with these technologies applied as a retrofit solution are other factors that obscure the practicality of applying retrofit dry scrubber technology at the Chena facility. One of these factors, the economics of the technologies, was discussed in detail in Section 2 of this report and led to the observation that application of SDA or DSI at Chena was not a cost-effective means to reduce SO_2 emissions. Other factors, discussed in the following sections, include:

- Facility location limitations
- Environmental considerations
- Energy considerations

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant

Factor	Spray Dry Absorber Technology	Dry Sorbent Injection Technology
Demonstrated use under conditions similar to Chena Plant	1. Spray dry absorber technology is available and used to reduce SO_2 emissions from coal-fired boiler flue gas streams. 2.The U.S. EPA's air pollution control cost manual indicates that SDA technology can be reduce SO_2 by 50% up to over 90%. Finding a suitable outlet for the particulate captured in the fabric filter following dry scrubbing is an important consideration to the feasibility of this option.	1. Dry sorbent injection is becoming more prevalent for reducing acid gas concentrations in coal-fired boiler flue gas streams. 2. Although DSI technology is discussed in the industry, the only DSI systems presented in the RBLC Clearinghouse are lime/limestone injection systems into fluidized bed combustors. No DSI systems are listed when the boiler is a stoker, as at Chena. 3. Sorbent injection into the duct work downstream of the coal combustion zone is also becoming more prevalent in the industry, as reported by equipment vendors. No such systems, however, are presented in the RBLC Clearinghouse.
Technical considerations	1. Depending on equipment orientation, a SDA system would lower the flue gas temperature, which could then cause plugging of the downstream fabric filter. 2. A SDA system placed upstream of the fabric filters would potentially contaminate the ash and cause the loss of a useable by-product. 3. A SDA system would require gas reheating to prevent plugging in the fabric filter, thus increasing station service load. 4. The temperature of water used to prepare the lime slurry can impact the hydrated lime reactivity. Adequate facilities must be included (indoors) to prevent issues associated with slurry preparation, delivery, and use. 5.The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved.	1. The existing duct work at Chena is very complicated and winding. Sorbent injection into a section of combined flue gas would have less than optimum mixing and less than 0.2 seconds of residence time prior to entering the fabric filter. These two situations will increase the sorbent consumption rate by reducing sorbent utilization. 2. Sorbent injection into the large boiler alone would provide adequate mixing time, but the flue gas would continue through seven turns in which sorbent loss through deposition on the interior duct work could occur, thus increasing sorbent consumption. 3.The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved. 4. Use of sorbent materials may render the collected ash no longer suitable for use as a fill material. The current beneficial use of collected ash as a fill material would have to be replaced with landfill disposal of the collected PM.

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

<table>
<tr><th>Factor</th><th>Spray Dry Absorber Technology</th><th>Dry Sorbent Injection Technology</th></tr>
<tr><td>Structural considerations</td><td colspan="2">1. The structural stability of the existing ash silo would have to be improved prior to storing any additional PM.
2. Any system placed downstream of the existing fabric filter would necessitate major structural modifications to the existing filter housing to alter the exhaust configuration of the treated flue gas from a monovent, roof monitor arrangement to a gas duct section that delivers gas to the dry scrubber system.</td></tr>
<tr><td rowspan="2">Operational considerations</td><td>1. A SDA system would require additional fans to overcome the increased distance needed to convey the flue gas. The entire air emissions control systems would need to be rebalanced as well. The existing system potentially may not meet design requirements for baghouse air flow.</td><td>1. The history of DSI operation at the Healy facility of GVEA has been anything but stable. The need to retrofit the system on two different occasions draws into question the reliability of the DSI technology.</td></tr>
<tr><td colspan="2">2. The Chena boilers are reaching the end of their useful lives. A life extension study commissioned by Aurora determined that Chena operations could be extended to the year 2030 with expenditure of significant capital. An add-on emission control program aimed at reducing SO_2 emissions over a 10-year period represents an unwise capital expenditure at this time.
3. The U.S. Corps of Engineers estimates that additional construction and operating costs are incurred for projects in Alaska when compared to mainland US. These considerations are difficult to assess in an analysis such as this BACT.
4. .A dry scrubber placed at the outlet of the existing fabric filter would require re-heating the exhaust gases to an optimum temperature; this would reduce steam available for power generation, heating, or station service. A second fabric filter would be then needed to remove the particulate matter formed during scrubbing.
5. The Trona or sodium bicarbonate reagent mill would be required to produce a uniformly-sized sorbent particle prior to use.
6. Reagent receiving and processing would likely require construction of building(s) north of the Chena River and a conveyor over the Chena River. Raw and processed materials would need to be conveyed over relatively long distances.
7. The PM collected in the fabric filter may become a waste product and no longer able to be used as fill.
8. The PM collected in the fabric filter may require pre-treatment prior to disposal as a solid waste.</td></tr>
</table>

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

<table>
<tr><th>Factor</th><th>Spray Dry Absorber Technology</th><th>Dry Sorbent Injection Technology</th></tr>
<tr><td rowspan="2">Availability of infrastructure and space for equipment</td><td colspan="2">1. A minimal amount of open space is available at the Chena facility to house additional equipment needed to support dry scrubbing technology.</td></tr>
<tr><td>2. The location of a reagent storage area for an SDA system will need to be determined.
3. A preliminary estimate, based on a similarly-sized facility in Colorado, is that the spray tower will need to be at least 40 ft in diameter. The only available space at the Chena facility for this tower would be in the northwest corner of the facility.
4. The flue gas would need to be rerouted approximately 250 ft to the location of the spray tower and then return another 250 ft to the inlet of the fabric filter. This gas rerouting would be needed whether the SDA was oriented as a combined flue gas treatment system or one devoted only to the large boiler. Space for additional fans would then be needed.
5. Availability of land area for the reagent silos and slurry preparation is uncertain.</td><td>2. The short duct run after combination of flue gases makes sorbent inject extremely difficult and leads to poor mixing and short residence time.
3. An area of approximately 50 ft x 50 ft would be needed to house the sorbent receiving and storage area. This area would need to be located in the northwest corner of the facility. This area of the facility has minimal truck traffic at present, and routine deliveries of sorbent by truck would disrupt the normal operations in the area.</td></tr>
</table>

These factors are discussed in the following sections. These factors also were discussed in the original BACT Analysis, and some of the discussion presented below is taken from the original analysis.

3.2 *LOCATION CONSIDERATIONS*

Several issues related to space limitations at Chena were presented in Section 1 or this report. An important aspect of operating on an older, small industrial site is the ability to actually place additional equipment needed to operate add-on control equipment. The SDA and DSI technologies require installation of silos for reagent storage, facilities for preparing the sorbent for treatment of the flue gas, and the technology itself must be erected in available space. The congested nature of the existing Chena Power Plant site is such that the retrofit installation costs are likely to be higher than those estimated and presented in the cost tables provided earlier. Additionally, lack of available space on site could make installation of additional equipment completely infeasible. This limitation would not be completely understood prior to preliminary design of any identified system.

Each of the identified SO_2 technologies also requires routine delivery of reagents to operate the system and will require removal of residues produced by the process. The congested nature of the Chena facility makes on-site truck traffic patterns somewhat problematic. Additionally, Fairbanks is approximately 400 miles from Anchorage, which is a logical location for origination of raw materials. Delivery of necessary sorbents over potentially icy roadways may interrupt raw material deliveries to the point where interruptions in plant operations could occur. The hazardous driving conditions also may cause the transportation costs for raw materials or process equipment to be greater than presented in the cost sheets, thereby causing the cost effectiveness of control to be a larger value than calculated.

Climate considerations factor into the BACT evaluation in two ways: 1) climate causes the costs to become inflated due to the need for additional insulation, heated vessels, and heat tracing, and 2) climate affects the ability of the precursor emissions from the Chena Power Plant to react in the atmosphere and form $PM_{2.5}$. However, no site factors are included in the SDA control cost calculations. Thus, the SDA SO_2 control costs, while already extremely high, may be underestimated. The atmospheric factor, which may limit atmospheric reaction rates, is briefly discussed in the next section on environmental considerations.

3.3 ENVIRONMENTAL CONSIDERATIONS

Environmental factors must be considered in a BACT evaluation. With respect to nonattainment BACT, precursor control options that are determined to be economically feasible may not yield the desired objective of improving $PM_{2.5}$ air quality. (This statement is true even though none of the control options evaluated in this BACT evaluation were found to be economically feasible.) A rash conclusion to implement a (economically feasible) precursor control as BACT may in fact produce insignificant environmental benefits and at the same time produce adverse energy or environmental impacts. The environmental topics are discussed below, and energy considerations in the following section. Much of the following discussion was presented in the original BACT Analysis.

The rationale for ensuring that benefits of a precursor control option are indeed real and significant is founded in the Clean Air Act (CAA). CAA section 189(e) explicitly requires that the control requirements applicable for major stationary sources of direct $PM_{2.5}$ emissions must also apply to major stationary sources of $PM_{2.5}$ precursors, unless the state provides a demonstration that emissions of a particular precursor from major stationary sources do not contribute significantly to levels that exceed the standard in the nonattainment area of concern. Thus, the statute generally requires control of all $PM_{2.5}$ precursors in a nonattainment area, but it provides an express exception applicable to major stationary sources in such areas if an appropriate demonstration is made.[14]

A key conclusion derived by looking at the chemical mass balance (CMB) evaluations for PM filters collected in the Fairbanks North Star Borough (FNSB) is that control of Chena Power Plant $PM_{2.5}$ precursors will not provide significant reduction of ambient $PM_{2.5}$. This conclusion can easily be validated by looking solely at the wood smoke contribution and comparing it to the $PM_{2.5}$ standard. As is seen on many episode days, the standard is exceeded solely due to contribution from wood smoke, while the impact of sulfates on episode days is minor.

Although the CMB results included in the SIP provide some insight into establishing source contributions in the FNSB, no straightforward procedures can be used to determine a specific source contribution to ambient $PM_{2.5}$ concentrations and, by extension, the air quality improvements in $PM_{2.5}$ air quality should one or more control measures be implemented at the Chena Power Plant. Because no one procedure answers every question one may have, a variety of procedures are often employed. This is a key issue that relates the magnitude of reductions in daily precursor emissions to commensurate reductions in $PM_{2.5}$ concentrations. In many cases, indirect procedures must be employed to estimate air quality benefits resulting from installation of precursor emission controls. For example, DSI (the SO_2 control option identified herein that has the best cost-effectiveness) was estimated to be able to achieve a 40 percent reduction in SO_2 emissions from the Chena Power Plant boilers. As provided in the background information for the ADEC SIP, on average, Chena Power Plant boilers emitted 1.9 ton/day of SO_2 in 2015 on days when the $PM_{2.5}$ standard was exceeded.[15] Thus, application of DSI at Chena would result in an average SO_2 reduction of 0.76 ton/day.

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[14] Federal Register, Volume 81, page 58091, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

[15] ADEC, Amendments to: State Air Quality Control Plan Volume II: Analysis of Problems, Control Actions; Section III: Area-wide Pollutant Control Program; D: Particulate Matter; 5: Fairbanks North Star Borough $PM_{2.5}$ Control Plan, Section 5.06, page III.D.5.6-27.

This reduction represents only 6.2 percent of the estimated NOx and SO_2 nonattainment area-wide emissions, respectively, estimated to occur on $PM_{2.5}$ episode days in 2008.

ADEC included CMB results in the SIP to provide some insight into establishing source contributions in the FNSB.[16] The CMB analysis estimated a maximum sulfate contribution of 28.8 micrograms per cubic meter ($\mu g/m^3$) (at most) in downtown Fairbanks on high $PM_{2.5}$ concentration days between 2005 and 2013. Assuming that all of the precursor emission reductions noted above for Chena Power Plant culminate in the same level of ambient $PM_{2.5}$ reductions, use of DSI technologies at Chena would benefit ambient air quality in downtown Fairbanks by only 1.8 $\mu g/m^3$ for sulfates (i.e., 28.8 μg sulfate/m^3 times 6.2 percent reduction in daily SO_2 emissions). The improvements on an average basis would be about half these amounts.

Another environmental factor impacting the true effectiveness of a control option is the atmospheric reaction process that leads to conversion of precursor emissions to $PM_{2.5}$. Three major issues must be considered when evaluating the Chena Power Plant's contribution to $PM_{2.5}$ levels within the FNSB air basin: 1) precursor reaction chemistry in arctic wintertime conditions when exceedances of the $PM_{2.5}$ NAAQS occur, 2) possible increases in nitrate formation as ammonium ions become available, and 3) transport and dispersion of the Chena Power Plant boiler stack plume above and beyond the capped inversion layer that encapsulates the FNSB air basin causing accumulation of ground-level $PM_{2.5}$ within the air basin.

Formation of secondary $PM_{2.5}$ depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity; and the interactions of precursors with preexisting particles and with cloud or fog droplets. The relative contribution to ambient $PM_{2.5}$ concentrations from each precursor pollutant varies by

[16] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-66.

climatological area. The relative effect of reducing emissions of these pollutants is also highly variable.[17]

Sulfates are typically formed in the atmosphere by formation of sulfuric acid from SO_2 that subsequently reacts with ammonia to form ammonium sulfate. There are three different pathways for the transformation of SO_2 to sulfuric acid[18]:

1. Gaseous SO_2 can be oxidized by the hydroxyl radical (OH) to create sulfuric acid. This gaseous SO_2 oxidation reaction occurs slowly and only in the daytime.

2. SO_2 can dissolve in cloud water (or fog or rainwater), and there it can be oxidized to sulfuric acid by a variety of oxidants, or through catalysis by transition metals such as manganese or iron. If ammonia is present and taken up by the water droplet, then ammonium sulfate will form as a precipitate in the water droplet.

3. SO_2 can be oxidized in reactions in the particle-bound water in the aerosol particles themselves. This process takes place continuously, but only produces appreciable sulfate in alkaline (dust, sea salt) coarse particles.

These climatological conditions that are conducive to sulfate formation from transformation of SO_2 are not consistent with the conditions that typically generate high $PM_{2.5}$ concentrations in the FNSB.

Some researchers have reported an increase in nitrate formation associated with ambient SO_2 reductions. This association is strongest in low temperature areas of low humidity and exists because additional ammonium ions will become available for reaction with NOx emissions.[19] Although the net $PM_{2.5}$ concentration will likely be lower after SO_2 reductions, a linear reduction of the ambient $PM_{2.5}$ concentration is not

[17] Federal Register, Volume 73, page 28325, May 16, 2008, 40 CFR Parts 51 and 52, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$).

[18] NARSTO (2004) Particulate Matter Science for Policy Makers: A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 184287 5.

[19] Ibid (NARSTO).

expected, and less $PM_{2.5}$ reduction will be observed than expected because of the increase in the nitrate concentration.

An issue also arises in the FNSB related to the dispersion of precursor emissions from the Chena Power Plant boiler stack and the ability of the dispersed emissions to actually impact the ambient air quality monitors. It has been observed, and it is reasonable to expect, that the boiler stack plume is carried above the winter inversion layer. As such, transport of the precursor pollutants occurs above the inversion layer, where the concentrations of the pollutants can be transported and dispersed by the stronger aloft winds. In addition, the Fairbanks $PM_{2.5}$ Source Apportionment Research Study[20] concluded that dominant aloft wind direction during $PM_{2.5}$ episodes is from the northeast, which would transport the Chena Power Plant emissions away from the ambient air quality monitors located in downtown Fairbanks and North Pole. Figure 2 presents a photograph showing the Chena Power Plant boiler stack exhaust plume height well above the inversion layer. The original BACT Analysis presented an evaluation of Chena coal consumption on high $PM_{2.5}$ concentration days between 2013 and 2015 and revealed a very poor (or no) correlation between Chena Power Plant coal consumption and observed ambient $PM_{2.5}$ levels. This poor correlation is believed to be due to plume entrapment above the wintertime inversion layer.

The poor correlations reported in the original BACT Analysis indicate that changes in Chena Power Plant emissions do not explain the majority of the changes in ambient $PM_{2.5}$ levels. Because the Chena Power Plant emissions are not seemingly influencing the ambient $PM_{2.5}$ concentrations to any significant extent, the ambient levels must be the result of other emission sources in the FNSB.

[20] The Fairbanks, Alaska $PM_{2.5}$ Source Apportionment Research Study Winters 2005/2006-2012/2013, and Summer 2012; Final Report, Amendments 6 and 7, December 23, 2013, Tony J. Ward, Ph.D., University of Montana – Missoula , Center for Environmental Health Sciences.

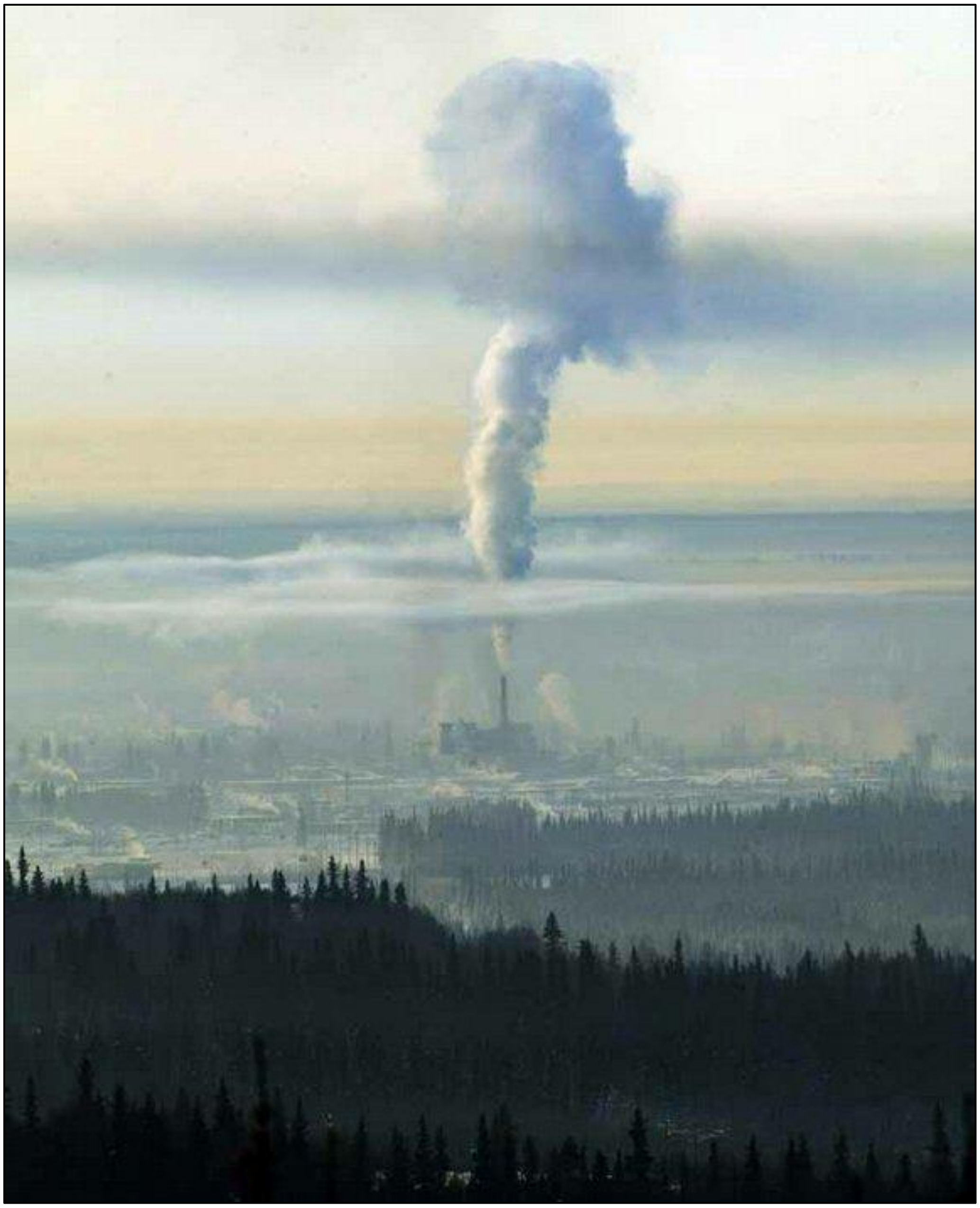

Figure 2. Chena Power Plant exhaust plume.[21]

[21] The exhaust from the Aurora Energy power plant breaks through an inversion layer as seen from the Hagelbarger Road pullout off the Steese Highway. Photo credits: Frank DeGenova, January 30, 2008, http://marcvaldez.blogspot.com/2008/05/wintertime-smokestack-plumes-in.html, accessed December 22, 2017.

This observation can be further illustrated using the following example for the highest $PM_{2.5}$ day (early January) in 2015 at downtown Fairbanks monitors when Chena Power Plant coal consumption was at its greatest rate (2.2 million pounds/day). If this was during one of the coldest days, then the Chena Power Plant impact at ground level would have been less than on other days because: 1) the buoyancy term for the Chena Power Plant boiler plume would be at its greatest because the temperature differential between stack and ambient air temperatures would have been greatest, and 2) the momentum term for the boiler plume would also have been at its greatest because the exhaust gas flow rate would be greater than at lesser coal combustion rates. Because the impact of Chena Power Plant emissions would likely have been less on this episode day than other days, the $PM_{2.5}$ mass on the filters in question would had to have been contributed by other sources in the FNSB.

To summarize these environmental considerations related to photochemistry and precursor transport within the FNSB, the U.S. EPA makes the following corroborating points:

> "Major stationary sources with elevated stacks emit most of their precursors into the extremely stable atmosphere present during wintertime pollution events. Only a fraction of the elevated plumes returns to ground level in the FNSB where air quality monitors are located and much less than might be expected in most parts of the lower 48 states."[22]

In conclusion, and as noted earlier herein, use of DSI technologies at Chena is estimated to benefit ambient $PM_{2.5}$ air quality in downtown Fairbanks by only 1.8 $\mu g/m^3$ at the most due to reduction of ambient sulfates (i.e., 28.8 μg sulfate/m^3 times 6.28 percent reduction in daily SO_2 emissions). The actual improvement will likely be less due to the environmental considerations noted herein. The maximum estimated sulfate improvements in $PM_{2.5}$ air quality presented here are only slightly above the U.S. EPA-recommended 24-hour significant level of 1.3 $\mu g/m^3$ as presented in the recent Draft Precursor Guidance and could actually be less than the significant level. This reduction would possibly be accompanied by other increases in fuel combustion emissions, production

[22] Federal Register, Volume 82, page 9043, February 2, 2017, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

of a brown NOx cloud in the Chena plant stack, and elimination of the beneficial use of fly ash collected at the plant as fill material. These observations indicate that the environmental benefit of installing SO_2 controls at Chena Power Plant will produce no noticeable improvement in ambient $PM_{2.5}$ air quality and may produce negative associated environmental impacts.

3.4 ENERGY CONSIDERATIONS

Retrofit BACT as a means to reduce the pollutant load in an air basin must necessarily look at the effect that employing BACT on a specific source would have on other sources in the air basin and whether this effect would negatively impact the air quality improvement that is presumed to occur when BACT is employed. The original BACT Analysis presented a detailed discussion of energy considerations arises from the use of add-on air pollution control equipment. The reader is referred to that document for additional information regarding energy considerations for additional fuel and electricity consumption.

3.5 SUMMARY OF ENVIRONMENTAL AND ENERGY CONSIDERATIONS

The environmental considerations associated with installation of SO_2 controls on the Chena Power Plant produce uncertain assurances that any improvement in FNSB air quality will result. In fact, the data suggest that insignificant environmental improvements at best could occur. The energy considerations point to a likely lack of an air quality benefit in FNSB in the event that SO_2 controls are implemented at Chena Power Plant. In fact, such implementation could actually increase the air pollutant load in FNSB from sources more likely to produce a $PM_{2.5}$ ambient impact than Chena Power Plant.

4 *ANALYSIS OF ASPECTS RELATED TO BACT*

The supplemental information presented herein supports and enhances the SO_2 BACT determination presented in the original BACT Analysis. The previous sections of this supplement analyzed the several aspects that must be considered in a BACT determination, those being technical feasibility, economics, environment, and energy. This analysis yielded the following findings:

1. The technical feasibility of employing add-on SO_2 controls at Chena is highly questionable due to lack of available space at the facility for the equipment needed to scrub the flue gas as well as raw material receiving and processing equipment. Furthermore, the degree of control afforded by SDA and DSI technology is highly variable and difficult to define for conditions existing at Chena.

2. The economic analysis shows that use of SDA or DSI technology for SO_2 control is does not make economic sense as a retrofit option at Chena Power Plant.

3. The environmental considerations demonstrated that no significant ambient $PM_{2.5}$ improvement would be obtained by requiring SO_2 controls on Chena Power Plant. ADEC also recognizes that controlling direct $PM_{2.5}$ emissions (such as from wood stoves) is 13 times more effective at reducing ambient $PM_{2.5}$ concentrations than controlling precursor air pollutants that produce secondary $PM_{2.5}$. Furthermore, the actual ambient $PM_{2.5}$ benefit that can be achieved by reducing SO_2 emissions is extremely uncertain and difficult to calculate.

4. From an energy standpoint, installing an add-on SO_2 control device would increase the parasitic load at the Chena Power Plant. Loss of this energy output would require supplemental energy consumption at other sources within the FNSB or acquired through the grid from Anchorage to compensate for this parasitic load. This supplemental energy consumption at other sources may actually produce an increase in direct $PM_{2.5}$ emissions if the lost capacity were to be offset by fuel consumption for sources such as wood-burning stoves or oil-fired boilers, which tend to emit more direct $PM_{2.5}$ than Chena Power Plant, and at lower elevations. Furthermore, ADEC has already concluded, based on CMB

evaluations of PM filters in the FNSB, that these lower level sources are the more significant contributors to ambient $PM_{2.5}$ concentrations. Thus, the energy impacts of requiring SO_2 controls on Chena Power Plant could potentially have the exact opposite effect as desired and produce increases in ambient $PM_{2.5}$ concentrations in the FNSB.

4.1 DETERMINATION OF BACT FOR SO_2

Alaska coal has very low sulfur content, and uncontrolled sulfur emissions are four times lower than at a plant burning "low sulfur coal" in the lower 48 states.[23] The result is that the cost-effectiveness of SO_2 control technologies is poorer in Alaska than the lower 48 states. Current SO_2 emission rates from the Chena Power Plant are comparable to those identified as BACT in the most recent BACT determinations included in the RBLC database.

Therefore, as concluded in the original BACT Analysis, BACT for SO_2 emissions from Chena Power Plant is determined to be the continued use of low-sulfur coal.

[23] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-78.

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation of the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry injection or spray dry system. It further states that the installation of such technologies would

[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering DSI. However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please see comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control

efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

8. Good Combustion Practices – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

10. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).

11. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

12. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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Return Receipt Requested

September 13, 2018

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Second request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by November 1, 2018

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to Serious Non-Attainment Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measures (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

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

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the Chena Power Plant for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Aurora to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Aurora review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP which ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

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

Sincerely,

BY DIR

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Chena Power Plant BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin/EPA Region 10
Dan Brown/EPA Region 10
Zach Hedgpeth/EPA Region 10

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

<u>Precursor Demonstration</u>

1. <u>Ammonia Precursor Demonstration</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. <u>Sulfur Dioxide Precursor Description</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

<u>BACM (and BACT), MSM</u>

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. <u>BACM/BACT and MSM: Separate Analyses</u> - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. <u>Selection of Measures and Technologies</u> - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***<u>all</u>*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. <u>Technological Feasibility</u> - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the “General” comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure “that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources.” We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion “not eligible for consideration as BACM” is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
  - Measure R1, page 63: Natural gas fired kiln or regional kiln.
  - Measure R12, page 71: Replace uncertified stoves in rental units.
  - Measure R17, page 75: Ban use of wood stoves
  - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
  - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
  - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
   a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
   b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as “community burden” (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98^{th} percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in "emission inventory" versus "emissions inventory".

Page 1: "CAA" to "Clean Air Act" for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1's calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the "winter season" inventory as the "seasonal" inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, "results in extremely high heating energy demand per square foot experienced in no other location in the lower-48."

Page 9: Please change "Violations" to "Exceedances." Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add "No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.", to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., "downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear "For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a "base" demand typically met by cleaner home heating oil when ambient temperatures get colder."

Page 19: Remove "Where appropriate,". All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove “com”

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add “threshold” after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change “has decided” to “decided.”

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding “… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value” to the sentence that starts “The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing “slightly” and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption "These restrictions shall not apply during a power failure." should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for "Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, "did not know if the rule had worked well" needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists "none" under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

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 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

<u>Bicarbonate Storage</u>

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.

<u>Scope of Supply</u>

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: <u>$4,900,000</u>
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
300 ft
Google Earth
© 2018 Google

STANLEYCONSULTANTS, Inc

8000 South Chester Street › Suite 500 › Centennial, CO 80112
303.799.6806 › stanleyconsultants.com

October 30, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Preliminary Opinion of Probable Cost for Addition of Dry Sorbent Injection

David,

This letter serves to document the preliminary results of our opinion of probable cost for the installation of a Dry Sorbent Injection (DSI) System at the Aurora Energy Chena Plant for the control of Sulfur Dioxide (SO_2) emissions.

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 report to the Alaska Department of Environmental Conservation (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 report, ADEC conducted their own analysis and presented their results as a Preliminary BACT Determination in March of 2018. The results developed by ADEC as a part of their analysis were significantly different from the results presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy has hired Stanley Consultants to develop a site-specific, third-party estimate of the costs to install SO_2 emissions control equipment on the four operating boilers at the Chena Combined Heat and Power Plant near downtown Fairbanks. Stanley Consultants will also provide an estimated sorbent consumption rate and a cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, ERM, will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a Dollars/Tons of SO_2 removed basis.

This letter serves to document the preliminary Opinion of Probable Cost results so that Aurora Energy can submit a response to the BACT Determination ahead of a November 1, 2018 deadline. The information included herein relates only to the installation of a DSI system on the existing boilers. All performance information, quantities, and costs are preliminary and are

subject to revision as the cost estimate is refined and finalized. Additional clarifications as to the basis of the cost estimate and the anticipated performance are included below.

Design Basis

Boiler Performance and Flue Gas

Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates from the previous reports were utilized to determine equipment sizes and required sorbent feed rates

Dry Sorbent Unloading, Storage, Preparation, and Injection System

Equipment and piping costs for the Dry Sorbent Injection 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 the emissions from burning Healy coal in stoker-type boilers. The BACT proposal includes:

- 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 is sufficient for four 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.
- 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 equipment or systems that are required for proper operation of the DSI system, but was not included in the BACT proposal have been included separately in the cost estimate. This includes:

- Piping between the sorbent preparation building and the injection lance on each flue
- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse
- Electrical feeds and equipment required to support the BACT equipment
- 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 – Adjacent to the unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment – Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building – Adjacent to the existing baghouse

See the attached sketch for additional information on the proposed equipment locations and interconnecting piping.

Opinion of Probable Cost

Based on the information above, the current estimate of probable cost is as follows:

Total Installed Cost: $20.682MM

Sorbent Cost: $550/Ton, Delivered

Reference the attached spreadsheet for additional information relating to the equipment and construction costs used. Total installed costs include probable costs for engineering, procurement and construction of the DSI system. It also includes mobilization and indirect contractor costs such as bonding, overhead, and profit. Finally, the Total Installed Cost includes an escalation factor to account for inflation and other cost increases over the construction period.

Clarifications

- The estimated accuracy of this Opinion of Probable Costs is +50% and -30%. The accuracy is expected to improve as the cost estimate is refined.
- 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 degrees 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 degrees 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 costs included in this estimate are based on the best information that we have been able to obtain to-date. The refinement of existing costs or the inclusion of additional direct or indirect costs may be determined to be necessary as the preliminary design develops.
- Sorbent pricing information provided by BACT in their equipment proposal was supplied by the sorbent vendor based on a proposal 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 we have available today.

Conclusion

The preliminary Opinion of Probable Cost presented in this letter is our current best estimate for the costs associated with the procurement and installation of a DSI system at the Chena Combined Heat and Power Plant. The estimate attempts to account for many of the site-specific factors that may negatively impact the actual capital costs including, plant configuration, site layout, seismic considerations, existing infrastructure, and local construction cost factors.

We hope the information presented in this letter meets your immediate needs and we look forward to providing you with a final Opinion of Probable Costs along with supporting documentation in the near future.

Thank you for the opportunity to assist Aurora Energy in this matter.

Sincerely,

John Solan
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Attachments: DSI Equipment Layout Sketch

Opinion of Probable Cost Tabulation

Adopted November 19, 2019

Stanley Consultants INC.		Rev. 0	Job No. 28709.01.00	Page No.	1
			Subject	Aurora Energy Chena - Dry Sorbent Injection	
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 10/29/2018		Opinion of Probable Cost	
Checked by	J. Solan	Date 10/29/2018			
Approved by	C. Spooner	Date 10/30/2018	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	$1,880,200.00	$1,880,200
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	$6,370,000.00	$6,370,000
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	$238.00	$71,400
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$239.00	$74,090
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$239.00	$66,920
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$239.00	$47,800
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	$14,169,111
				Mobilization & Demobilization - 5%	$708,456
				Bond - 2.5%	$354,228
				Contractor Overhead - 10%	$1,416,911
				Contractor Profit - 10%	$1,416,911
				Total Construction Cost	$18,065,617
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$736,199
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,802,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,682,000**

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.

STANLEYCONSULTANTS, Inc

8000 South Chester Street › Suite 500 › Centennial, CO 80112
303.799.6806 › stanleyconsultants.com

October 30, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Preliminary Opinion of Probable Cost for Addition of Dry Sorbent Injection

David,

This letter serves to document the preliminary results of our opinion of probable cost for the installation of a Dry Sorbent Injection (DSI) System at the Aurora Energy Chena Plant for the control of Sulfur Dioxide (SO_2) emissions.

Background

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Project Scope

Given the disparity in the results of the analyses, Aurora Energy has hired Stanley Consultants to develop a site-specific, third-party estimate of the costs to install SO_2 emissions control equipment on the four operating boilers at the Chena Combined Heat and Power Plant near downtown Fairbanks. Stanley Consultants will also provide an estimated sorbent consumption rate and a cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, ERM, will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a Dollars/Tons of SO_2 removed basis.

This letter serves to document the preliminary Opinion of Probable Cost results so that Aurora Energy can submit a response to the BACT Determination ahead of a November 1, 2018 deadline. The information included herein relates only to the installation of a DSI system on the existing boilers. All performance information, quantities, and costs are preliminary and are

subject to revision as the cost estimate is refined and finalized. Additional clarifications as to the basis of the cost estimate and the anticipated performance are included below.

Design Basis

Boiler Performance and Flue Gas

Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates from the previous reports were utilized to determine equipment sizes and required sorbent feed rates

Dry Sorbent Unloading, Storage, Preparation, and Injection System

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- 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.
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- 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.
- 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 equipment or systems that are required for proper operation of the DSI system, but was not included in the BACT proposal have been included separately in the cost estimate. This includes:

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- 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 – Adjacent to the unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment – Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building – Adjacent to the existing baghouse

See the attached sketch for additional information on the proposed equipment locations and interconnecting piping.

Opinion of Probable Cost

Based on the information above, the current estimate of probable cost is as follows:

Total Installed Cost: $20.682MM

Sorbent Cost: $550/Ton, Delivered

Reference the attached spreadsheet for additional information relating to the equipment and construction costs used. Total installed costs include probable costs for engineering, procurement and construction of the DSI system. It also includes mobilization and indirect contractor costs such as bonding, overhead, and profit. Finally, the Total Installed Cost includes an escalation factor to account for inflation and other cost increases over the construction period.

Clarifications

- The estimated accuracy of this Opinion of Probable Costs is +50% and -30%. The accuracy is expected to improve as the cost estimate is refined.
- 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 degrees 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 degrees 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 costs included in this estimate are based on the best information that we have been able to obtain to-date. The refinement of existing costs or the inclusion of additional direct or indirect costs may be determined to be necessary as the preliminary design develops.
- Sorbent pricing information provided by BACT in their equipment proposal was supplied by the sorbent vendor based on a proposal 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 we have available today.

Conclusion

The preliminary Opinion of Probable Cost presented in this letter is our current best estimate for the costs associated with the procurement and installation of a DSI system at the Chena Combined Heat and Power Plant. The estimate attempts to account for many of the site-specific factors that may negatively impact the actual capital costs including, plant configuration, site layout, seismic considerations, existing infrastructure, and local construction cost factors.

We hope the information presented in this letter meets your immediate needs and we look forward to providing you with a final Opinion of Probable Costs along with supporting documentation in the near future.

Thank you for the opportunity to assist Aurora Energy in this matter.

Sincerely,

John Solan
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Attachments: DSI Equipment Layout Sketch

Opinion of Probable Cost Tabulation

AURORA ENERGY

November 1, 2018

Alaska Department of Environmental Conservation
Division of Air Quality
ATTN: Director
410 Wiloughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: Second Request for Additional Information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant.

Dear Ms. Koch,

Thank you for the opportunity to provide additional information to better characterize Aurora's operations for the Best Available Control Technology (BACT) Analysis which will be a part of the Serious Area State Implementation Plan.

The following is being provided in response to the information request letter dated September 13, 2018. The ADEC letter included an enclosure with twelve comments for which additional information was requested. Each comment is summarized below followed by a response from Aurora. The information is being submitted to the ADEC by November 1, 2018 as requested.

1. Alternative Fuel Source - Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.

   Response: There are no other economically viable coal options for Aurora. Usibelli Coal Mine is the state's only operating coal mine.

2. Low Excess Air (LEA) and Overfire Air (OFA) - Evaluate these technically feasible control technologies using EPA's top down approach.

   Response: Aurora's BACT analysis dated March of 2017, Section 2.3.2, references the use of combustion controls, including OFA and LEA. The BACT analysis concludes that the Unit 5 (EU 7) is already equipped with OFA, LEA (i.e., oxygen trim system), and air preheaters. It is stated within the BACT that Units 1, 2, and 3 (EU 4-6) have OFA and air preheaters. Although the air preheater ductwork is installed, the preheaters have been removed from operation. The current

configuration of the traveling-grate boilers as installed, includes a 'partial' LEA (i.e., oxygen trim system). The fuel feed rate and oxygen for Boiler Units 1-3 (EU 4-6) are manually adjusted and tuned daily. The traveling-grate boilers have a knife gate which sets the bed thickness and the air-to-fuel ratio is manually adjusted to accommodate the boiler's performance. Once adjusted, the fuel-to-air ratio is maintained automatically.

3. Additional SO_2 Control Technologies - The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO2 removal, and therefore must be included in the analysis.

   Response: - An addendum to the initial BACT submittal was provided to the State on December 22, 2017. This addendum included a substantive analysis of Spray Dry Absorbers (SDA) and Dry Sorbent Injection (DSI) technologies.

4. BACT Limits - Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   Response: Statements concerning applicable standards under 40 CFR Parts 60 (New Source Performance Standards—NSPS) and 61 (National Emission Standards for Hazardous Air Pollutants—NESHAP) are not relevant to the Chena boilers. The NESHAP do not regulate criteria air pollutants such as SO_2, and therefore, no SO_2 floor can be defined by any NESHAP. Furthermore, the Chena boilers are not subject to NSPS and therefore are not required to achieve the NSPS standard. In any case, the NSPS SO_2 emission limit of 1.2 lb/MM Btu (for units less than 75 MM Btu/hr) is achieved in the small boilers (the percent reduction is not a requirement for units less than 75 MM Btu/hr).

   An NSPS or NESHAP standard must be considered as the floor for BACT only when a source is subject to one of the standards. In that case, a source must achieve compliance with the NSPS or NESHAP, and a less stringent emission limit cannot be considered BACT. As noted in a July 28, 1987 memo by Gary McCutchen, then Chief of the New Source Review Section of the US EPA:

   > "Since an ***applicable*** NSPS must always be met, it provides a legal "floor" for the BACT, which cannot be less stringent." (emphasis added). This statement implies that a source must first be subject to an NSPS for the standard to be considered the BACT floor.

   The Chena plant operates four coal-fired boilers: three at 76.8 MM Btu/hr (22.5 megawatt, MW) heat input and one at 254.7 MM Btu/hr (74.6 MW) heat input. If newly-constructed today, the three smaller units would be subject to an NSPS Subpart Dc limit of 1.2 lb SO_2/MM Btu, and the larger unit would be subject to an NSPS Subpart Da limit of 0.15 lb SO_2/MM Btu. On a Btu-weighted average basis, the overall NSPS limit would be 0.64 lb SO_2/MM Btu. The Chena boilers

currently combust low-sulfur coal, with emissions of 0.39 lb SO_2/MM Btu from the combined exhaust. This overall emission rate represents a 39% reduction from NSPS limits if the Chena boilers had been built today.

Regardless of the NSPS applicability to the Chena boilers, the history of rulemaking for small industrial, commercial, and institutional (ICI) boilers provides valuable insight into the definition of BACT for SO_2 from these units. The three smaller units, if constructed today, would be subject to NSPS Subpart Dc for small ICI boilers. As defined in the standard, ICI units smaller than 22 MW (75 MM Btu/hr) heat input are not subject to a percent reduction requirement in NSPS and instead may achieve compliance with NSPS through the use of low-sulfur fuel. The rationale for this "exemption" is provided in the preamble to the proposed rule (54 *Federal Register* (FR) 24806, June 9, 1989) and the Background Information Document for the Promulgated Standards. As discussed in the Background Document:

> "Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable....Imposing these high (capital and annualized) costs for the units (those less than 22 MW) was considered to be unreasonable when compared to the increase in emission reduction achievable be the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less."

The passage presented above is the basis for the US EPA's definition of BACT for small ICI boilers less than 22 MW. This analysis therefore defines BACT for such units as an emission rate equal to or greater than 1.2 lb SO_2/MM Btu. In the proposed rule, US EPA further states that compliance with this NSPS limit/ BACT emission rate for units smaller than 22 MW (75 MM Btu/hr) can be achieved through use of low-sulfur fuels (see 54 FR 24793). For all practical purposes, the three smaller boilers at the Chena plant fall into this category, and therefore BACT is defined as an emission limit of 1.2 lb SO_2/MM Btu, achieved through combustion of low-sulfur coal. Furthermore, as illustrated above, the four boilers at the Chena plant collectively operate with an actual SO_2 emission level that is 39 percent less than the levels that would be required if all of the units were subject to NSPS.

5. Retrofit Costs - Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

   Response: The BACT cost analysis employed a retrofit factor of 2.0. The basis for this factor was the EPA Air Pollution Control Cost Manual, Sixth Edition. As discussed in the Cost Manual:

   > "To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the

> cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst....The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. Even at detailed cost level (± 5 percent accuracy), vendors will not be able to fully assess the uncertainty associated with a retrofit situation and will include a retrofit factor in their assessments." (see page 2-28 in EPA/452/B-02-001)

As noted in the above citation, US EPA notes that a retrofit factor can be as high as 1.5, this partially supports the value selected for the Chena BACT cost analysis. The cost model employed during the BACT analysis (i.e., CUECost) suggests the following retrofit factors: 1.0 factor for a new facility, a 1.3 factor for a moderately difficult retrofit, and a 1.6 factor for a difficult retrofit. The user is also given the option to input his own retrofit factor based on plant-specific information. As noted by the Northeast States for Coordinated Air Use Management (NESCAUM) in a in a report entitled "Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for industrial, Commercial, and Institutional (ICI) Boilers an independent researcher (Emmel) noted that:

> "this range (of CUECost retrofit factors) significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs (i.e., electric generating units) less than 100 MW. Emmel also noted that on average, a retrofit factor of 1.45 was more reasonable and that the factor should even be higher when CUECost is applied to ICI boilers."

Two main factors impact selection of the retrofit factor for the Chena plant: space availability and equipment congestion. These two factors will require additional efforts for installation, equipment staging, and maneuverability during construction.

6. Baseline Emissions - Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). The baseline is usually the legal limit that would exist, but for the BACT determination.

Response: The Baseline Emission rate is not a legal limit. As stated in the U.S. EPA 1990 New Source Review Workshop Manual:

> "Calculating Baseline Emissions"
>
> The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. *The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions.* In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. (emphasis added)"

Based on this guidance, the Chena baseline emissions were properly calculated and applied to the BACT analysis.

7. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   Response: The current BACT analyses included operating as is, therefore a factor of safety was not included.

8. Good Combustion Practices - For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices.

   Response: Good combustion practices were not proposed. The operation of existing combustion controls (OFA & LEA) were determined to be BACT for NOx.

9. Interest Rate - All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

   Response: Suggest that the State revise interest rate to prime (currently 5.25%) and equipment life to 10 years, not 15, due to corresponding short remaining lifespan of associated boilers.

10. Economic Analysis for Circulating Dry Scrubber (CDS) - Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

    Response: See attached memo "CDS v SDA Cost Comparison.pdf" for CDS analysis.

11. Review State's Spreadsheets – Review cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010.

    Response: Aurora has provided a review of the ADEC's cost effectiveness spreadsheets and inputs. Comments are included on the spreadsheets. Please reference documents "chena-so2-economic-analyses-adec--With ERM Comments.xlsm" and "chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm".

12. Site-Specific Quotes Needed - The cost analyses, particularly for SO2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Response: Included as attachments within this response are vendor quotes as well as a cost analysis for Dry Sorbent Injection (DSI). Due to time constraints, the consultant was able to provide a +50/-30 cost estimate. Please reference the enclosed documents, to include: "Aurora Energy Preliminary Opinion of Probable Cost.pdf"; "Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf"; "BACT Proposal No. 1899-R1.pdf"; and "Aurora_Chena_DSI_General Arrangement.pdf".

Below are a list of documents that are being provided as enclosures which are referenced within the responses given above. If there are any questions pertaining to the information provided, please contact David Fish at dfish@usibelli.com or 907-457-0230.

Sincerely,

David Fish
Environmental Manager

Enclosures:

1. CDS v SDA Cost Comparison.pdf
2. chena-so2-economic-analyses-adec--With ERM Comments.xlsm
3. chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm
4. Aurora Energy Preliminary Opinion of Probable Cost.pdf
5. Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf
6. BACT Proposal No. 1899-R1.pdf
7. Aurora_Chena_DSI_General Arrangement.pdf
8. Unified Facilities Criteria (UFC) DoD Facilities Pricing Guide (ufc_3_701_01_c1_2018.pdf)
9. ufc_3_701_01_data_tables_may_2018.xlsx
10. NSPS ICI SO2 RE.docx
11. ICI Boilers 20081118 final_revised-Jan2009.pdf
12. EPA Air Pollution Cost Control Manual, sixth edition, January 2002, accessible at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf.

Cc:
Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Denise Koch, ADEC/ Air Quality
Cindy Heil, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/ Air Quality
Buki Wright/ Aurora Energy, LLC
Rob Brown/ Usibelli Coal Mine, Inc.
Tim Hamlin/ EPA Region 10
Dan Brown/ EPA Region 10
Zach Hedgpeth/ EPA Region 10

STANLEYCONSULTANTS, Inc
8000 South Chester Street › Suite 500 › Centennial, CO 80112
303.799.6806 › stanleyconsultants.com

November 1, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Qualitative Cost Comparison of Circulating Dry Scrubber Technology Versus Spray Dryer Absorbers

David:

Per your request Jason Smith and I have developed a comparison between the Circulating Dry Scrubber and Spray Dry Absorption technologies and the expected differences in total installed cost. Jason is an expert in SO_2 scrubbers having participated in the construction, startup, and commissioning of several installations over the course of his career.

The two commercially available semi-dry acid gas scrubbing processes consist of Spray Dryer Absorption (SDA) and Circulating Dry Scrubber (CDS). Both technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with sulfur dioxide (SO2) and sulfur trioxide (SO3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash is 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 process also depend on the humidification of the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduced 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 humidification of the flue gas stream 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 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 pumped, the SDA process can sometimes leverage existing infrastructure such as existing particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system serves to limit 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, just to name a few.

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 typically occurs after a venturi assembly that increases the velocity of the passing gas stream to establish a fluidized bed of alkaline material. The flue gas then passes through this bed and 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 collector be placed at higher elevations. This will ensure that the proper slope is maintained between the collector and the injection point on the absorber tower. It is technically challenging to take an existing 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 to accommodate the higher elevation construct to be handled under a single contract, thus limiting risk for the owner. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the necessary capital outlay for the 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 does not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in a significantly larger installation cost when compared to an equivalent SDA system. Given that the ADEC Preliminary BACT Determination for the Chena Plant (Dated March 22, 2018) has already established that a SDA system is not economically feasible (Table 4-3, Page 12), it can therefore be concluded that the CDS system is economically infeasible as well.

Please let me know if you have any questions or comments regarding the information presented in this letter.

Sincerely,

John P Solan

John P. Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

STANLEYCONSULTANTS, Inc
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303.799.6806 › stanleyconsultants.com

October 30, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Preliminary Opinion of Probable Cost for Addition of Dry Sorbent Injection

David,

This letter serves to document the preliminary results of our opinion of probable cost for the installation of a Dry Sorbent Injection (DSI) System at the Aurora Energy Chena Plant for the control of Sulfur Dioxide (SO_2) emissions.

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 report to the Alaska Department of Environmental Conservation (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 report, ADEC conducted their own analysis and presented their results as a Preliminary BACT Determination in March of 2018. The results developed by ADEC as a part of their analysis were significantly different from the results presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy has hired Stanley Consultants to develop a site-specific, third-party estimate of the costs to install SO_2 emissions control equipment on the four operating boilers at the Chena Combined Heat and Power Plant near downtown Fairbanks. Stanley Consultants will also provide an estimated sorbent consumption rate and a cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, ERM, will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a Dollars/Tons of SO_2 removed basis.

This letter serves to document the preliminary Opinion of Probable Cost results so that Aurora Energy can submit a response to the BACT Determination ahead of a November 1, 2018 deadline. The information included herein relates only to the installation of a DSI system on the existing boilers. All performance information, quantities, and costs are preliminary and are

subject to revision as the cost estimate is refined and finalized. Additional clarifications as to the basis of the cost estimate and the anticipated performance are included below.

Design Basis

Boiler Performance and Flue Gas

Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates from the previous reports were utilized to determine equipment sizes and required sorbent feed rates

Dry Sorbent Unloading, Storage, Preparation, and Injection System

Equipment and piping costs for the Dry Sorbent Injection 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 the emissions from burning Healy coal in stoker-type boilers. The BACT proposal includes:

- 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 is sufficient for four 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.
- 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 equipment or systems that are required for proper operation of the DSI system, but was not included in the BACT proposal have been included separately in the cost estimate. This includes:

- Piping between the sorbent preparation building and the injection lance on each flue
- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse
- Electrical feeds and equipment required to support the BACT equipment
- 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 – Adjacent to the unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment – Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building – Adjacent to the existing baghouse

See the attached sketch for additional information on the proposed equipment locations and interconnecting piping.

Opinion of Probable Cost

Based on the information above, the current estimate of probable cost is as follows:

Total Installed Cost: $20.682MM

Sorbent Cost: $550/Ton, Delivered

Reference the attached spreadsheet for additional information relating to the equipment and construction costs used. Total installed costs include probable costs for engineering, procurement and construction of the DSI system. It also includes mobilization and indirect contractor costs such as bonding, overhead, and profit. Finally, the Total Installed Cost includes an escalation factor to account for inflation and other cost increases over the construction period.

Clarifications

- The estimated accuracy of this Opinion of Probable Costs is +50% and -30%. The accuracy is expected to improve as the cost estimate is refined.
- 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 degrees 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 degrees 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 costs included in this estimate are based on the best information that we have been able to obtain to-date. The refinement of existing costs or the inclusion of additional direct or indirect costs may be determined to be necessary as the preliminary design develops.
- Sorbent pricing information provided by BACT in their equipment proposal was supplied by the sorbent vendor based on a proposal 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 we have available today.

Conclusion

The preliminary Opinion of Probable Cost presented in this letter is our current best estimate for the costs associated with the procurement and installation of a DSI system at the Chena Combined Heat and Power Plant. The estimate attempts to account for many of the site-specific factors that may negatively impact the actual capital costs including, plant configuration, site layout, seismic considerations, existing infrastructure, and local construction cost factors.

We hope the information presented in this letter meets your immediate needs and we look forward to providing you with a final Opinion of Probable Costs along with supporting documentation in the near future.

Thank you for the opportunity to assist Aurora Energy in this matter.

Sincerely,

John Solan
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Attachments: DSI Equipment Layout Sketch

Opinion of Probable Cost Tabulation

Stanley Consultants INC.

		Rev. 0	Job No. 28709.01.00	Page No.	1
			Subject	Aurora Energy Chena - Dry Sorbent Injection	
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 10/29/2018		Opinion of Probable Cost	
Checked by	J. Solan	Date 10/29/2018			
Approved by	C. Spooner	Date 10/30/2018	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	$1,880,200.00	$1,880,200
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	$6,370,000.00	$6,370,000
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	$238.00	$71,400
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$239.00	$74,090
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$239.00	$66,920
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$239.00	$47,800
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	$14,169,111
				Mobilization & Demobilization - 5%	$708,456
				Bond - 2.5%	$354,228
				Contractor Overhead - 10%	$1,416,911
				Contractor Profit - 10%	$1,416,911
				Total Construction Cost	$18,065,617
	Escalation Percent 4.00% Periods 14			Escalation (Nov 2018 - January 2020)	$736,199
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,802,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,682,000**

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.

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 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
Sorbent Prep Enclosure
Unit 5 Injection
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
Google Earth
© 2018 Google
300 ft

UFC 3-701-01
23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

APPROVED FOR PUBLIC RELEASE; DISTRIBUTION UNLIMITED

UFC 3-701-01
23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

Indicate the preparing activity beside the Service responsible for preparing the document.

U.S. ARMY CORPS OF ENGINEERS

NAVAL FACILITIES ENGINEERING COMMAND (Preparing Activity)

AIR FORCE CIVIL ENGINEER CENTER

Record of Changes (changes are indicated by **\1**\ ... /**1**/)

Change No.	**Date**	**Location**
1	6-25-18	Update Table 3 with RUC. Text update 3-2.

This UFC supersedes UFC 3-701-01, dated March 2011.

FOREWORD

The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with USD (AT&L) Memorandum dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of Forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the most stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Center (AFCEC) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: Criteria Change Request. The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site http://dod.wbdg.org/.

Refer to UFC 1-200-01, *DoD Building Code (General Building Requirements)*, for implementation of new issuances on projects.

AUTHORIZED BY:

LARRY D. McCALLISTER, PhD, PE, PMP, SES Chief, Engineering and Construction Directorate of Civil Works U.S. Army Corps of Engineers	JOSEPH E. GOTT, P.E. Chief Engineer Naval Facilities Engineering Command
EDWIN H. OSHIBA, SES, DAF Deputy Director of Civil Engineers DCS/Logistics, Engineering & Force Protection	MICHAEL McANDREW Deputy Assistant Secretary of Defense (Facilities Investment and Management) Office of the Assistant Secretary of Defense (Energy, Installations, and Environment)

UNIFIED FACILITIES CRITERIA (UFC)
[REVISION] SUMMARY SHEET

Document: UFC 3-701-01, *DoD Facilities Pricing Guide*

Superseding: UFC 3-701-01, dated March 2011

Description: The document provides updated cost and pricing data in support of facility planning, investment and analysis needs.

Reasons for Document:

- This UFC provides updated cost and pricing data intended to support preparation of the DoD budget.

Impact:

- Provides consistency across the DoD for the development of budgets for military construction projects.

Unification Issues

None

TABLE OF CONTENTS

CHAPTER 1 INTRODUCTION

1-1 PURPOSE AND SCOPE.

The DoD Facilities Pricing Guide supports a spectrum of facility planning, investment, and analysis needs. This version of the Guide reflects updated cost and pricing data for FY 2018 intended to support preparation of the DoD budget for FY 2020. It includes reference information organized into three chapters, as follows:

1-1.1 Chapter 2: Unit Costs for Military Construction Projects.

Chapter 2 describes the usage of facility unit cost data for selected DoD facility types in support of preparing Military Construction (MILCON) project documentation (DD Forms 1391) and other program-level estimates in accordance with UFC 3-730-01, "Programming Cost Estimates for Military Construction."

1-1.2 Chapter 3: Unit Costs for DoD Facilities Cost Models.

Chapter 3 describes the usage of unit costs in support of DoD facilities cost models. These unit costs are based upon the reported average DoD facility size or an established benchmark size, as annotated for each Facility Analysis Category (FAC) in the DoD Real Property Classification System (published separately). These unit costs are intended for macro-level analysis and planning rather than individual facilities or projects.

1-1.3 Chapter 4: Cost Adjustment Factors.

Chapter 4 describes the usage of cost adjustment factors for location and price escalation that are applicable to the base unit costs in both Chapters 2 and 3.

1-2 APPLICABILITY.

This UFC applies to all projects in both the continental US (CONUS) and outside the continental US (OCONUS).

1-3 DATA TABLES.

All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

1-4 PROPONENT.

The Office of the Assistant Secretary of Defense for Energy, Installations, and Environment is the proponent for the Facilities Pricing Guide. Recommendations from users toward improving the usefulness of this reference are welcome.

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CHAPTER 2 UNIT COSTS FOR MILITARY CONSTRUCTION PROJECTS

2-1 OVERVIEW.

The facility unit costs in this chapter apply to preparation of programming-level cost estimates for constructing military facilities in accordance with the methodology described in UFC 3-730-01.

All data tables in this UFC are found under “Related Materials” in a combined file accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

2-2 FACILITY UNIT COST TABLE.

Table 2 provides facility unit costs for various DoD facility types in dollars per square meter ($/SM) and equivalent English unit cost data in dollars per square foot ($/SF) as of October 2017. The listed facility types represent only those facilities most frequently constructed by the Military Services, and the application of a facility unit cost may not be directly applicable for those facilities with unique requirements. See UFC 3-730-01 for additional guidance on facility unit costs and their application.

The unit costs in Table 2 are average unit costs for new construction based on no less than three project awards per building type occurring since September 2014 for Army, Navy, Air Force, Defense Education Activities (for school projects) and Defense Health Agency (for medical projects) facilities as entered into the Historical Analysis Generator (HII) unit cost database prior to 1 Nov 2017. Facility additions which are less than 25% of the Reference Size of the listed facility type, and projects outside of the continental United States (OCONUS), are included only for Family Housing and DoD Schools. For additional information regarding how the facility unit costs are determined, refer to paragraph 2-3, Guidance Unit Cost Development.

2-3 GUIDANCE UNIT COST (GUC) DEVELOPMENT METHODOLOGY.

2-3.1 Data Source.

The data source for the facility unit costs is all reliable HII project records, after excluding records for reasons stated in paragraph 2-2. In general, all project records for the CONUS and projects from Alaska and Hawaii are included.

Facility level information from all three Services projects is entered into HII database for comparable service category codes (CATCODEs). Normalized project unit costs are statistically analyzed to eliminate outliers before calculating the guidance unit cost (GUC).

2-3.2 Business Rules.

The business rules are reviewed annually prior to updating Table 2 Facility Unit Costs for Military Construction. The business rules include the following components.

- The Tri-Service CATCODEs Cross-walk table groups like service CATCODEs to a common Office of the Secretary of Defense (OSD) Code. OSD Codes are not published and are only utilized for this task of segregating data. A minimum of three projects are required within those defined years to create a dataset. If there is insufficient data available within the above three-year period, the dataset search is extended to the last four years.
- Projects are new construction only.
- Projects are located within the CONUS, plus Hawaii and Alaska, except where noted otherwise in Table 2.
- Projects with extreme variation from the mean (50%) are excluded., and
- Exclusion of inappropriate data for cause.

2-3.3 Data Normalization.

Each facility-specific data set is normalized to the National Average Area Cost Factor (ACF=1) and number of bidders, and escalated to October of the year of interest, before unit costs are averaged.

- Escalation: The DoD Selling Price Index (DoD-SPI), which is an average of three commonly accepted national construction price escalation indices, is utilized to escalate actual project award cost data to October of 2017 for this UFC,
- Number of Bidders: Based on actual bid data for the data set,
- Location: Normalize each project award by the appropriate ACF to the national average of 1.0, and
- Facility Size: Normalize each facility award amount in the dataset for facility size, using a normalization process that looks at the facility size as compared to the average facility size of the selected dataset by OSD code.

2-3.4 Primary Facility Included Costs.

The facility unit costs include the following:

- Minimum antiterrorism design features (reference UFC 4-010-01, “DoD Minimum Antiterrorism Standards for Buildings”) inside the building meeting Table B-1 standoff distance requirements,
- Sales tax on building materials,

- Building information system costs (e.g., conduits, racks, trays, telecommunication rooms) without any specialized communications requirements,
- Installed (built-in) building equipment and furnishings normally funded with MILCON funds,
- Energy Management Control System (EMCS) connections,
- Intrusion Detection System (IDS) infrastructure, including conduits, racks, and trays,
- Sustainable design and construction features - energy consumption reduction requirements mandated before 6 November 2016; and all other sustainable design features for criteria in effect from September 2014 thru September 2017 with the exception of renewable energy generation elements,
- Progressive Collapse premiums for the following specific facility types: Inpatient Hospital/Medical Center, Primary Care Clinic (Attached), Major Command Headquarters Building, Barracks/Dormitory, and Recruit Open Bay (Barracks), and
- Standard foundation systems (e.g. strip/spread footings, thickened edge slab for slab on grade).

2-3.5 Primary Facility Excluded Costs.

The unit costs do not include the following:

- Gross receipt taxes or gross taxes, gross excise taxes, or state commerce taxes,
- “Acts of God” or unusual market conditions,
- Supporting facility costs,
- Equipment acquired with other fund sources, including pre-wired workstations or furnishing systems, intrusion detection systems,
- Sustainable design and construction features - renewable energy generation elements; energy consumption reduction requirements mandated on or after 6 November 2016; and all other features mandated since September 2017; these will be estimated separately in accordance with component guidelines and documented on DD Form 1391 per DoD Instruction 4170.11, Installation Energy Management,
- Special foundations (e.g. pre-stressed concrete piles, caissons), intrusion detection system installation, base exterior architectural preservation guidelines,

- Enhanced Anti-Terrorism (AT) standards (exceeding the minimum in UFC 4-010-01, or when minimum standoff distances [Table B-1] are not achieved) construction contingency allowances,
- Cybersecurity costs,
- Supervision, inspection, and overhead (SIOH),
- Design costs (design-build contracts), and Construction cost growth resulting from user changes, unforeseen site conditions, or contract document errors and omissions.

2-3.6 Primary Facility Cost Considerations.

The following are cost considerations for primary facilities:

- Medical facilities: Unit costs include category A and category B equipment and building infrastructure for category C equipment,
- Housing for Unaccompanied Military Personnel: Unit costs for barracks, dormitories, and Unaccompanied Officers Quarters do not include free-standing kitchen equipment. In addition to using the size adjustment factors, use the project size adjustment factors in UFC 3-730-01,
- Child Development Centers: Unit costs do not include free-standing food service equipment or playground area and equipment,
- Family housing: Unit costs are based upon gross area and include sprinkler systems or fire-rated construction. Unit costs include post-award design costs,
- Reserve facilities other than reserve centers: Use the unit cost of the appropriate facility type, and
- Costs are independent of the acquisition strategy and are not specific to any single construction type.

CHAPTER 3 UNIT COSTS FOR DOD FACILITIES COST MODELS

3-1 OVERVIEW.

This chapter describes the unit costs and related factors used in support of DoD facilities cost models. These unit costs are intended for macro-level analysis and planning and are not reliable for individual facilities or project estimates.

Unit costs and related factors are associated with FACs represented by a 4-digit code in the DoD Real Property Classification System (RPCS), which is a hierarchical scheme of real property types and functions that serves as the framework for identifying, categorizing, and modeling the DoD's inventory of land and facilities. FACs are common across the department and suitable for department-wide applications. For each FAC, Table 3 identifies the associated unit cost to be used in DoD facilities cost models and metrics.

Whenever possible, unit costs and factors have been based upon approved government or commercial benchmarks. Detailed supporting data for unit costs is available, and accompanies this UFC on the WBDG Web site. All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-2 REPLACEMENT UNIT COSTS (RUC).

3-2.1 \1\ Definition and Use of Replacement Unit Costs. /1/

\1\ Replacement unit costs form the basis of calculating Plant Replacement Value (PRV) in a consistent manner across DoD, representing a complete and useable facility built to current DoD design standards. Replacement unit costs can also support large-scale program-level estimates for re-stationing plans with the addition of allowance for site preparation, earthwork, landscaping, and related factors. Replacement unit costs should not be used for individual project estimates. /1/

Replacement \1\ unit /1/ costs include construction of standard foundations, all interior and exterior walls and doors, the roof, utilities out to the 5-foot line, all built-in plumbing and lighting fixtures, security and fire protection systems, electrical distribution, wall and floor coverings, heating and air conditioning systems, and elevators. Replacement \1\ unit /1/ costs do not include project costs such as design, supporting facility costs, special foundations, equipment acquired with other funding sources (e.g. mission-funded components), contingency costs, or supervision, inspection, and overhead (SIOH). \1\ unit /1/ costs also do not include items that are generally considered personal property such as computer systems, and furniture. See paragraph 3-5, Revising Unit Costs, for guidance on requesting changes \1\ to replacement unit costs /1/in Table 3.

3-2.2 \1\ Plant Replacement Value (PRV). /1/

DoDI 4165.14 defines PRV as the cost to design and construct a notional facility to current standards to replace an existing facility on the same site. The factor values are provided in the “Report of the Plant Replacement Value (PRV) Panel, August 2001-May 2003” published by the Office of the Deputy Under Secretary of Defense (Installations and Environment). The standard DoD formula for calculating PRV is:

Equation 3-2 Calculating PRV

PRV = Q x RUC x ACF x HF x PD x SIOH x CF

Where:

PRV is plant replacement value

Q is facility quantity, in the same unit of measure as the RUC

RUC is replacement unit cost found in Table 3 of this UFC

ACF is area cost factor found in Table 4 of this UFC, to account for geographical differences in the costs of labor, materials and equipment

HF is an adjustment of 1.05 to account for increased costs for replacement of historical facilities or for construction in a historic district. The factor is 1.0, should the facility not qualify as “historical”.

PD is a factor to account for the planning and design of a facility; the current value of this factor is 1.09 for all but medical facilities, and 1.13 for medical facilities.

SIOH is the factor to account for the supervision, inspection, and overhead activities associated with the management of a construction project. The current value of the factor is 1.057 for facilities in the (CONUS), and 1.065 (USACE) or 1.062 (NAVFAC) for facilities in the (OCONUS).

CF is a factor of 1.05 to account for construction contingencies

3-3 SUSTAINMENT UNIT COSTS (SUC).

3-3.1 Definition.

Sustainment provides for maintenance and repair activities necessary to keep a typical inventory of facilities in good working order over its expected service life. It includes the following:

- Regularly scheduled adjustments and inspections, including maintenance inspections (e.g., fire sprinkler heads, HVAC systems) and regulatory inspections (e.g., elevators, bridges),
- Preventive maintenance tasks,
- Emergency response and service calls for minor repairs, and
- Major repair or replacement of facility components (usually accomplished by contract) that are expected to occur periodically throughout the facility service life.

Sustainment includes regular roof replacement, refinishing wall surfaces, repairing and replacing electrical, heating, and cooling systems, replacing tile and carpeting and similar types of work as well as overhead costs which include architectural and engineering services. It does not include repairing or replacing non-attached equipment or furniture, or building components that typically last more than 50 years (such as foundations and structural members). Sustainment does not include restoration, modernization, environmental compliance, facility leases, specialized historical preservation, general facility condition inspections and assessments, planning and design (other than shop drawings), or costs related to Acts of God, which are funded elsewhere. Other tasks associated with facilities operations (such as custodial services, grass cutting, landscaping, waste disposal, and the provision of central utilities) are also not included.

3-3.2 Use of Sustainment Unit Costs.

Sustainment unit costs represent the annual average sustainment cost for each FAC, and serve as the basis for calculating annual facilities sustainment requirements for DoD using the following formula:

Equation 3-3 Calculating Sustainment Requirement

$$SR = Q \times SUC \times SACF \times I$$

Where:

SR is sustainment requirement

Q is facility quantity, in the same unit of measure as the SUC

SUC is sustainment unit cost found in Table 3

SACF is sustainment area cost factor found in Table 4

I is the value(s) representing future-year escalation for operation and maintenance accounts, published in Table 4-4.

The Sustainment Requirement for each qualifying asset in the DoD inventory is aggregated by sustaining organization and sustainment fund type in the Facilities Sustainment Model (FSM), published annually.

3-4 UNIT COST SOURCES.

Unit costs for DoD cost models are developed using a variety of sources. These sources fall into the three categories described below, listed in order of preference of use. The source description and source group for each unit cost are identified in Table 3. Supporting documentation for each unit cost calculation is available in the "Supporting documentation" file download accompanying this UFC document on the WBDG website: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-4.1 Source 1 Published Data

Standard, easily-accessible published data that is highly applicable to the FAC. Source 1 is the most desirable due to ease of access, general applicability, and lack of bias. Examples include the DoD Tri-Service Committee on Cost Engineering, Service-specific cost guidance (USACE), commercial cost-estimating guidelines or models, or other Government-published cost guidance from federal, state, or local government agencies (e.g. Fairfax County (Virginia) Park Authority). Non-DoD source 1 data may require refinement for application in DoD, but is still considered source 1 if it closely matches the design attributes of the FAC.

3-4.2 Source 2 Similar Data

Data that is applied to facilities with similar but not identical characteristics (e.g., sewage waste treatment facilities and industrial waste treatment facilities). Source 2 also includes unpublished government or trade association cost data, and Component-validated costs for non-standard facilities that have no commercial counterparts (e.g. missile launch facilities or military ranges).

3-4.3 Source 3 Derived Data

Unpublished project-specific data derived from Component project documents (e.g. DD Forms 1391) or from calculating costs from reported Plant Replacement Value and inventory, or derived from using a ratio of sustainment to construction from a similar source 1 Facilities Analysis Category (e.g. FAC 2115, Aircraft Maintenance Hangar, Depot derived from FAC 2111, Aircraft Maintenance Hangar).

3-5 REVISING UNIT COSTS.

Users of this UFC are encouraged to suggest revisions to the published cost factors, particularly for facilities unique to their mission. Submit proposed changes to the proponent office in accordance with the following guidelines:

- Revised costs should come from an equivalent or superior source,
- Revised costs should be easily audited,
- Revised costs should be consistent with the functional definitions,
- Revised costs should be consistent with the FAC scope and
- Revised costs should be suitable for application throughout DoD.

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CHAPTER 4 COST ADJUSTMENT FACTORS

4-1 LOCATION ADJUSTMENTS.

Table 4-1 provides area cost factors (ACFs) to be used for adjusting “bare” unit costs to location-specific costs for the most common locations.

All data tables in this UFC are found in a combined file under “Related Materials” accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

4-1.1 Application

For military construction projects, use the MILCON ACFs with the primary facility unit costs from Chapter 2 or approved Air Force, Army, or Navy MILCON Pricing Guide. For calculating Plant Replacement Value, use the MILCON ACFs with the appropriate RUCs from Chapter 3. For calculating sustainment costs, use the sustainment ACFs with the appropriate SUCs from Chapter 3.

Do not use the MILCON ACFs to modify parametric cost estimates, detailed quantity-take-offs, unit price book (UPB) line items, commercial cost data, or user-generated unit costs. These cost estimating methods and databases have their own processes and factors for adjusting costs to different locations. MILCON ACFs or any component(s) that make up MILCON ACFs are only applicable to construction costs and should not be applied or utilized for any other purpose.

4-1.2 Data Source

In general, the Tri-Service Cost Engineering ACF software program evaluates the local costs for a United States market basket of eight labor crafts, 18 construction materials, and four equipment items. These labor, materials, and equipment (LME) items are representative of the types of products, services, and methods used to construct most military facilities in the United States. Each of the LME costs is normalized and weighted to represent its contribution to the total cost of a typical facility. The normalized LME is then modified by seven matrix factors that cover local conditions affecting construction costs. These matrix factors include weather, seismic, climatic (frost zone, wind loads, and HVAC systems), labor availability, contractor overhead and profit, logistics, and labor productivity and are relative to the U.S. standard. The resultant ACF for each location is normalized again by dividing by the 96-Base-City average to provide a final ACF that reflects the relative relationship of construction costs between that location and the 96-Base-City average as 1.00.

MILCON ACFs are calculated using a LME ratio of 35/63/2. Sustainment ACFs are calculated using a LME ratio of 53/46/1.

4-1.3 Survey

Both CONUS and OCONUS construction market surveys were conducted in 2017. The CONUS survey covered 300 locations that included 96 Base Cities (two per state in the continental U.S.). The OCONUS survey included 75 locations, and was based on a market basket of goods for typical U.S. labor, material, equipment, and construction methods.

CONUS and OCONUS surveys are performed annually. When local materials and construction methods differ from those represented by the published ACF, specific adjustments may need to be added to the project estimate to account for any differences. There is no easy correlation between the current MILCON ACFs and previous MILCON ACFs for specific locations. No common benchmarks exist because both the Base City average and the relationships between cities change with each survey. It is possible, however, to compare differences between several locations in this database with differences between the same locations in previous databases.

4-1.4 Force Majeure

The ACF is not intended to, or capable of, responding to rapid changes in the market place. Examples include Acts of God, accelerated construction schedules, changes in the demand and supply for construction materials, labor, and equipment. An increased demand for labor beyond what the local market can supply may require the enticement of premium pay, overtime hours, temporary living expenses, and travel expenses.

4-1.5 User Requested Revisions

Users may request revisions to published ACFs when market conditions unexpectedly change. Each request must be initiated by the USACE District senior cost engineer through HQUSACE or by the NAVFAC regional cost engineer to their corresponding NAVFAC Atlantic or Pacific Tri-Service Cost Engineering committee member. The local cost engineer shall provide updated market basket ACF software input factors with adequate backup documentation to HQUSACE or NAVFAC for them to update the Tri-Service Cost Engineering ACF software.

4-2 ESCALATION.

Tables 4-2, 4-3, and 4-4 provide escalation (inflation) factors used to adjust unit costs in Tables 2 and 3 (expressed in base-year dollars) to the desired year, as follows:

4-2.1 Military Construction.

Military construction project estimates that use unit costs from Table 2 should use the military construction escalation factor from table 4-2 for the expected midpoint of construction as described in UFC 3-730-01.

4-2.2 Plant Replacement Value Escalation Rates.

Plant Replacement Value (PRV) calculations that use replacement unit costs from Table 3 should use the escalation factor from Table 4-3 for the desired program year.

4-2.3 Facilities Sustainment.

Modeled facilities sustainment cost estimates that use unit costs from Table 3 should use the O&M escalation factor from Table 4-4 for the desired program year.

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APPENDIX A REFERENCES

UNIFIED FACILITIES CRITERIA

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UFC 3-730-01, *Programming Cost Estimates for Military Construction*

PLANT REPLACEMENT VALUE

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Report of the Plant Replacement Value (PRV) Panel, August 2001 – May 2003, R&K Engineering, Inc. for the Office of the Deputy Under Secretary of Defense (Installations and Environment)

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park NC 27711
EPA-450/3-90-016
August 1990

Air

EPA

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

EPA-450/3-90-016

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1990

2.3.3 Percent Reduction Standard

1. Comment: Two commenters (IV-D-08, IV-D-28) requested that the 90 percent SO_2 reduction requirement be eliminated and replaced with an emission limit of 520 ng/J (1.2 lb/million Btu) heat input. One commenter (IV-D-08) objected to applying the 90 percent SO_2 reduction requirement to all coal regardless of sulfur content. This commenter stated that the EPA's conclusion that no units will be built in the size range between 22 and 29 MW (75 and 100 million Btu/hr) heat input capacity and operating at greater than 55 percent capacity factor is flawed. This commenter stated that the SO_2 standard of 520 ng/J (1.2 lb/million Btu) heat input for coal-fired plants should apply to all steam generating units in this source category, regardless of size. This commenter further recommended that the full 90 percent SO_2 removal be required only when the 520 ng/J (1.2 lb/million Btu) limit could not be met by using low sulfur coals or by pretreating the coals.

Another commenter (IV-D-28) stated that the 90 percent SO_2 reduction requirement should be removed and that coal-fired steam generating units in the 8.7 to 29 MW (30 to 100 million Btu/hr) range should be required only to meet the 520 ng/J (1.2 lb/million Btu) SO_2 limit. The commenter stated that the percent reduction requirement would place an unjustified cost and performance burden on units in this range that either already meet or are close to meeting the 520 ng/J (1.2 lb/million Btu) SO_2 limit.

Response: Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the

Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable. As discussed in the background document, "Model Boiler Cost Analysis for Controlling Sulfur Dioxide (SO_2) Emissions from Small Steam Generating Units" (EPA-450/3-89-14), a small coal-fired steam generating unit of 22 MW (75 million Btu/hr) size and operating at a 55 percent capacity factor has an incremental cost-effectiveness value of about $3,600/Mg ($3,300/ton) relative to an emission limit standard of 520 ng/J (1.2 lb/million Btu). Capital and annualized costs are projected to increase by approximately 20 percent over the regulatory baseline for the percent reductions standard. However, these values increase significantly for units less than 22 MW (75 million Btu/hr) heat input capacity and for any unit less than 29 MW (100 million Btu/hr) operating at an annual capacity factor for coal of less than 55 percent. Imposing these high costs for these units was considered to be unreasonable when compared to the increase in emission reductions achievable by the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less.

Finally, no conclusion was made that coal-fired steam generating units greater than 22 MW (75 million Btu/hr) heat input and greater than 55 percent capacity factor would not be built. Rather, this was a projection of sales over the next five years based on sales trends over the past several years. The sales projections for coal-fired units had no influence on the conclusion of the reasonableness of the percent reduction requirement. (The assumption was used in generating national impacts of the standards.) The model steam generating unit analysis examined the potential impacts of the percent reduction requirement on a coal-fired unit greater than 22 MW (75 million Btu/hr) and greater than 55 percent capacity factor. Therefore, should a unit be built, requiring 90 percent reduction of emissions would be reasonable.

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

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UNITS, SPECIES, ACRONYMS

Acronyms
APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
BOOS – Burners Out of Service
CAA – Clean Air Act
CAAA – Clean Air Act Amendments (of 1990)
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – Electrostatic Precipitators
FBC – Fluidized Bed Combustion
FF – Fabric Filter (also known as baghouse)
FGD – Flue Gas Desulfurization (also known as SO_2 scrubber)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
FSI – Furnace Sorbent Injection
GR – Gas Reburn
HHV – Higher Heating Value
ICI – Industrial, Commercial, and Institutional (boilers)
LAER – Lowest Achievable Emission Rate
LNB – Low-NOx Burner
LSDI – Lime Slurry Duct Injection
LSFO – Limestone Forced Oxidation
LSC – Low-Sulfur Coal (also known as compliance coal)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic-Northeast Visibility Union
MC – Mechanical Collector
NAAQS – National Ambient Air Quality Standard
NCG – Non-Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standards
NSR – Normalized Stoichiometric Ratio
OFA – Overfire Air
PC – Pulverized Coal
PRB – Powder River Basin (coal)
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SCA – Specific Collection Area
SCR – Selective Catalytic Reduction

SD – Spray Dryer
SIP – State Implementation Plan
SNCR – Selective Non-Catalytic Reduction
TCR – Total Capital Requirement
TR – Transformer Rectifier
UBC – Unburned Carbon
US EIA – United States Energy Information Administration
US EPA – United States Environmental Protection Agency
ULNB – Ultra Low-NOx Burner
VOM – Variable Operating and Maintenance (costs)
WESP – Wet Electrostatic Precipitator
WFGD – Wet Flue Gas Desulfurization (also known as wet SO_2 scrubber)

Chemical Species
HCl – Hydrochloric Acid
HF – Hydrofluoric Acid
H_2SO_4 – Sulfuric Acid
NOx – Oxides of Nitrogen (NO_2 and NO)
NO – Nitric Oxide
NO_2 – Nitrogen Dioxide
NH_3 – Ammonia
$PM_{2.5}$ – Particulate Matter up to 2.5 μm diameter in size
PM_{10} – Particulate Matter up to 10 μm diameter in size
S – Sulfur
SO_2 – Sulfur Dioxide
SO_4 – Sulfate
VOC – Volatile Organic Compound

Units
Length
m – meter
μm – micrometer or micron (0.000001 m; 10^{-6} m)
km – kilometer (1000 m; 10^3 m)
Mm – Megameter (1,000,000 m; 10^6 m)

Flow Rate
acfm – actual cubic feet per minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 g; 10^{-6} g)

kg – kilograms (1000 g; 10^3 g)

Force
psi – pounds per square inch

Power
W – watt (Joules/sec)
kW – kilowatt (1000 W; 10^3 W)
MW – megawatt (1,000,000 W; 10^6 W)

Energy
Btu – British thermal unit (= 1055 Joules)
MMBtu – million Btu
MWhr – megawatt-hour
kWhr – kilowatt-hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

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Andrew Bodnarik, New Hampshire Department of Environmental Services

Sunila Agrawal, New Jersey Department of Environmental Protection

NESCAUM is an association of the eight northeast state air pollution control programs and provides technical guidance and policy advice to its member states.

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EXECUTIVE SUMMARY

ES-1 Objectives

The main objective of this study is to evaluate the viability of technologies for controlling emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) from industrial, commercial, and institutional (ICI) boilers. These pollutants contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. This source sector is coming under increased scrutiny by air quality regulators needing emission reductions to meet Clean Air Act requirements.

This study also includes a literature review of emission control costs and develops methods for estimating the costs and cost effectiveness of air pollution controls for ICI boilers. The study concludes that ICI boilers are a significant source of emissions, are relatively uncontrolled compared to electricity-generating units (EGUs), and offer the potential to achieve cost effective reductions for all three pollutants. The results of this technical and economic evaluation are intended as a resource in assessing regulatory and compliance strategies for ICI boilers.

Most of the technologies considered in this report have been successfully applied to the larger EGU boilers. This study investigates both the feasibility of down-scaling such control technologies for ICI boiler applications and of certain technologies that have not been applied to EGUs, but show promise for the ICI boilers.

ES-2 Report Organization

Chapter One provides an overview of the ICI boiler fleet in terms of boiler size, applications, fuel type and associated emissions. Chapters Two, Three, and Four discuss control technology options for NOx, SO_2 and PM, respectively. Each chapter provides: (1) descriptions of available control technologies; (2) a discussion of the applicability of these technologies to ICI boilers; (3) published cost estimates; and (4) an assessment of the impact of control technologies on overall facility efficiency. Chapter Five summarizes information about air pollution control equipment costs for ICI boilers calculated with the Coal Utility Environmental Cost (CUECost) model.

ES-3 Differences between ICI and EGU Boilers

ICI and EGU boilers differ in size, application, design, and emissions. Most commercial and institutional boilers are relatively small, with an average capacity of 17 MMBtu/hour. Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. By contrast, the average size of a coal-fired EGU boiler in the U.S. is greater than 2,000 MMBtu/hr.

All coal-fired EGUs in the United States are equipped with PM control devices and many have SO_2 and NOx emission controls. ICI boilers are significantly less likely to have air pollution control devices.

As part of this study, NESCAUM conducted a preliminary survey of the use of emission controls on ICI boilers in the Northeast. Survey results revealed that more than half of the units surveyed in the region had no controls; about one-third had PM controls, while very few units

had NOx controls. None of the surveyed units had SO_2 controls, although some have wet venturi scrubbers for PM control, which minimally reduce SO_2 emissions.

Technical, operational, economic and regulatory factors impose different opportunities and constraints on the applicability of air pollution control devices (APCDs) for EGU and ICI boilers. The following technical and operational characteristics must be evaluated in determining the potential applicability of emission controls for specific ICI boilers.

- Fuel type and quality – SO_2, PM, and NOx emissions from coal-fired boilers are typically higher than from those burning natural gas, oil, or wood waste. Some APCD technologies are not particularly sensitive to such variations. For example, an electrostatic precipitator (ESP) or a fabric filter (FF) can accommodate different PM concentrations, although the type and size of PM and gas temperatures will have an impact. Other controls that utilize reagents, such as SO_2 scrubbers and selective catalytic reduction or selective non-catalytic reduction (SCR/SNCR) technologies for NOx, are directly affected by fuel type and quality.
- Duty cycle – APCD controls must be capable of accommodating significant variation or cycling of boiler loads. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – The presence of equipment such as economizers or air preheaters has a direct impact on flue gas temperatures. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers, and SCR/SNCR that are widely used in EGUs may or may not be applicable to ICI boilers in certain cases.

ES-4 NOx Control Technologies

Emission control strategies for NOx can be divided into two basic categories: combustion modifications and post-combustion technologies. Control efficiency ranges and cost effectiveness ($/ton of NOx removed) for various technologies are provided in Table ES-1. Combustion modification technologies, which minimize the formation of NOx during the combustion process, include: combustion tuning; low-NOx burners and overfire air (LNBs and OFA); and gas, oil, or coal reburn.

LNBs have minimal effect on overall operating costs, but may introduce higher carbon monoxide and/or carbon levels in the fly ash, which reflect lower plant efficiency. In the case of gas reburn, operating costs are primarily a function of the fuel cost differential; for coal or oil reburn, fuel preparation costs (pulverization and atomization, respectively) represent the primary operating and maintenance costs. While gas reburn is easier to implement, the fuel differential costs are often prohibitive. The overall cost of low-NOx combustion technology installation depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity.

Post-combustion technologies reduce the amount of NOx exiting the stack that was formed during combustion. This group includes SNCR, SCR, and regenerative SCR (RSCR) technologies. Because the reaction occurs without the need for catalysts, SNCR systems have

lower capital costs, but achieve lower NOx reduction. SCR, on the other hand, is capital-intensive, but offers the opportunity for significantly greater NOx reductions because a dedicated reactor and a reaction-promoting catalyst ensure a highly controlled, efficient reaction. RSCR combines a regenerative thermal oxidizer with SCR technology, making it suitable for facilities with lower gas temperatures, such as those found in some ICI boilers. RSCRs can also reduce carbon monoxide emissions by half.

ES-5 SO_2 Control Technologies

SO_2 emission control technologies are post-combustion devices that utilize a process involving SO_2 reacting in the exhaust gas with a reagent (usually calcium- or sodium-based) and removal of the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 control technologies are commonly referred to as flue gas desulfurization (FGD) and/or "scrubbers" and are usually characterized in terms of the process conditions (wet vs. dry), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable). Wet scrubbers provide much greater levels of SO_2 control. Conventional dry processes include spray dryers (SDs) and dry sorbent injection (DSI). The capital costs of wet scrubbers are higher than those of dry scrubbers, although the cost effectiveness values (in dollars per ton of SO_2 removed) of wet and dry processes are similar. DSI technology has a significantly lower capital cost than wet or dry scrubbers and should therefore be more attractive for ICI boilers than conventional scrubbers.

In the eight-state NESCAUM region, residual oil is a common fuel for ICI boilers. Switching to a lower sulfur residual oil (for example, from 3 percent to 1 percent sulfur residual oil) can provide cost-effective SO_2 reductions. The cost of switching to lower sulfur distillate oil is much higher than switching to low sulfur residual oil, because the cost of distillate oil has been about twice that of residual oil in recent years. The cost effectiveness (in dollars per ton of SO_2 removed) from switching from residual fuel oil to distillate fuel oil is not as attractive and falls in the range of the cost effectiveness of installing a FGD scrubber.

ES-6 PM Control Technologies

Combustion processes emit both primary and secondary particulate matter. Primary emissions consist mostly of fly ash (e.g., non-combustible inorganic matter and unburned solid carbon). Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter. PM control technologies include: fabric filters or "baghouses," wet and dry ESPs, venturi scrubbers, cyclones, and core separators. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired ICI boilers.

ES-7 Impact of Control Technologies on Operational Efficiency and Carbon Dioxide Emissions

Air pollution control technologies and strategies (e.g., fuel switching) can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative depending on technology and fuel choices.

Carbon dioxide (CO_2) emissions are primarily a function of the carbon content of fuels. However, the application of conventional pollutant control technologies can affect CO_2 emissions. This impact can vary widely among technologies within the same pollutant (e.g.,

LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. scrubbers for SO_2).

Combustion modification technologies for NOx have essentially no impact on the CO_2 emissions of the host boilers – with the noted exception of reburn when displacing coal or oil with natural gas – because the technologies do not impose any significant parasitic energy consumption (auxiliary power) requirements. With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy demand on the host boiler. These impacts include pressure, compressor, vaporization, and steam losses, and can range from 1–2 kW/1000 actual cubic feet per minute (acfm) for SNCR and up to about 4 kW/1000 acfm for SCR.

The major components affecting energy consumption for SO_2 systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. The power consumption of the SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. SO_2 controls have a range of potential parasitic losses, from duct injection representing about 1–2 kW/1000 acfm to wet FGD at as high as 8 kW/1000 acfm.

PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can be up to 10 kW/1000 acfm or higher.

ES-8 Cost Analysis

Cost is an important factor in evaluating the viability of air pollution control technologies. Information on capital and operating costs is more readily available for EGU than ICI boilers. Operating costs may be different for ICI boilers than utility boilers because of their size and the fact that they are typically located on smaller sites. Operating costs also include waste disposal and reagent use. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs, as a percentage of total capital cost, than those for utility boilers.

Cost estimates for ICI boilers with capacities ranging from 100 to 250 MMBtu/hr were generated by the CUECost model. This model, created by Raytheon Engineers for US EPA, was originally developed for large coal-fired EGUs and calculates capital and operating costs for certain pre-defined air pollution control devices for NOx, SO_2, and PM. The CUECost model produces approximate estimates (±30 percent accuracy) of installed capital and annualized operating costs. The CUECost model was adapted in this study for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. This study represents the first attempt to utilize a comprehensive cost model specific to ICI boilers.

Chapter Two contains a detailed discussion of the literature values for NOx control costs for ICI boilers. The NOx control costs for ICI boilers computed with CUECost were largely consistent with values reported in the literature. In terms of NOx removal, reported values were in the range of \$1,000 to \$3,000 per ton for LNBs or SNCR, and \$2,000 to \$14,000 per ton for SCR. The SCR costs for coal-fired ICI boilers appear to be consistent with the literature, although the CUECost capital cost values for residual oil were higher than the literature values. The capital costs for SNCR calculated from the CUECost models were in good agreement with literature values, particularly their sensitivity to boiler capacity. The capital costs for LNBs

calculated from CUECost for coal-fired boilers were consistent with the literature values, although the costs for residual oil-fired boilers were higher in CUECost than the literature values.

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs for ICI boilers. In terms of the cost per ton of SO_2 removed, reported values were in the range of $1,600 to $5,000 for spray dryers (SDs) and $1,900 to $5,200, for wet FGDs. The SO_2 capital costs computed with CUECost for SDs were in the range of the literature values at 250 MMBtu/hr. However, the capital costs computed by CUECost for wet FGDs were high compared to values reported in the literature.

Chapter Four contains a detailed discussion of the literature values for PM control costs. Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to industrial boilers. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM for coal and up to $15,000 per ton of PM for oil.

The dry-ESP control costs computed with CUECost were consistent with the literature values, although the CUECost predicted slightly higher values than reported by EPA for dry, wire-plate ESPs. The baghouse/fabric filter costs computed with CUECost were higher than the literature values for pulse-jet fabric filters.

This adaptation of CUECost model from EGUs to ICI boilers was intended to investigate the feasibility of estimating costs of controlling emissions of NOx, SO_2, and PM from ICI boilers. Further detailed work would be needed to validate this approach, but initial results included in this report are promising.

ES-9 Conclusion

ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. These boilers are relatively uncontrolled compared to EGUs and offer the potential to achieve cost-effective reductions for all three pollutants. A host of proven emission control technologies for EGUs can be scaled-down and deployed in industrial, commercial, and institutional settings to cost-effectively reduce emissions of concern. Other technologies that have not been applied to EGUs show promise for ICI boiler applications. Careful analysis will be needed to match the appropriate emission control technology for specific applications given: boiler size, fuel type/quality, duty-cycle, and design characteristics. Further, regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls.

Table ES-1. ICI Boiler Control Technologies

Pollutant	Technology	Control Efficiency	Cost Effectiveness $ per ton
NOx			
Combustion Modifications	Tuning	5-15%	current data not available
	LNB	25-55%	$750-$7,500
	Reburn	35-60%	current data not available
Post-Combustion	SNCR	30-70%	$1,300-$3,700
	SCR	70-90%	$2,200-$14,400
	RSCR	60-75%	$4,500
SO_2	Wet Scrubbers	95+%	$1,900-$5,200
	Spray Dryers	90-95%	$1,600-$5,200
	Dry Sorbent Injection	40-90%	current data not available
PM			
	Fabric Filters/Baghouses	99+%	$400-$1,000 – coal $6,900-$16,500- oil
	Wet/Dry ESPs	99+%	$160-$2,600 – coal $2,300 to $43,000 - oil
	Venturi Scrubbers	50-90%	current data not available
	Cyclones	70-90%	current data not available
	Core Separators	60-75%	current data not available

1 INTRODUCTION

1.1 Objectives

The main objective of this study is to evaluate various available control technologies and their cost effectiveness in reducing emissions of three pollutants: oxides of nitrogen (NOx), sulfur dioxide (SO_2), and primary fine particulate matter ($PM_{2.5}$) from industrial, commercial, and institutional (ICI) boilers. The study results should provide a strong technical and economic basis for developing cost-effective regulations and strategies to reduce emissions of these three major pollutants from ICI boilers.

1.2 Regulatory Drivers

Federal, state and local governments regulate all major criteria air pollutants under the authority of the Clean Air Act (CAA). The CAA mandates control of pollutants such as NOx, SO_2, and $PM_{2.5}$ to attain and maintain National Ambient Air Quality Standards (NAAQSs) for ozone and $PM_{2.5}$, reduce acidic deposition, and improve visibility under regional haze regulations. Emission standards for specific source categories, including ICI boilers, are also set by federal, state, and local governments to attain and maintain a NAAQS. Examples of these emission standards include New Source Performance Standards (NSPS), Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Reasonably Available Control Technology (RACT), and Best Available Retrofit Technology (BART).

States must formulate State Implementation Plans (SIPs) that provide a framework for limiting air emissions from major sources as part of a strategy for demonstrating attainment and maintenance of NAAQS. Some individual SIPs (if allowed by the state law) may set more stringent limits on emissions of NOx, SO_2, and $PM_{2.5}$ than required by the federal rules. However, states cannot set less stringent limits than required by federal rules and regulations. Generally, federal, state, and local permitting authorities rely upon available information on the latest advanced technologies for emission control when setting emission limits. Where applicable, permitting authorities require BACT and RACT in order to reduce air emissions from stationary sources. In areas that have not achieved a NAAQS (i.e., non-attainment areas), the CAA requires air pollution limits established by LAER for new major stationary sources and major modifications to existing stationary sources. BACT and RACT analyses consider the cost of controls. LAER control technologies, applicable to new major sources located in non-attainment areas, must be installed, operated and maintained without consideration of costs.

1.3 Characterization of Combustion Sources

1.3.1 Description of Combustion Sources

Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines.

Boiler size is typically represented in four ways: fuel input in units of MMBtu/hr, output of steam in lb steam/hr at a specified temperature and pressure, boiler horsepower (1 boiler hp = 33,475 MMBtu/hr), or electrical output in MWhr or MW (if electricity is generated).

The three main types of boilers are described below:

- *Firetube boilers*. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 MMBtu/hr.
- *Watertube boilers*. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a “wall.” Watertube boilers vary in size from less than 10 MMBtu/hr to10,000 MMBtu/hr.
- *Fuel-firing*. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal (PC) enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to “suspend” the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

Boilers are also classified by the fuel they use – chiefly coal, oil, natural gas, wood, and waste byproducts.

1.3.2 Emissions by Size, Fuel, and Industry Sector

In 2005, Energy & Environmental Analysis, Inc. [EEA, 2005] estimated that there were 162,805 industrial and commercial boilers in the U.S., which had a total fuel input capacity of 2.7 million MMBtu/hr as summarized in Figure 1-1 and Table 1-1. This estimate included 43,015 industrial boilers with a total capacity of 1.6 million MMBtu/hr and 119,790 commercial boilers with a total capacity of 1.1 million MMBtu/hr. In addition, EEA estimated that there were approximately 16,000 industrial boilers in the non-manufacturing sector with a total capacity of 260,000 MMBtu/hr, but details on size distribution of these boilers were not provided because these units were not well characterized.

The EEA report divided boilers into two major categories (industrial and commercial) instead of the more common characterization as industrial, commercial, and institutional boilers. One segment of the ICI boiler population, identified as non-manufacturing industrial boilers, is not included in the EEA analyses due to a lack of sufficient data. The non-manufacturing segment accounted for only 11 percent of energy consumption in the industrial boiler population. The manufacturing and non-manufacturing segment of the population appear (from EEA’s description) to correspond to what would be called industrial boilers. The commercial segment of the population includes what are designated in this report as commercial and institutional boilers. For example, there are several large boilers located at major institutions such as universities (e.g., Notre Dame, Cornell, etc.) and also several large boilers located at major hospitals (e.g., Massachusetts General Hospital) that belong in the institutional category instead

of the commercial sector. Thus, EEA's analysis appears to apply to most of the ICI boiler population, representing 89 percent of energy use by ICI boilers.

Industrial boilers were generally larger than commercial units. Sixty percent of the boilers in the manufacturing sector were greater than 100 MMBtu/hr in capacity, whereas 60 percent of the boilers in the commercial sector were in the range of 10 to 100 MMBtu/hr. The average capacity of the commercial boilers was 10 MMBtu/hr, with most less than 10 MMBtu/hr; the capacity of the average industrial boiler was 36 MMBtu/hr. Non-manufacturing boilers fell in between, at an average capacity of 16 MMBtu/hr. For industrial boilers, the average capacity factor was 47 percent (capacity factor is defined as the ratio of actual heat input in MMBtu to the maximum heat input based on nameplate capacity of the unit, calculated for a period of one year).

Table 1-1. Capacity of industrial boilers [EEA, 2005]

Unit Capacity	Manufacturing Boilers	Non-Mfg Boilers*	Commercial Boilers	Total
<10 MMBtu/hr	102,306	---	301,202	403,508
10-50 MMBtu/hr	277,810	---	463,685	741,495
50-100 MMBtu/hr	243,128	---	208,980	452,108
100-250 MMBtu/hr	327,327	---	140,110	467,437
>250 MMBtu/hr	616,209	---	33,639	649,848
Total Capacity, MMBtu/hr	1,566,780	260,000	1,147,617	2,714,397
Total Capacity >10 MMBtu/hr	1,464,474	---	846,415	2,310,889**
Total number of units	43,015	16,000	119,790	162,805
Average Capacity, MMBtu/hr	36	16	10	17

*No details provided on range of capacities
**Total does not include non-manufacturing boilers

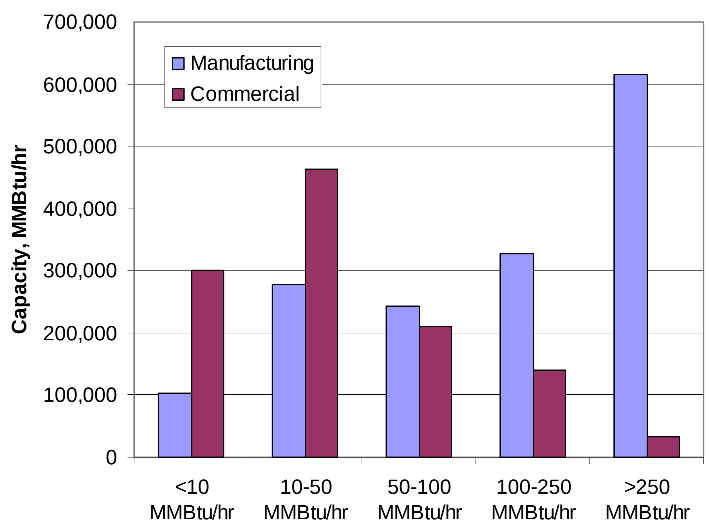


Figure 1-1. Total capacity of industrial boilers as a function of size [EEA, 2005]

Five major steam-intensive industries accounted for more than 70 percent of the boiler units and more than 80 percent of the boiler capacity of the manufacturing segment of industrial boilers: food, paper, chemicals, petroleum refining, and primary metals. The non-manufacturing segment of the industrial sector included agriculture, mining and construction. The largest categories in the commercial sector, by capacity, were schools, hospitals, lodgings, and office buildings.

Industrial boilers in the manufacturing sector are used to generate process steam and electricity. The fuels used in manufacturing boilers are related to the size of the boilers and, in some cases, the byproducts generated in the particular manufacturing process.

In the food production subsector, the average boiler capacity was 20 MMBtu/hr. The relatively small average capacity was reflected in the higher percentage (58 percent) of natural gas-fired boilers in the food industry than in any other major subsector, since very small boilers tend to burn natural gas.

The paper industry included some of the largest industrial boilers, with an average boiler size of 109 MMBtu/hr. The paper industry represented more than half (230,000 MMBtu/hr) of the total capacity of the manufacturing sector. More than 60 percent of the fuel used in paper industry boilers was wood (bark, wood chips, etc.) or black liquor, a waste product from the chemical pulping process.

The chemical industry employed both large and small boilers, with about seven percent of the units with capacities smaller than 10 MMBtu/hr, and a significant number (about 350 or 37 percent of total capacity) larger than 250 MMBtu/hr. The primary fuels for chemical industry boilers were natural gas (43 percent), process off-gas (39 percent), and coke (15 percent).

The refining industry had an average boiler size of 143 MMBtu/hr, the largest of any of the major industries, with over 200 boilers with capacities above 250 MMBtu/hr. By-product fuels (refinery gas or carbon monoxide) were the most common fuel source for boilers (58 percent), followed by natural gas (29 percent) and residual oil (11 percent).

About half of the total boiler capacity in the primary metals industry was from boilers larger than 100 MMBtu/hr. By-product fuels, like coke oven gas and blast furnace gas, provided the largest share (63 percent) of boiler fuel in the primary metals industry.

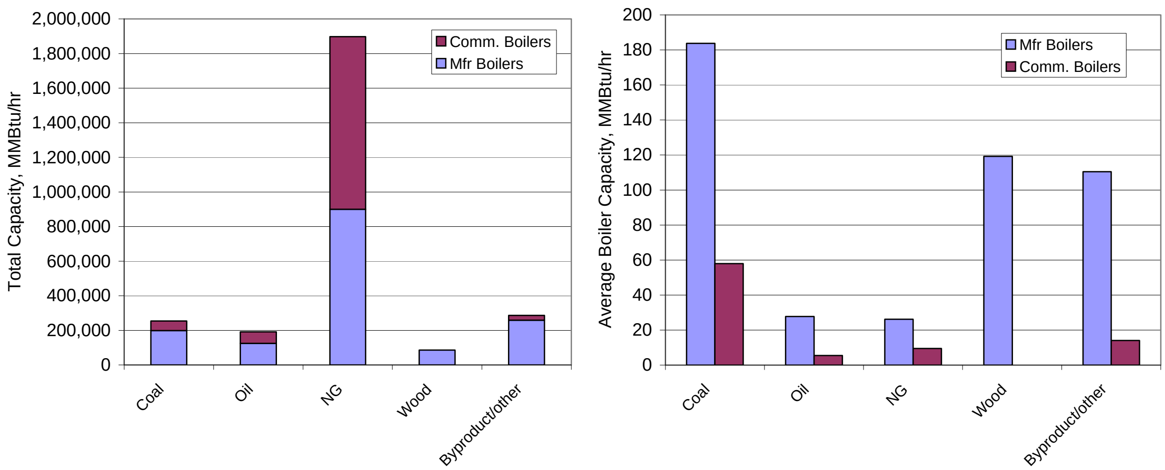
The remaining industries accounted for about 29 percent of manufacturing boilers (12,000 units) or about 18 percent of industrial boiler capacity. The average capacity for the rest of the manufacturing subsector was 23 MMBtu/hr. Approximately 100 boilers at other manufacturing facilities had capacities larger than 250 MMBtu/hr.

Unlike industrial boilers, which serve production processes, commercial boilers provide space heating and hot water for buildings. Natural gas fired the vast majority of commercial boilers, including 85 percent of commercial boiler units and 87 percent of the total commercial boiler capacity. About 10 percent of the commercial boilers were fired by oil. Coal was fired at about one percent of the commercial boilers, but represented five percent of the capacity, reflecting the larger size of commercial coal-fired boilers.

Figure 1-2 summarizes the total US boiler capacity in the manufacturing and commercial sectors as a function of fuel fired (left side of figure) and shows the average capacity per boiler (right side of figure) by fuel type. Coal-fired boilers were the largest in size on average. As discussed above, natural gas accounted for 70 percent of the total industrial boiler capacity in the

EEA survey. Coal and byproduct fuels accounted for about 10 percent each, with lesser capacity in oil- and wood-fired boilers.

In the manufacturing sector, the average coal-fired boiler capacity was about 180 MMBtu/hr, but the average capacity in both sectors combined was about 125 MMBtu/hr. Wood- and byproduct-fired boilers in the manufacturing sector were also large on average (120 and 110 MMBtu/hr, respectively). On the other hand, oil- and natural gas-fired boilers were small, on the order of 20 MMBtu/hr in the manufacturing sector and less than 10 MMBtu/hr in the commercial sector.



(a) Total capacity by fuel and sector (b) Average capacity by fuel and sector

Figure 1-2. Total and average boiler capacity of U.S. industrial boilers as a function of fuel fired [EAA, 2005]

From EEA's 2005 study, the following general conclusions about boiler size for the entire U.S. ICI boiler population can be drawn:

- natural gas is the fuel fired at most ICI boilers;
- natural gas- and oil-fired boilers tend to be small, less than 20 MMBtu/hr in capacity;
- boilers fired with coal, wood, or process byproducts are larger in size, greater than 100 MMBtu/hr on average;
- although natural gas fired most of the ICI boilers in the U.S., coal, oil, and wood contribute substantially more to the emissions of SO_2 and PM; and
- all fuels are sources of NOx emissions.

One needs to be careful drawing conclusions for the eight-state NESCAUM region based on the national data in the EEA 2005 study because there are large region-to-region and state-to-state differences in boiler populations. For example, fuel oil is an important fuel in the Northeast, especially in rural areas where natural gas may not be available, while natural gas is predominant in other areas of the country.

A preliminary assessment of emissions from ICI boilers by pollutant in the U.S. and in the eight-state NESCAUM region was carried out using data from the AirData database via the EPA website (www.epa.gov/air/data). In this database, stationary sources, such as electric generating plants and factories, are identified individually by name and location. Figure 1-3 compares the annual emission of NOx, SO_2, and $PM_{2.5}$ in the U.S. with the eight-state NESCAUM region for 2002. Emissions in the NESCAUM region are about 5 percent of the US total emissions.

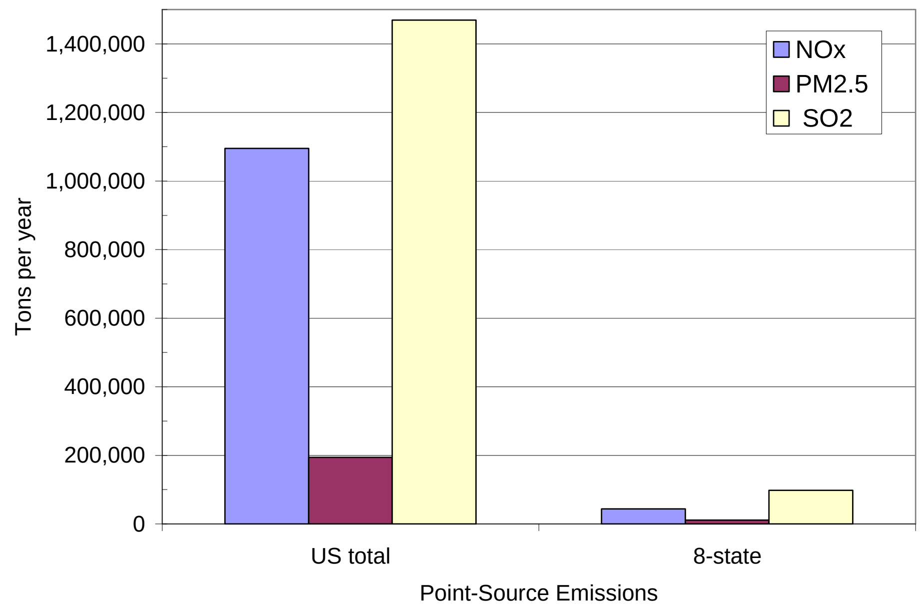


Figure 1-3 Total annual emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the U.S. and in the eight-state region from EPA AirData database

Another set of data from the eight-state region was extracted from the MANEVU 2002 non-road inventory (www.manevu.org). In this data set, oil-fired boilers were divided into distillate oil and residual oil-fired boilers (Figure 1-4).

NOx emissions in the eight-state NESCAUM region are mostly from oil- and gas-fired boilers. Because these are generally small boilers, combustion controls are good candidates for NOx control. For larger, coal- or wood-fired boilers, SNCR or SCR might also be applicable.

PM emissions are relatively low from coal-fired sources in the eight-state region, which suggests that most of the coal-fired sources already have particulate control devices. Oil- and wood-fired units have higher PM emissions, and PM emissions attributed to natural gas are quite small.

As might be expected, most of the SO_2 emissions from oil-fired boilers come from residual oil-fired boilers because of residual oil's higher sulfur content.

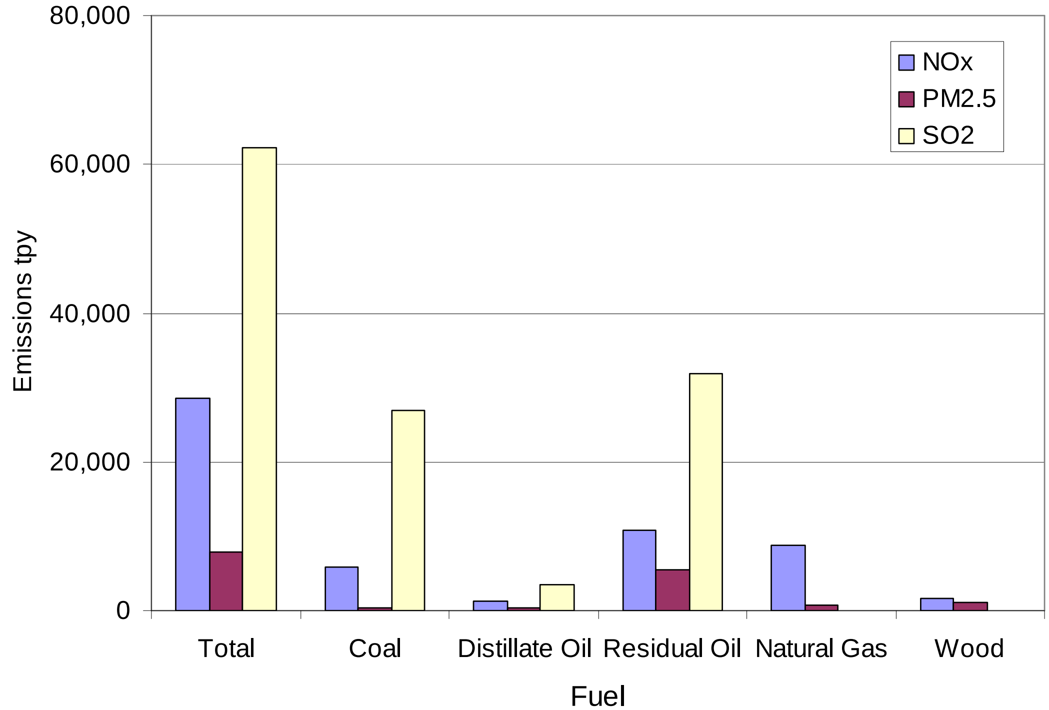


Figure 1-4. Emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the NESCAUM region from MANEVU database as a function of fuel fired

1.3.3 Differences between EGU and ICI boilers

EGU boilers produce steam in order to generate power. While ICI boilers do in some cases generate steam for electricity production, ICI boilers differ from EGUs in size, steam application, design, and emissions. Most commercial and institutional boilers are small, with an average capacity of 17 MMBtu/hour (Table 1-1). Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. The average size of a coal-fired EGU boiler in the U.S. is over 200 MW or over 2,000 MMBtu/hr.

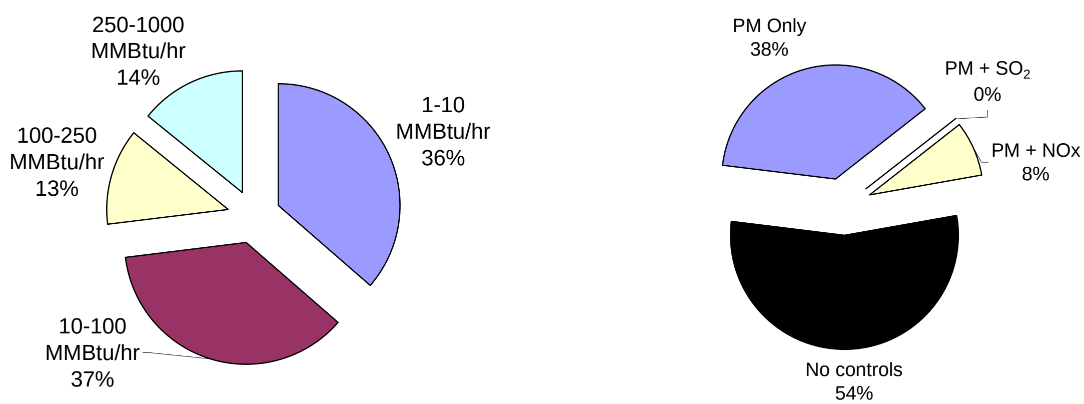
All coal-fired EGUs in the United States use control devices to reduce PM emissions. Additionally, many of the EGU boilers are required to use controls for SO_2 and NOx emissions, depending on site-specific factors such as the properties of the fuel burned, when the power plant was built, and the area where the power plant is located.

According to 1999 EPA Information Collection Request (ICR) responses from coal-fired EGUs, 77.4 percent of EGUs had PM post-combustion control only, 18.6 percent had both PM and SO_2 controls, 2.5 percent had PM and NOx controls, and 1.3 percent had all three post-combustion control devices [Kilgroe *et al.*, 2001]. Information from 2004 indicated that the fractions of total capacity of large coal-fired EGUs that have flue gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NOx controls were 38 percent and 37 percent, respectively [NESCAUM, 2005]. Since the 1999 ICR survey, additional NOx and SO_2 controls have been added at a rapid pace to coal-fired EGUs. It is presently not clear how

the implementation of NOx and SO_2 control technologies for EGUs would evolve as a consequence of the recent vacatur of Clean Air Interstate Rule (CAIR) by the U.S. D.C. Circuit.

In contrast to EGUs, ICI boilers are substantially less likely to have air pollution control devices. A study of industrial boilers and process heaters [USEPA, 2004] that looked at 22,117 industrial boilers and process heaters, which burned natural gas, distillate oil, residual oil, and coal, found that 88 percent had no air pollution control equipment.

A preliminary survey was undertaken as part of this study to evaluate the extent to which various emission controls were currently being applied to ICI boilers in the Northeast. These data were acquired from State Title V permits for solid-fueled (coal and wood) boilers as well as additional information from state personnel. The survey collected data in four states: Massachusetts, Vermont, New Hampshire, and New York. The data set was composed of 64 boilers – 47 wood-fired and 17 coal-fired. *Figure 1-5* illustrates the distribution of boiler capacity (by size) and the air pollution control devices (APCDs) in this data set. The full data set is summarized in Appendix A. As can be seen in *Figure 1-5(b)*, more than half of the units had no controls, about one-third had controls only for PM, and very few units had controls for NOx. There were no units with SO_2 controls, although some of the PM controls were wet venturi scrubbers, which might have a limited impact on SO_2 emissions.



(a) Distribution of capacity (b) Distribution of APCDs

Figure 1-5. Solid-fuel boiler information from four northeast states, based on Title V permit information

There are several factors that directly or indirectly affect the reasons for the discrepancy in APCD deployment between EGU and ICI boilers. Technical and operational as well as business, economic, and regulatory factors impose different constraints and provide different opportunities for the applicability of APCDs for these two categories of boilers. The following discussion summarizes some of the important technical and operational issues.

Large, base-loaded EGUs operate mainly near maximum capacity or steam production. Industrial boilers typically do not run at maximum capacity, although this varies from one industry to another [EEA, 2005]. EGUs produce steam for electricity generation, while ICIs may produce steam for a variety of applications. The type of manufacturing is often more important

in determining boiler operation, or duty cycle (load vs. time) than manufacturing demand in general.

ICI boilers generate steam for processing operations for paper, chemical, refinery, and primary metals industries. Commercial boilers produce steam for a variety of processes, while institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities.

Another difference between EGU and ICI boilers is fuel diversity. EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), while ICI boilers tend to be designed for and use a more diverse mix of fuels (e.g., fuel by-products, waste, wood) in addition to the three conventional fuels above.

These differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of APCD applicability. Examples that directly affect APCD choice and applicability include equipment such as economizers or air preheaters, which affect the temperature of the flue gas at the stack. The differentiation in fuel usage also leads to different design parameters for emissions controls. For example, the iron and steel industry generates blast furnace gas or coke-oven gas, which is used in boilers, resulting in sulfur emissions. Pulp and paper boilers may use wood waste as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category.

These factors relate directly to APCD equipment choices and applicability. The following examples should help explain some of these impacts.

- Fuel quality – different fuels have different emission characteristics. SO_2, PM, and NOx emissions from coal fired boilers are different from those burning natural gas, oil, or wood waste. Some APCD technologies are not very sensitive to fuel quality variations (e.g., an electrostatic precipitator (ESP) may accommodate different levels of PM concentration, although the type and size of particles and gas temperatures will have an impact). However, others can be directly affected by changes in fuel quality and the resulting changes in pollutant concentrations in the flue gas to be treated (e.g., SO_2 and NOx controls that utilize reagents such as scrubbers for SO_2 and SCR/SNCR for NOx).
- Duty cycle – significant variation or cycling of boiler load requires APCD controls capable of accommodating such variations. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – the use of equipment such as economizers or air preheaters has direct impact on the resulting flue gas temperature. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers (wet and dry), and SCR /SNCR that are widely used in EGUs may or may not be applicable for some ICI boilers in such cases.

1.3.4 Control Technology Overview

A variety of emission control technologies are employed to reduce emissions of NOx, SO_2, and primary PM emissions. Technical details of control technologies for NOx, SO_2, and PM are discussed in Chapters Two, Three, and Four, respectively. Pollutant emission controls are generally divided into three major types given in the following list.

- *Pre-combustion Controls*. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls*. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Data on costs of pollution control equipment taken from the literature are reviewed in the individual technology chapters. In Chapter Five, an existing model for the estimation of air pollution control equipment costs for coal-fired EGUs (CUECost) is applied to ICI boilers burning different fuels (coal, oil, wood) with appropriate caveats and assumptions to provide reasonable and approximate control costs for ICI boilers.

1.4 Chapter 1 References

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2 NOx CONTROL TECHNOLOGIES

2.1 Introduction

This brief introduction applies to chapters Two, Three, and Four, which discuss control technology options for ICI boilers for NOx, SO_2, and PM, respectively. However, these chapters are not intended to provide detailed descriptions of the many available technologies for each pollutant. Significant literature is available for that purpose; in the context of this report, these chapters are intended to provide the reader with a general understanding of concepts, performance, applicability, and costs of the main technologies available. Further, in recognition of the concern with climate change, a brief discussion of energy consumption (parasitic power) associated with major technologies is included.

Specifically with respect to the deployment and applicability of air pollution controls, comparisons between ICI boilers and EGUs are relevant because of the more widespread application of pollution control equipment in the EGU sector. This was discussed in some detail in Chapter One. In addition, a few considerations specific to certain technologies and strategies are discussed, as appropriate.

2.1.1 ICI versus EGU Boilers

In general, the greater proliferation of air pollution control technologies in the EGU sector, as opposed to the industrial sector, seems to be driven by three dominant, differentiating factors.

- Size difference and associated emissions between the two: Because EGUs are much larger than ICI boilers, they have been targeted for environmental regulatory controls more heavily over the years.
- Technology costs: While not universally true, ICI boilers often have constraints due to their smaller sizes, diversity of plant layouts, and urban settings, all of which can have a negative impact on the costs of applying some of the control technologies. Conversely, and equally important, opportunities for lower-cost applications to ICI boilers do exist as a result of the smaller sizes, such as in the ability to have systems pre-fabricated and ready to erect onsite, as opposed to on-site construction requirements often needed with larger systems for EGUs.
- Cost recovery: The two sectors are significantly different from a fundamental business view, with EGUs being regulated entities, as opposed to openly competitive markets that exist within the ICI boiler population. This is important in that it affects how business decisions are made in the two sectors, how capital equipment purchases are funded, and also how ICI plants are designed and operated.

2.1.2 Control Technologies' Impact on Efficiency and CO_2 Emissions

Air pollution control technologies and strategies can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative and it is a function of the type of technology, as well as fuel choices.

An extreme example of this is the control of SO_2 from a coal-fired unit by two significantly different approaches: in one case, the use of an energy–intensive FGD "scrubber" penalizes the efficiency of such unit by up to 2 percent, resulting in a corresponding increase in CO_2 emissions; a very different and contrasting case, in which the unit chooses to reduce its SO_2 generation by switching from coal to natural gas, yields a corresponding and substantial decrease in its CO_2 emissions. Similarly, an efficient Low-NOx Burner (LNB) may replace an older burner and increase unit efficiency, while reducing NOx emissions, whereas a SNCR or SCR also reduces NOx, but will have some inherent parasitic power requirement that will have a negative impact on overall efficiency (and emissions of CO_2).

These chapters primarily address control technology options, as opposed to fuel switching strategies, except for SO_2. Switching from high-sulfur oil to low-sulfur oil is also discussed in Chapter 3. CO_2 impacts are well established as a function of the carbon content of fuels. The same applies in the case of renewable, carbon-based fuels (biomass). However, with control technologies, the impacts can vary widely among technologies for the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. wet and dry scrubbers for SO_2).

In general, efficiency impacts from application of air pollution control technologies can be divided into two major general areas:

- Direct impact (positive or negative) on the combustion process itself (e.g., changes in concentrations of O_2 or CO and in the amount of unburned carbon (UBC) in ash)
- Parasitic power associated with the particular technology or its components (e.g., increased gas pressure loss, power requirements for pumps/fans)

This parasitic power is given here in terms of electric power (kW) per flue gas flow rate (acfm) or kW/1000 acfm. These units are appropriate for several reasons:

- Most ICI boilers do not produce electricity, hence, size is more universally characterized by a parameter other than electrical generation (e.g., flow rate);
- Most control technology suppliers rank their equipment size in terms of gas flow rate as this is the dominant parameter for gas handling equipment sizing;
- If the objective is to "correlate" this parasitic power loss to an equivalent CO_2 impact, it can be done simply by knowing the size (acfm) of the technology application and the CO_2 emission profile of the equivalent kW generation (or savings) to offset the parasitic power loss.

2.2 Discussion of NOx Control Technologies

2.2.1 NOx Formation

The formation of NOx is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form NOx. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NOx emissions.

2.2.2 NOx Reduction

As a result of complex interactions in the formation of NOx, a variety of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NOx emission control is to divide them into two major categories: (1) those that minimize the formation of NOx itself during the combustion process (e.g., smaller quantities of NOx are formed); and (2) those that reduce the amount of NOx after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach under the “umbrella” of combustion modifications whereas technologies in the second category are termed post-combustion controls. Within each of these two categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NOx control than the application of a stand-alone technology.

2.2.3 Other Benefits of NOx Control Technologies

Some NOx control technologies have shown the potential to promote the capture of mercury (Hg) from the flue gas. Examples include combustion modification technologies (e.g., Low-NOx Burners and Overfire Air – though potentially with higher levels of unburned carbon) and post-combustion technologies (SCR – through the oxidation of mercury, making it more soluble and amenable to capture in a downstream process such as a scrubber for SO_2). This suggests that strategic and economic analyses for NOx controls need to also consider the potential impacts on mercury removal.

2.3 Summary of NOx Control Technologies

2.3.1 Combustion Modifications

Combustion modifications can vary from simple “tuning” or optimization efforts to the deployment of dedicated technologies such as LNBs, Overfire Air (OFA) or reburn (most often done with natural gas and called Gas Reburn - GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to reductions in NOx emissions of 5 to 15 percent or even higher in cases where a unit was originally badly “de-tuned.” It is important to remember that optimization results are truly a function of the “pre-optimization” condition of the power plant or unit (just as the improvement in an automobile from a tune-up depends on how badly it was running prior to it), and as such have limited opportunity for substantial emission reductions.

Development of “intelligent controls” – software-based systems that “learn” to operate a unit and then maintain its performance during normal operation, can also go a long way towards keeping plants well tuned, as they gain acceptance and become common features in combustion control systems.

2.3.2 Low-NOx Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NOx during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as “fuel or air staging”).

Figure 2-1. Low-NOx burner [TODD Dynaswirl-LN™]

Figure 2-1 shows a gas/oil Low-NOx burner. These technologies are prevalent in the electric power industry as well as in ICI boilers at present and increasingly used by ICIs, even at small sizes (less than 10 MMBtu/hr). Competing manufacturers have proprietary designs, geared towards application for different fuels and boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NOx reductions of 30 to 65 percent from uncontrolled baseline levels. Again, the type of boiler and the type of fuel will influence the actual emission reduction achieved.

Particularly for gas-fired applications, as in the majority of ICI boilers, advanced Low-NOx Burners, often referred to as ultra Low-NOx Burners (ULNBs), are commercially offered by several companies. Ultra Low-NOx Burners are capable of achieving NOx emission levels on the order of single digits in ppm. As with all technologies, "pushing the envelope" on emission levels requires increasingly more careful suitability analyses as well as a good understanding of operational constraints. Conversely, the advent of these very low-emission burners (less than 10 ppm NOx), allows units to achieve very low emission rates at costs well below post-combustion alternatives like SCR.

All combustion modification approaches face a common challenge of striking a balance between NOx reduction and decrease in fuel efficiency. The concern is exemplified by typically higher CO and/or carbon levels in the fly ash, which reflect lower efficiency and also the contamination of the fly ash itself, possibly making it unsuitable for reutilization such as in concrete manufacturing. This is a bigger concern for large EGUs than for ICI boilers due to the much larger quantities of ash produced and the associated costs of disposal.

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss). Low-NOx Burners are applicable to most ICI boiler types, excluding stoker types and Fluidized Bed Combustion units (FBCs).

2.3.3 Reburn

Reburn, while generically included in the "Combustion Modification" category, is different from the other technologies in this group (LNBs/OFA) in that it "destroys" (or chemically reduces) NOx shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, however, natural gas is the most common) into the boiler above the main burner region. A portion of the heat input from the primary fuel is replaced by the reburn fuel. Subsequently, this "fuel-rich" environment reacts with and destroys the NOx formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as popular as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. *Figure 2-2* shows a typical reburn system applied to a stoker boiler.

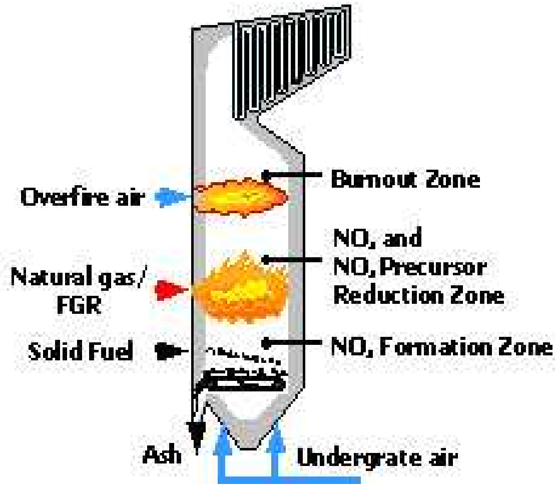

Figure 2-2. Gas reburn applied to a stoker boiler [www.gastechnology.org]

Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel, are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with a particular type of boiler – "Cyclone," – for which the previously mentioned technologies are not particularly well suited. However, this technology has been used only in large EGUs and is not a typical option for ICI boilers. Cyclone boilers are inherently high NOx emitters and are not an attractive option for new or retrofit units with increasingly lower NOx emission limits requirements.

Reburn performance has been shown to range from 30 to 60 percent reduction in NOx emissions, depending on such factors as reburn fuel type and quantity, initial NOx levels, boiler design, etc. Similar to the other combustion modification options, reburn can affect efficiency and fly-ash quality. As such, it requires the same optimum balance between NOx reduction and avoidance of negative impacts. On the other hand, reburn can be thought of as a "dial-in" NOx technology in that NOx reductions are, to a degree, a function of the amount of reburn fuel.

Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Reburn using coal or oil as the reburn fuel does not seem like a very attractive option for ICI boilers for technical reasons (boiler size, residence times), as well as the wider availability of similar performance options simpler to implement, such as LNBs. Gas reburn, while easier to implement, often has a prohibitive operating cost if, for example, natural gas is partially substituted for a less expensive primary fuel. Reburn is therefore an option for larger watertube-type boilers, including stokers, but require appropriate technical and economic analyses to determine suitability. Gas reburn has an impact on CO_2 emissions that is proportional to the type and quantity of fuels displaced (gas vs. coal or oil).

2.3.4 Post-Combustion Controls

Conventional, commercial post-combustion NOx controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NOx produced in the boiler to convert the NOx to harmless nitrogen and water. SNCR accomplishes this at higher

temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NOx. As noted below, SCR technology is capable of achieving much larger reductions in NOx emissions, higher than 90 percent, compared to the 30 to 60 percent reductions achievable by SNCR. *Figure 2-3* and *Figure 2-4* depict views of these two systems.

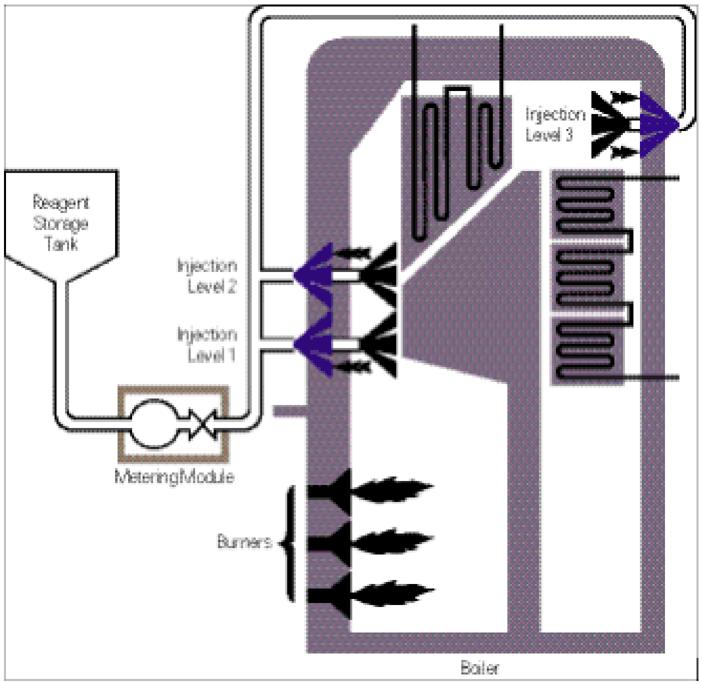

Figure 2-3. SNCR system schematic [FuelTech]

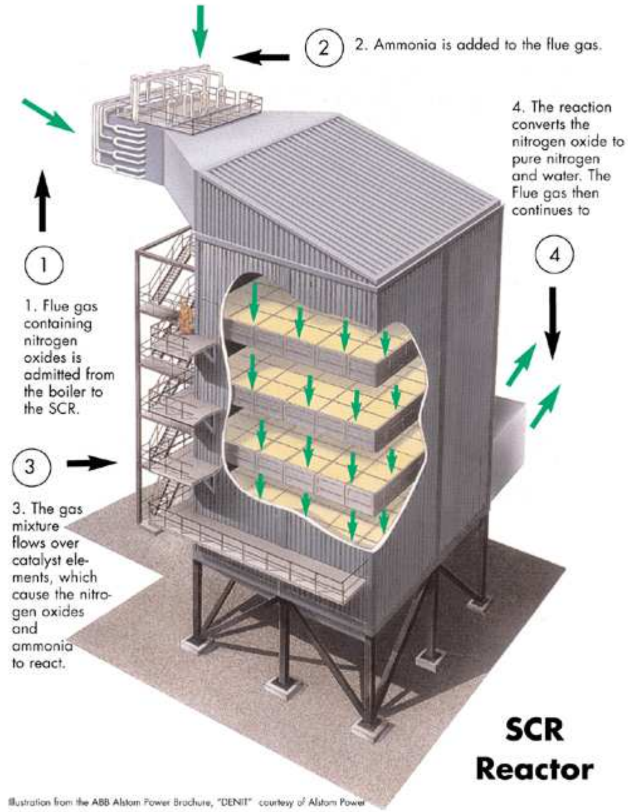

Figure 2-4. 3-D schematic of an SCR system [Alstom Power]

While the difference between the SNCR and SCR may seem minor, it yields significant differences in performance and costs. In the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the reaction vessel, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NOx); and finally, has lower NOx reduction capability (typically 30 to 50 percent, with some units achieving reductions in the 60 percent range). SCR, on the other hand, is capital intensive, but offers lower reagent costs and the opportunity for very high NOx reductions (90 percent or higher).

Costs are driven primarily by the consumption of the chemical reagent – usually (but not necessarily) urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NOx level and the desired percent reduction. It is also important to consider possible contamination of fly ash (in the case of coal firing) by ammonia making it potentially unable to be sold. This is, again, a bigger issue for larger EGU plants than for ICI boilers due to the size and quantities involved; as already stated, ICIs burning solid fuel do not typically sell their fly ash.

2.3.4.1 RSCR

Commonly, EGU boilers utilize SCR systems to reduce NOx emissions. However, a conventional SCR may not be cost-effective to retrofit into smaller units like ICI boilers because of the extensive modifications required to accommodate the unit. For some applications, the SCR may be located downstream of the particulate control equipment, where the flue gas temperature is much lower than the range of 650-750°F required for a conventional SCR (Toupin, 2007). These conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

If it is necessary to compensate for the reduction of flue gas temperatures, a regenerative selective catalytic reduction (RSCR^{TM}) system allows the efficient use of an SCR downstream of a particulate control device. The primary application of an RSCR system is the reduction of NOx emissions where the flue gas is typically at 300-400°F (Toupin, 2007). *Figure 2-5* illustrates the schematic and the actual RSCR system. *Figure 2-6* shows a block of ceramic heat exchanger.

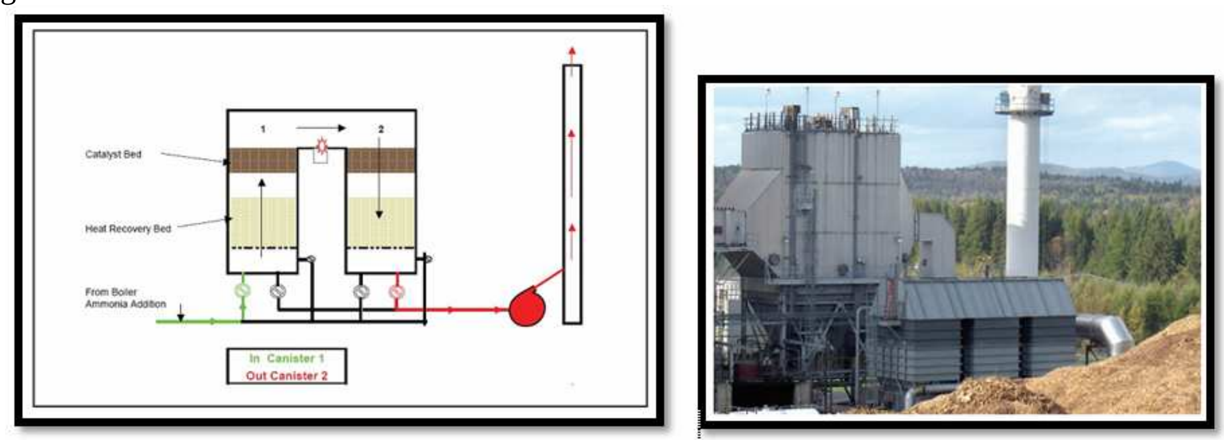

Figure 2-5. Schematic and actual RSCR [Toupin, 2007]

A direct-contact regenerative heater technology (i.e., burner), coupled with cycling beds of ceramic heat exchangers, is used to transfer heat to the flue gas. Additionally, some oxidation of CO to CO_2 in the flue gas occurs. The NOx reduction portion of the RSCR takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia can be used.

Figure 2-5 (left side) shows the working principles of the RSCR. Essentially, the flue gas in the space between the two canisters (called the retention chamber) is heated by the burner to make up for heat loss through the walls of the canisters and inefficiency in the ceramic heat transfer modules. This raises the temperature in the retention chamber by about 10-15ºF. The gas flows into the second canister, through the catalyst, and passes through the second ceramic module, which absorbs heat from the hot flue gas. Once this cycle is completed, the flow reverses, so that the second canister (which was just heated) becomes the inlet canister and the first canister becomes the outlet canister. The cycling between canisters accomplishes a similar function to the continuously rotating heating elements of a conventional regenerative air/gas heater.

Other components of the RSCR include the ductwork, fans, and the ammonia delivery system. Ductwork must be adequately sized to provide sufficient distance for ammonia mixing

and to minimize pressure drop. For the ceramic heat exchanger, factors that need to be taken into consideration during the design process are gas-side pressure drop, thermal efficiency, and cost. A large bed face area reduces the pressure drop and operating cost but increases capital cost. The ammonia delivery system consists of ammonia pumps, storage tanks, interconnecting piping, and a control system. The pump typically does not exceed one horsepower and often a redundant pump is provided to assure continuity in system operation [Toupin, 2007].

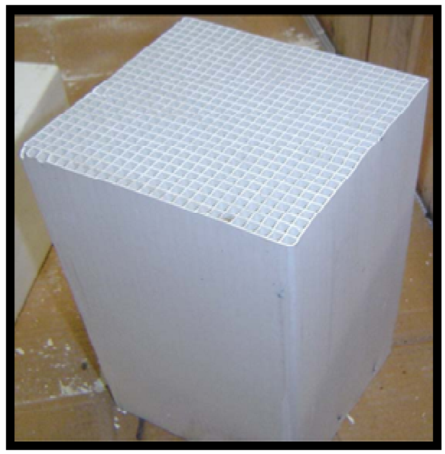

Figure 2-6. Block of monolith ceramic heat exchanger [Toupin, 2007]

The RSCR combines a regenerative thermal oxidizer (RTO) (e.g., retention chamber burner) with SCR technology. This ability to control flue gas temperatures allows for high NOx reduction under varying temperature conditions. *Table 2-1* shows the expected reduction in NOx and CO emissions [BPEI, 2006]. This study indicated that the RSCR is able to reduce NOx by 60 to 75 percent and CO by about 50 percent.

Table 2-1. CO and NOx reduction using RSCR [Source: BPEI 2006]

	Typical Stoker Design	**CO and NOx Reductions from Baseline**
Steam Flow lbs/hr x 10^3	100 – 500	
Steam Press, psi	600 – 900	
Steam Temp., °F	955 – 1000	
Unburned Combustibles Boiler Efficiency Loss (%)	1.0 – 1.5	
Furnace Retention sec.(1)	3.0	
Grate Heat Release Btu/hr-ft	850,000 maximum	
Emissions:		
CO lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.30 (122 – 370)	Base
CO **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.05 – 0.15 (61 – 185)	(-50%)
NOx lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.15 – 0.25 (112 – 186)	Base
NOx **w/SNCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.17 (75 – 130)	(-30 to 40%)
NOx **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.06 – 0.075 (45 – 56)	(-60 to 75%)

Additionally, the heat exchanger part of the RSCR has a thermal efficiency of about 95 percent, which translates to fuel savings. Traditional technologies that utilize Ljungstrom or plate type heat exchangers for heat recovery and duct burners to reach the catalyst operating temperature are typically in the range of 70 to 75 percent thermal efficiency.

An analysis performed by BPEI on a typical 25 MW plant with a 75 percent reduction in NOx shows a cost effectiveness of $4,514 per ton of NOx removed. The cost breakdown is tabulated below in *Table 2-2*.

Table 2-2. RSCR cost efficiency [BPEI, 2008]

Plant Overview:	
Plant Gross MW	25
GROSS HEAT INPUT, MMBTU/HR	321
TYPICAL UNCONTROLLED NOx, LB/MMBTU	0.25
TYPICAL CONTROLLED NOx, LB/MMBTU	0.065
NOx REMOVED, TONS/YEAR	249.4
RSCR Cost:	
AMMONIA COST, $/TON NOx	$ 419
NATURAL GAS, $/ton NOx	$ 404
POWER COST, $/TON NOx	$ 589
CATALYST COST, $/TON	$ 555
CAPITAL COST, $/TON	$ 2,546
TOTAL COST PER TON NOx REMOVED	$ 4,514

Two RSCR installations (15 and 50MW) are currently in operation in the Northeast. The 15 MW plant uses whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of the two installations was to qualify for the Massachusetts Renewable Energy Credits (RECs). The state requirement for qualifying for RECs imposed a NOx level of 0.075 lb/MMBtu or less on a quarterly average basis.

2.3.5 Technology Combinations

In theory, most of the technologies described above can be used together. However, NOx reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NOx levels entering the SCR/SNCR system. Another combination offered commercially is the hybrid SNCR/SCR concept, which uses the excess ammonia (ammonia “slip”) of the SNCR to promote additional NOx reduction in a downstream SCR catalyst.

2.4 Applicability to ICI Boilers

The NOx control technologies previously described are commercially available and are used extensively in EGUs, but most are also applicable to ICI boilers. Because conventional fuels (e.g., coal, oil, gas) as well as alternative fuels (e.g., wood, petroleum coke, process off-gases) emit NOx, these technologies are applicable to most boilers using various fuels. With the exception of FBC and Stoker boilers, LNBs are available and widely used for most combinations of boiler types and fuels. OFA and reburn as well as SNCR and SCR technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility. As already stated, these include available space, residence times and gas temperatures. Conversely, other than firetube type boilers, these technologies are potential candidates for the other boiler types including stokers and FBCs. Finally, the RSCR may offer advantages for applications where low flue gas temperatures are present and a conventional SCR may be more costly to implement.

2.5 Efficiency Impacts

The NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the noted exception for reburn when displacing coal or oil with natural gas. This is because combustion modification technologies do not impose any significant parasitic energy consumption (auxiliary power). Note that combustion modification technologies can affect the resulting combustion conditions in addition to the desired reduction in NOx emissions. These impacts are reflected in varying temperatures, oxygen levels, and CO/UBC, all of which affect combustion efficiency as discussed previously. However, we do not attempt to quantify these impacts. The overriding assumption is that these NOx control technologies, once deployed, are optimized such that the resulting NOx emissions are achieved without compromising the above parameters (or at least their combined effects).

With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy impact on the host boiler. The losses attributable to these technologies include the following:

- For SNCR
  - compressor power (air atomization/mixing)
  - steam (if steam atomization/mixing)
  - dry gas loss (air injection into furnace)
  - water evaporation loss
- For SCR
  - compressor
  - reactor pressure loss
  - steam (sootblowing)

Table 2-3 summarizes the key parameters for major NOx control technologies.

Table 2-3. Summary of NOx control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impacts (kW/1000 acfm)	Comments
LNB	All except Stokers, FBC	30 – 60 (<10ppm possible on gas)	NA	Assumed not to have negative impact on $CO/UBC/O_2$
OFA	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
Reburn	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
SNCR	All except firetube (Must have adequate temperature window)	30 - 70	1 - 2	Compressor/vaporization losses
SCR	All (Most likely for larger coal units where LNBs cannot reach very low NOx levels)	60 - 90	0.5 – 1 (gas) 2 - 4 (oil/coal)	Pressure loss/steam

2.6 NOx Control Costs

The following tables summarize published NOx control costs for ICI boilers reported in the literature [US EPA, 1996; NESCAUM, 2000; Khan, 2003; US EPA, 2003; MACTEC, 2005; Whiteman, 2006]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of NOx removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some operating costs. Costs of reagents and fuels (e.g., ammonia, natural gas) and consumables (e.g., SCR catalyst) change with time, but not always at the general rate of inflation. Some of these costs have increased at rates higher than the general rate of inflation. Thus, cost effectiveness values (or operating costs) from before 2005 have not been reported.

Table 2-4 summarizes the published NOx control costs for combustion modification technologies. The cost of the installation of low-NOx combustion technology depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity (*Figure 2-7*). Smaller boilers (10 to 50 MMBtu/hr) are often firetube or packaged watertube, whereas larger oil and gas boilers are more likely to be field-erected watertube boilers. Coal-fired boilers can be stokers, pulverized coal (PC), or cyclones. Combustion modification technologies therefore need to be evaluated on a case-by-case basis, taking into account both the fuel and the design of the combustion system. For the substantial majority of the estimates for ICI boilers, capital costs are in the range of $1,000 to $6,000 per MMBtu/hr. Cost effectiveness values, where available, are generally in the range of $1,000 to $7,000 per ton of NOx removed.

Table 2-4. NOx control costs for combustion modifications applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
Overfire Air	15-30	Coal	500	$2,682	1996		1
Fuel-Lean GR	35%	Coal	350	$1,302	1999		2
Gas Reburn	55%	Coal	500	$2,604	1999		2
LNB	25%	Coal	350	$6,378	1999		2
LNB	36.0%	Coal	350	$6,378	1999		2
LNB	50%	Coal	500	$8,464	1996		1
LNB	51%	Coal	100	$9,287	1999		6
LNB	51%	Coal	250	$7,055	1999		6
LNB	51%	Coal	1000	$4,654	1999		6
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,383	3
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,988	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$2,636	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$3,101	3
LNB	40%	Pulv. Coal	250	$346-$3,610	2005	$749-$3,393	3
LNB	45.0%	Resid. Oil	250-FT	$5,088	2005	$6,361-$7,483	3
LNB	50%	Resid. Oil	250-WT	$5,088	2005	$4,691-$5,519	3
LNB	40%	Resid. Oil	250	$346-$5,088	2005?	$1,505-$6,813	3
LNB	45%	Resid. Oil	10	$7,617	1996		1
LNB	45%	Resid. Oil	50	$3,021	1996		1
LNB	45%	Resid. Oil	150	$1,563	1996		1
LNB	45%	Dist. Oil	10	$7,617	1996		1
LNB	45%	Dist. Oil	50	$3,021	1996		1
LNB	45%	Dist. Oil	150	$1,563	1996		1
LNB	25%	Gas	350	$6,378	1999		2
LNB	40%-55%	Gas	10	$7,617	1996		1
LNB	40%-55%	Gas	50	$3,021	1996		1
LNB	40%-55%	Gas	150	$1,563	1996		1
LNB+FGR	50%	Pulv. Coal	250	$930-6,629	2005	$1,482-$3,582	3
LNB+FGR	72%	Pulv. Coal	250	$930-6,629	2005	$1,029-$2,488	3
LNB+FGR	50%	Resid. Oil	250	$930-6,629	2005	$2,977-$7,197	3
LNB+FGR	72%	Resid. Oil	250	$930-6,629	2005	$2,068-$4,998	3
LNB+OFA	51%-65%	Coal	100	$9,287	1999		6
LNB+OFA	51%-65%	Coal	250	$7,055	1999		6
LNB+OFA	51%-65%	Coal	1000	$4,654	1999		6
LNB+OFA	30%-50%	Oil	100	$3,258	1999		6
LNB+OFA	30%-50%	Oil	250	$2,474	1999		6
LNB+OFA	30%-60%	Oil	1000	$1,633	1999		6
LNB+OFA	60%	Gas	100	$3,258	1999		6
LNB+OFA	60%	Gas	250	$2,474	1999		6
LNB+OFA	60%	Gas	1000	$1,633	1999		6

Table 2-4 [continued]

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
ULNB	46%	Pulv. Coal	250	$1,364	2005	$1,876	3
ULNB	63%	Pulv. Coal	250	$1,364	2005	$933	3
ULNB	72%	Pulv. Coal	250	$1,364	2005	$619	3
ULNB	75%	Pulv. Coal	250	$1,364	2005	$784	3
ULNB	85%	Pulv. Coal	250	$1,364	2005	$692	3
ULNB	75%	Resid. Oil	250	$1,364	2005	1575	3
ULNB	85%	Resid. Oil	250	$1,364	2005	1390	3
ULNB	80%	Dist. Oil	24.5	$8,619	2005	17954	3
ULNB	80%	Dist. Oil	70	$2,280	2005	5756	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4751	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4564	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

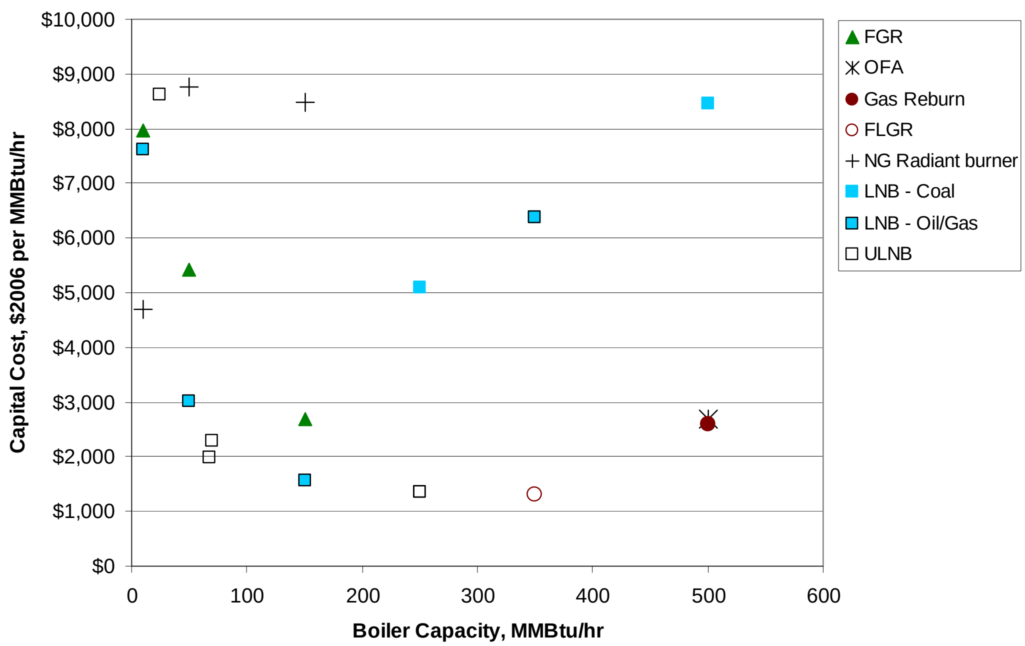

Figure 2-7. Capital cost for NOx control for combustion modification applied to ICI boilers as a function of boiler capacity

Table 2-5. NOx control costs for SNCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SNCR	30%-70%	Coal	500	$2,044	1996		1
SNCR	40%	Coal	100	$6,717	1999		6
SNCR	40%	Coal	250	$5,102	1999		6
SNCR	40%	Coal	1000	$3,366	1999		6
SNCR	30%-70%	Resid. Oil	50	$4,297	1996		1
SNCR	30%-70%	Resid. Oil	150	$4,297	1996		1
SNCR	35%		350	$2,862	1999		2
SNCR			21	$17,101	2006	$3,718	4
SNCR			120	$6,377	2006	$2,231	4
SNCR			240	$4,493	2006	$1,821	4
SNCR			387	$2,899	2006	$1,564	4
SNCR			543	$2,319	2006	$1,538	4
SNCR			844	$1,449	2006	$1,346	4
SNCR	40%	Oil	100	$5,205	1999		6
SNCR	40%	Oil	250	$3,954	1999		6
SNCR	40%	Oil	1000	$2,608	1999		6
SNCR	30%-70%	Dist. Oil	50	$4,297	1996		1
SNCR	30%-60%	Natural Gas	50	$4,297	1996		1
SNCR	40%	Gas	100	$5,372	1999		6
SNCR	40%	Gas	250	$4,082	1999		6
SNCR	40%	Gas	1000	$2,693	1999		6
LNB+SNCR	50%-89%	Pulv. Coal	250	$2,064-6,829	2005	$1,409-$4,473	3
LNB+SNCR	50%-89%	Resid. Oil	250	$2,064-6,829	2005	$2,229-$7,909	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

Table 2-5 summarizes the published NOx control costs for SNCR applied to ICI boilers. As with combustion modifications, the capital cost of SNCR systems is sensitive to the type of combustion system. As long as the boiler has sufficient space for installation of injection lances and mixing of reagent and flue gas (at the appropriate temperature), the capital costs should not depend on the fuel burned. The relationship between capital cost and boiler capacity is shown in *Figure 2-8*. Except for the 1996 EPA estimates for gas and oil boilers, there is a pronounced effect of boiler capacity on capital cost. The graph shows that fuel type is probably secondary to boiler capacity, although there will be an indirect effect of fuel, because fuel type influences the design of the combustion system. The cost effectiveness for SNCR was given by ICAC [Whiteman, 2006] without regard to fuel type and by MACTEC [2005] for coal and residual oil.

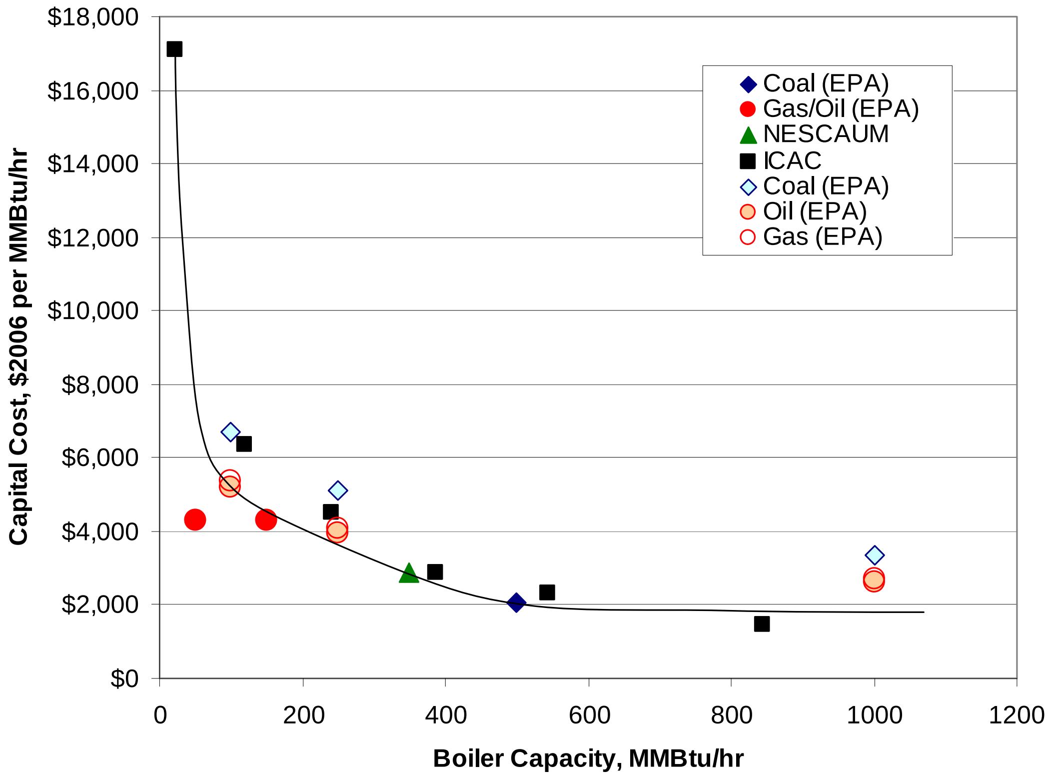

Figure 2-8. Capital cost for NOx control for SNCR applied to ICI boilers as a function of boiler capacity

Table 2-6 summarizes the published NOx control costs for SCR. The relationship between capital cost and boiler capacity is shown in *Figure 2-9*. The capital cost of SCR systems is sensitive to the type of fuel and to the level of NOx reduction desired, but not to the combustion system. The volume of catalyst required for an SCR installation depends on the level of desired NOx reduction and on the fuel. Coal-fired power plant applications are the most expensive, since the flue gas entering the SCR contains fly ash, which affects the design of the catalyst. The capital cost for a given fuel and boiler size can vary (see, for example, the variation in capital costs reported for coal application). When an SCR must be retrofit, the cost of the installation depends on the configuration of the specific system. Because the amount of

ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

Table 2-6. NOx control costs for SCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SCR	80%	Coal	*350*	$12,755-19,133	1999		2
SCR	80%-90%	Coal	500	$15,365-16,145	1996		1
SCR	70%-90%	Pulv. Coal	250	$1,666-13,881	2005	$2,233-$7,280	3
SCR	80%	Coal	100	$18,574	1999		6
SCR	80%	Coal	250	$14,110	1999		6
SCR	80%	Coal	1000	$9,309	1999		6
SCR	80%	Oil	100	$14,116	1999		6
SCR	80%	Oil	250	$10,723	1999		6
SCR	80%	Oil	1000	$7,075	1999		6
SCR	--	Oil	--	$5,102-7,653	1999		5
SCR	70%-90%	Resid. Oil	250	$1,666-13,881	2005	$4,363-$14,431	3
SCR	80%-90%	Resid. Oil	50	$8,359	1996		1
SCR	80%-90%	Resid. Oil	150	$4,909	1996		1
SCR	80%-90%	Dist.	50	$8,359	1996		1
SCR	80%-90%	Dist.	150	$4,909	1996		1
SCR	80%	Gas	100	$10,216	1999		6
SCR	80%	Gas	250	$7,760	1999		6
SCR	80%	Gas	1000	$5,120	1999		6
SCR	80%	Gas	100	$9,566	1999		2
SCR	80%	Gas	350	$7,015	1999		2
SCR	80%-90%	Natural Gas	50	$8,359	1996		1
SCR	80%-90%	Natural Gas	150	$4,909	1996		1
SCR	80%	Wood	350	$6,378-7,653	1999		2
SCR	74%	Wood	321	$1,978	2006	$4,514	7

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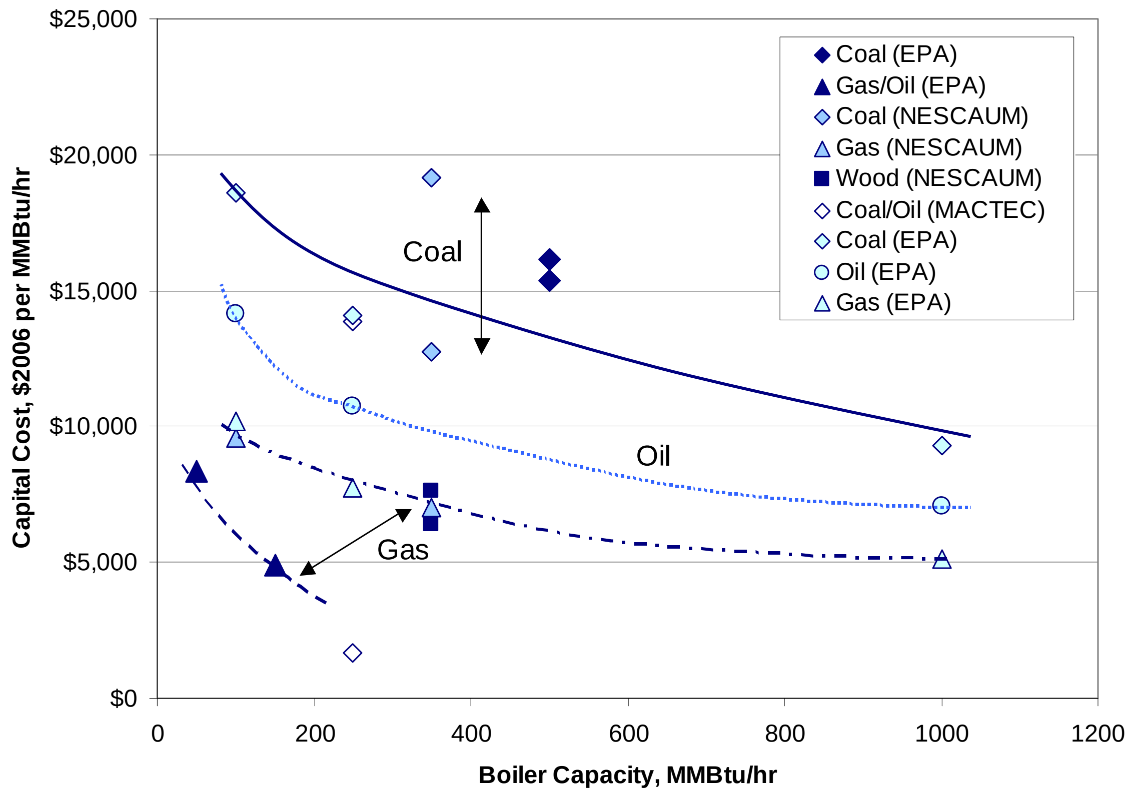

Figure 2-9. Capital cost for NOx control for SCR applied to ICI boilers as a function of boiler capacity

2.7 Chapter 2 References

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3 SO_2 CONTROL TECHNOLOGIES

3.1 SO_2 Formation

SO_2 is an undesirable byproduct of the combustion of sulfur-containing fossil fuels. SO_2, like NOx, is a precursor to ambient fine particles: Thirty to 50 percent of ambient fine PM mass in the eastern U.S. is attributable to sulfate derived from SO_2. SO_2 is a significant contributor to wet and dry acid deposition on various ecosystems (lakes, streams, soils, and forests). Various coals in the U.S. can have 1 to 3 percent (by mass) sulfur; residual oil (No. 6 oil) can have sulfur contents of 2 percent and higher. Distillate oils are generally lower in sulfur content (less than 0.5 percent by mass). Natural gas has essentially zero sulfur content. However, unlike nitrogen in coal or oil, essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics). This means that the relationship between sulfur content in the fuel and SO_2 emissions is much more direct and linear than that between fuel nitrogen and NOx emissions, and as such, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal or from higher-sulfur oils to lower-sulfur oils) are directly proportional to the difference in sulfur contents of fuels.

Another important difference is that this relationship is, for all practical purposes, independent of the type of boiler technology. Two exceptions to this include the high–alkaline nature of ash in some sub bituminous coals, which causes a portion of the sulfur in the coal to react and form various sulfate salts (mostly calcium sulfate); another is the combustion of coal in fluidized bed combustion (FBC) boilers where the lower temperatures of combustion and the use of alkaline material (e.g., limestone) in the "bed" promote the reaction of SO_2 with calcium to form sulfate, thereby reducing the net emissions of SO_2. In practical terms, this means that most solid- and liquid-fuel-fired systems produce SO_2 emissions proportional to their sulfur content, whereas natural gas combustion produces essentially no SO_2.

Additionally, despite the much smaller quantities of SO_3 formed in comparison to SO_2, as noted above, SO_3 presents both operational and environmental challenges. Operationally, SO_3 is a concern because if the temperature of the back-end flue gas handling equipment (e.g., ducts, particulate control devices, scrubbers) falls below the acid dew point, corrosion and material deterioration can result. From an environmental perspective, nucleation and condensation of ultra-fine sulfuric acid particles formed from the SO_3 present in the flue gas can contribute to the primary emissions of fine PM from the stack into the atmosphere.

3.2 SO_2 Reduction

As a result of the relationship between fuel sulfur content and SO_2, SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. This is accomplished by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers" and are usually

described in terms of the process conditions (wet vs. dry), methods for gas-sorbent contact (e.g., absorber vessel vs. duct for dry sorbent injection), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction, and the use of enhancing additives. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability to ICI boilers, and data on performance and cost. For a more detailed description of FGD technologies, see Srivastava [2000].

As noted earlier, SO_2 control strategies can also include fuel switching (from high-sulfur coal to low-sulfur coal or from high-sulfur oil to low-sulfur oil/natural gas). While not considered a “technology,” switching from a higher-sulfur fuel to a lower-sulfur one requires considerable cost and operational analysis. Major issues include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

3.3 Other FGD Benefits

Significant attention has been given recently to the issue of mercury emissions from EGUs and ICI boilers. It is relevant to note that some FGD technologies have been shown to capture mercury from the flue gas [Jones and Feeley, 2008] by absorbing the water-soluble oxidized forms of mercury from the flue gas. Both wet and dry SO_2 control processes have been and are being tested to determine their mercury capture potential. This suggests that strategic and economic analyses for SO_2 control technologies need to consider the potential side-benefit of mercury removal as well.

3.4 Summary of FGD Technologies

A brief overview of FGD technologies is provided here to give the reader a broad perspective on SO_2 controls.

3.4.1 Wet Processes

Wet FGD (WFGD) or “wet scrubbers” date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s [NESCAUM 2000]. They represent the predominant SO_2 control technology in use today with over 80 percent of the controlled EGUs capacity in the world and the U.S. [EPA 2000].

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield >90 percent SO_2 capture. Currently, advanced scrubber designs for EGUs have eliminated not only many of the early operational problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with the technology being capable of well over 95 percent SO_2 control [Dene *et al.*, 2008]. *Figure 3-1* provides a schematic view of a wet scrubber.

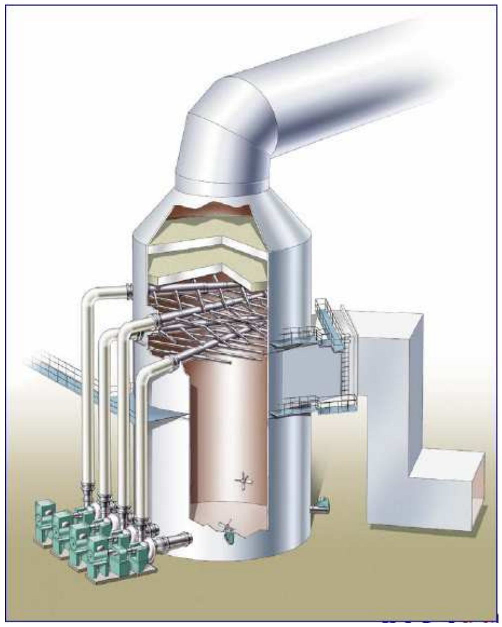

Figure 3-1. Schematic of a WFGD scrubber [Bozzuto, 2007]

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate, ammonia, and even seawater-based processes are all commercially available. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, and efficiency targets.

Technology costs have changed over time, as expected, reflecting changes in market conditions, labor and raw material costs, local, state, regional, and federal regulatory drivers, and site-specific considerations. Recently, capital costs have trended upward after a downward trend in the mid-late 1990s. These fluctuations have in large part, been driven by labor and material costs, the global nature of technology markets, and regulatory changes within the electric power sector [Sharp, 2007; Cichanowicz, 2007].

3.4.2 Dry Processes

Conventional dry processes include spray dryers (SDs) or “dry scrubbers” and Dry Sorbent Injection (DSI) technologies, and are shown in *Figure 3-2* and *Figure 3-3*, respectively. The technologies are referred to as “dry” because the SO_2 sorbent, while it may be injected as a slurry or a dry powder, is finally dried and collected in a conventional particulate control device, a fabric filter, or an ESP.

SD refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber vessel. DSI technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the “reactor,” and several configurations are possible based on the temperature window desired. This can occur at the furnace (1800-2200ºF), economizer (800-900ºF), or in a low-temperature duct (250-300ºF). In addition,

another common feature of dry scrubbing systems is the need for the particulate control equipment downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (although, depending on the application, ESPs may be used) that are not only efficient collectors of fine particulates, but can also provide some additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the bags. Dry processes are more compatible with low- to medium-sulfur coals because of the need to limit solid concentrations in the slurry below a threshold for adequate atomization and the need to limit the amount of solids collected in an existing particulate control device. This requirement precludes higher sulfur fuel applications where the required amount of reagent would be above that threshold. Therefore, high-sulfur applications are more typically associated with wet FGDs.

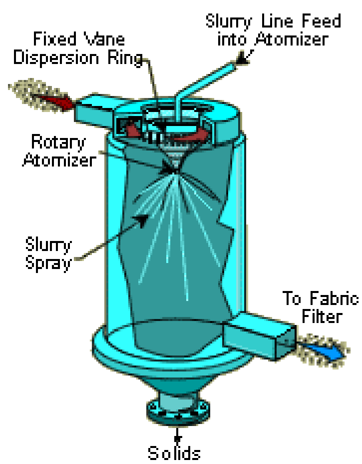

Figure 3-2. Schematic of a spray dryer [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

It is relevant to note that DSI technology did not gain any meaningful market penetration as part of the EGU compliance options to meet the requirements of the 1990 CAAA (Title IV) "acid rain" legislation for reducing emissions of SO_2. The large number of wet FGD installations in response to the Clean Air Act of 1970, and creation of "emission allowances," combined with the trend to switch fuels (mostly to low-sulfur Powder River Basin or PRB coal) in response to the 1990 CAAA, help explain this situation. However, more recently, interest in DSI technology applications for ICI boilers has been renewed and companies are "revamping" the knowledge base for DSI.

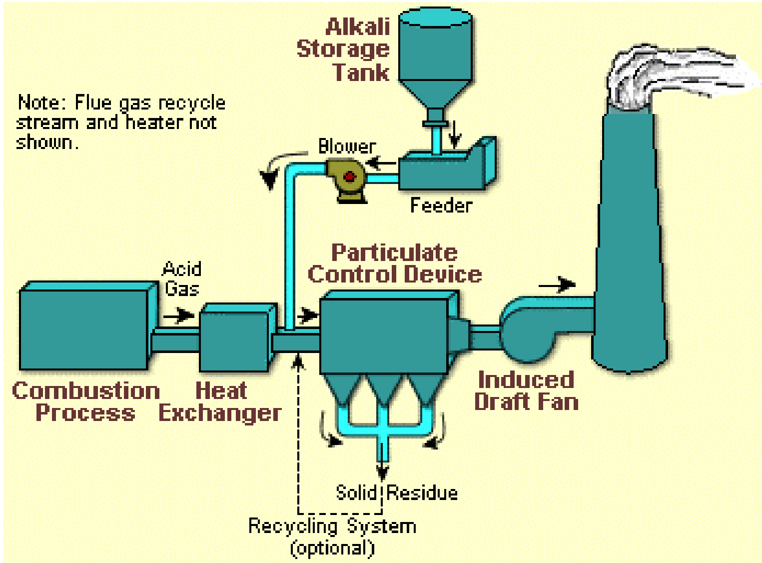

Figure 3-3. Dry Sorbent Injection (DSI) system diagram
[http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector. Companies such as O'Brien and Gere [Day, 2006; Day, 2007] and Siemens Environmental [Siemens, 2007] are marketing and deploying duct injection systems, and Nalco Mobotec [Haddad *et al.*, 2003] offers furnace sorbent injection (FSI) systems for ICI boilers. O'Brien and Gere, for example, have conducted over 5,000 hours of demonstrations at 15 different boilers since January 2005 to evaluate the viability, performance, and economics of DSI [Day, 2007]. These processes require relatively little new equipment and are thus suitable candidates for ICI boiler retrofit applications, where site constraints (e.g., space) are often critical.

Two examples of DSI systems are Furnace Sorbent Injection (FSI) in which hydrated lime is injected into the upper furnace of the boiler, and Lime Slurry Duct injection (LSDI) where atomized lime slurry is sprayed into the gas stream in the duct. FSI systems were first demonstrated in the 1980s on EGU boilers and are currently operating at ICI boilers [Dickerman, 2006].

FSI systems are capable of removing between 20 to 60 percent of the SO_2 and have shown removal percentages of as high as 90 to 99 percent for HCl and SO_3 [Haddad *et al.*, 2003]. The FSI systems also offer a low capital cost option and the attractiveness of quick cost recovery for ICI boiler sector [Dickerman, 2006].

The LSDI utilizes an atomized spray of lime slurry. The particles are subsequently captured in the downstream particulate collector. Sorbent particle size distribution is important for maximizing SO_2 capture while minimizing operational problems such as duct fallout and deposition.

LSDI systems have been utilized to mitigate plume generation from cement plants, and are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent [Dickerman, 2006].

In either case, both dry sorbent injection technologies offer an economical method for reducing emissions of SO_2. *Table 3-1* compares the FSI and LSDI systems for a 100 MW boiler, burning coal with one percent sulfur.

Table 3-1. Comparison of price for FSI and LSDI systems for a 100 MW coal-fired boiler [Dickerman, 2006]

Parameter	***FSI (Hydrated Lime)***	***LSDI***
SO_2 Removal	35%	50%
Reagent Cost ($\$10^3$/yr)	$1,400	$370
Parasitic Power ($\$10^3$/yr)	$182	$182
Disposal Cost ($\$10^3$/yr)	$168	$93
Subtotal ($\$10^3$/yr)	$1,750	$645
Capital Cost ($/kW)	$1,000,000 (10 $/kW)	$2,500,000 (25 $/kW)
Annual Capital Charge ($\$10^3$/yr)	$100	$250
Total Operating Cost ($\$10^3$/yr)	$1,850	$895
$/ton SO_2 Removed	$1,070	$311

Trona (sodium sesquicarbonate) is another reagent that has shown potential to reduce SO_2 emissions. A typical flow diagram is shown in *Figure 3-4* for injection of trona into a duct.

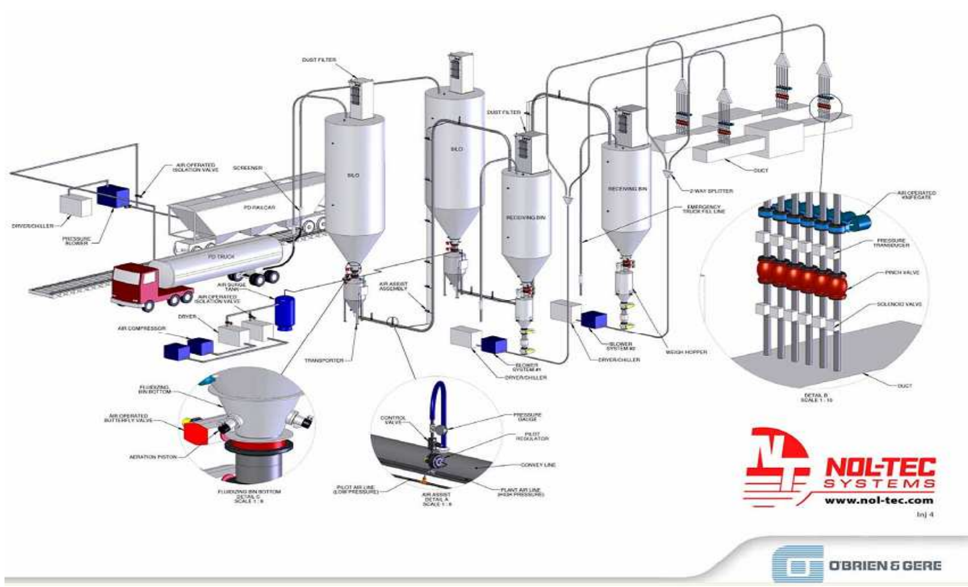

Figure 3-4. Flow diagram for trona DSI system [Day, 2006]

Trona's higher reactivity compared to lime helps it to offset the reaction stoichiometry advantage of lime. More importantly, due to the ability of trona to capture SO_2 when injected at higher temperatures [Cremer *et al.*, 2008], it is potentially applicable to many ICI boilers where flue gas temperatures may be higher that the desired ~300°F required for lime. *Figure 3-5* gives

some test data showing percent SO_2 reduction, [Day, 2006], averaged over several applications for units with ESPs.

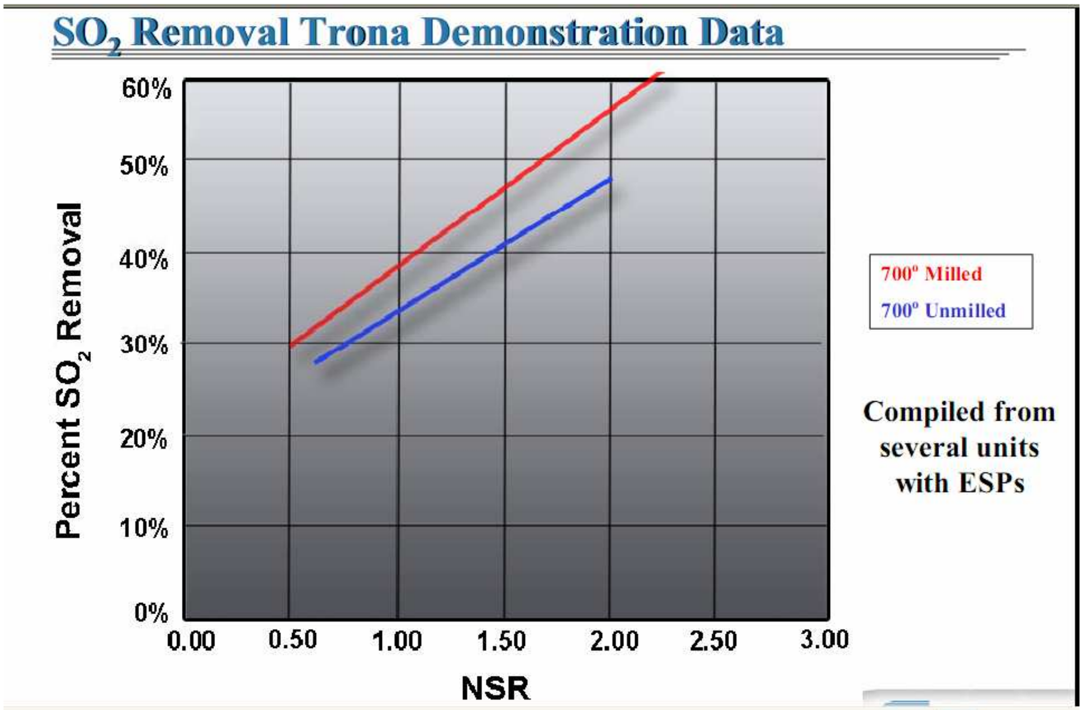

Figure 3-5. SO_2 removal test data [Day, 2007]

Figure 3-5 presents results for SO_2 reduction as a function of normalized stoichiometric ratio (NSR), which is the ratio of the reagent (trona in this case) to SO_2 in the flue gas. The two lines depict SO_2 reduction potential for two different sizes of trona at the same flue gas temperature of 700°F. Larger particles (unmilled) result in lower SO_2 reductions, as expected, relative to the milled condition (smaller particle size).

3.4.3 Other SO_2 Scrubbing Technologies

A number of other scrubber technologies have been developed for control of SO_2, but have not to date received significant market share. Among them are sodium- and ammonia-based wet scrubbing technologies. Some of these technologies, like the activated coke process [Dene, 2008], are regenerable (meaning the reagent can be regenerated and used repeatedly) and may produce useful byproducts, such as sulfuric acid, elemental sulfur, and ammonium sulfate. *Table 3-2* and *Table 3-3* present a comparison of the key performance characteristics and attributes for several alternative scrubbing technologies compared with conventional wet and dry scrubbers [Bozzuto, 2007].

Table 3-2. Comparison of alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Features	• High Efficiency • Low cost reagent • Byproduct flexibility	• Low investment cost • Dry byproduct • Small footprint • No liquid waste	• High value byproduct • Economics improved at high sulfur levels • Low operating cost	• Low investment cost • Operational simplicity
Pros	• Small flue gas flow • Operational simplicity required • Acute capital cost • Short evaluation period	• Low/medium sulfur fuel • Smaller flue gas flow • Short evaluation period	• High sulfur fuel • Larger flue gas flow • Gypsum market •Medium cost evaluation period	• High sulfur fuel • Larger flue gas flow • Fertilizer market
Cons	• Effluent discharge issue	• Limited landfill area • High lime/limestone cost ratio	• Acute capital cost sensitivity • Ultra-low PM emission requirements	• Acute capital cost sensitivity
Reagent	Limestone	Lime	Ammonia	Caustic, soda ash
Byproduct	Marketable gypsum or landfill	Landfill	Fertilizer	Sodium sulfate
SO_2 inlet	High	Low/medium	High	High
Removal Efficiency	>98%	90 – 95%	>98%	>98%

Table 3-3. Cost estimates for alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Capital Cost ($/acfm)	25 – 45	15- 25	35 – 60	10 – 20
Power Consumption (kW/acfm)	3-6	2	3-6	2-3
Reagent Cost ($/ton SO_2 removed.)	$15 – 25/ton	$60 – 75/ton	$80 – 105/ton	$100-130/ton
Byproduct Cost ($/ton SO_2 removed.)	$12 – 20/ton – disposal ($15/ton) – sale	$12 – 20/ton	$150 – 250/ton	??

3.5 Use of Fuel Oils with Lower Sulfur Content

Distillate fuel (No. 2 oil) is used in combustion systems in which an atomizer sprays droplets of oil into a combustion chamber and the droplets burn in suspension. Residual fuel oil (No. 6 oil) is also atomized and burned in ICI boilers. No. 6 oil is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of No. 6 oil in industrial combustion systems. A wide range of sulfur contents are available, from less than 0.3 wt% to greater than 3 wt%.

For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2. There is also an additional and important benefit of reduced emissions of $PM_{2.5.}$ There are generally costs associated with switching to lower-sulfur fuels, which will undoubtedly vary from region to region.

Table 3-4 shows an example of the stocks of the fuel oils available on the East Coast and in the U.S. in 2006, taken from the Energy Information Administration (EIA) Petroleum Supply Annual [US EIA, 2006]. Substantial stocks of low-sulfur No. 6 fuel oil (less than 0.3 percent sulfur) and of ultra-low-sulfur No. 2 fuel oil (less than 0.0015 percent sulfur) were available both in the U.S. and on the East Coast.

Table 3-4. Distillate and residual oil stocks in 2006 (x1000 barrels) [US EIA, 2006]

	East Coast		**U. S. Total**	
Distillate Fuel Oil	**4,174**		**31,318**	
0.0015% sulfur and under	1,856	(44%)	16,531	(53%)
Greater than 0.0015% to 0.05% sulfur	560	(13%)	6,223	(20%)
Greater than 0.05% sulfur	1,758	(42%)	8,564	(27%)
Residual Fuel Oil	**2,486**		**11,936**	
Less than 0.31% sulfur	869	(35%)	1,291	(11%)
0.31 to 1% sulfur	975	(39%)	2,544	(21%)
Greater than 1% sulfur	642	(26%)	8,101	(68%)

Figure 3-6 shows the prices for residual oil and distillate oil from 1983 through 2007. The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been narrowing in recent years. The price of distillate oil in recent years, however, has been at times twice as much as the price of residual oil. The EIA prices for residual oil do not include a breakdown for very low sulfur residual oil (less than 0.31 percent sulfur). However, the prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm S), low-sulfur (15-500 ppm S), and high-sulfur (>500 ppm S). These prices, shown in *Figure 3-7*, do not show much difference in price as a function of sulfur content of No. 2 oil.

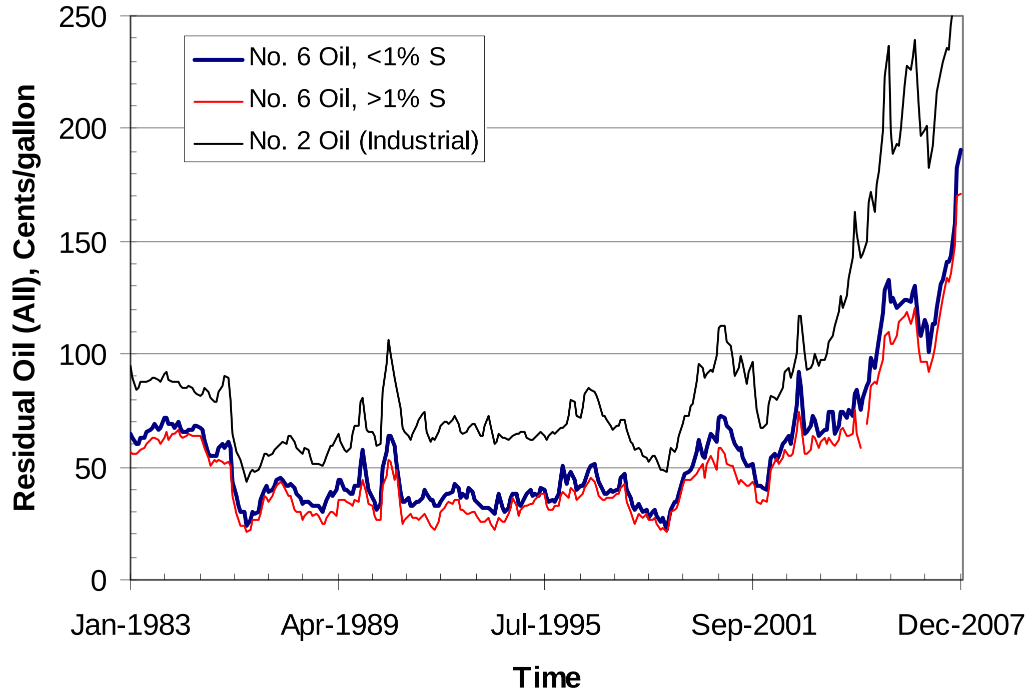

Figure 3-6. Industrial energy prices for No. 6 oil greater than 1 percent S, No. 6 oil less than 1 percent S, and No. 2 oil [Source: US EIA, 2008]

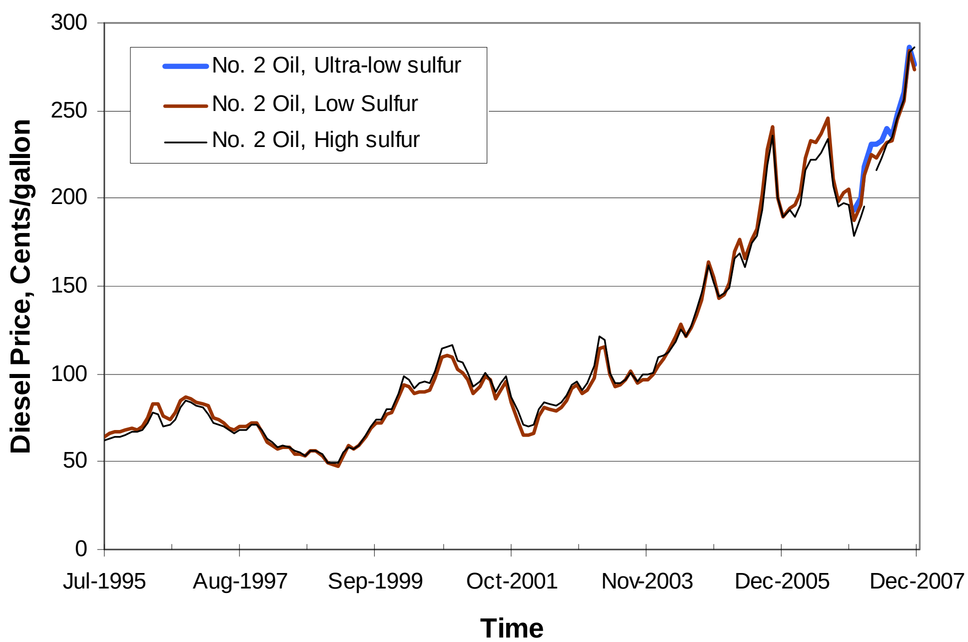

Figure 3-7. Industrial energy prices for No. 2 (distillate) oil [Source: US EIA, 2008]

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example, in which December 2007 fuel prices are used. If the high-sulfur residual oil is assumed to be 3 percent S, the low-sulfur residual oil is assumed to be 1 percent S, and the distillate oil is assumed to be 0.2 percent S, then the cost for fuel switching is shown in *Table 3-5*. These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in *Table 3-5* suggest that switching from a 3 percent sulfur residual fuel oil to a low-sulfur residual oil (1 percent S) would provide a cost-effective sulfur removal strategy at about $771 per ton of SO_2 removed. The cost of switching to distillate oil is estimated to be much higher than switching to low-sulfur residual oil, because the cost of distillate oil has been as much as twice that of residual oil in recent years. The cost effectiveness of a wet FGD for 90 to 99 percent SO_2 removal is in the range of $2,000 to $5,200/ton SO_2 (see Section 3.8). Thus, a switch to lower-sulfur fuel represents a cost-effective sulfur-compliance strategy for residual oil-fired boilers. The cost effectiveness (in dollars per ton of SO_2 removed) of switching from residual fuel oil to distillate fuel oil is not as attractive and is in the range of the cost effectiveness of installing a FGD or scrubber.

Table 3-5. Example of costs of switching to low-sulfur fuel oil [Fuel Prices from US EIA, 2008]

Fuel Switch	**SO_2 reduction**	**$/ton SO_2 removed (2007$)**
From 3% S to 1% Residual Oil*	66.7%	$771
From 3% S Residual to 0.2% Distillate**	93.6%	$5,335

*Assuming December 2007 prices for <1%S and >1%S residual oil
**Assuming December 2007 prices for >1%S and distillate oil

3.6 Applicability of SO_2 Control Technologies to ICI Boilers

The technologies described above are commercially available and are used extensively throughout the electric utility industry for coal-firing applications. The EGUs have deployed SO_2 controls (mostly wet and dry scrubbers) since the 1970s. ICI boilers firing coal are good candidates for the application of SO_2 control technologies. At least one oil-fired installation of a wet FGD has been noted in the literature [Caine and Shah, 2008]. Economics, however, will dictate preferred options on a case-by-case basis. It is likely that the higher capital-cost intensive technologies (e.g., wet and dry scrubbers) will be most attractive to larger ICI boilers, whereas the injection technologies (such as DSI) would likely be favored at smaller ICI boilers. The annualized cost of a wet FGD scrubber using wet sodium or alkaline waste can be lower relative to lime and limestone FGD, especially if low-cost waste disposal is available and the amount of SO_2 to be removed is small [Emmel, 2006]. This would suggest that smaller ICI boilers may not be good candidates for high capital-cost FGD systems. However, they should be good candidates for application of lower capital cost technologies such as DSI.

In terms of applicability, it is also important to recognize the impact of sulfur content of coal. Dry scrubbing has been typically restricted to low and medium sulfur coals (less than 2 wt% S) due to economic and technical considerations, including constraints associated with sorbent slurry concentration and adequate atomization performance. Lastly, while theoretically feasible, fluidized bed combustion (FBC) boilers are low emitters of SO_2 due to their inherent combustion process (bed temperature and composition), and are not likely candidates for SO_2 scrubber systems.

3.7 Efficiency Impacts

From the brief descriptions above, it should be clear that the common thread among the major SO_2 control technologies involves the reaction of SO_2 in the flue gas with a sorbent or reagent. The chemical reaction occurs either in a dedicated vessel (scrubber), or in the existing flue gas duct system. The major components affecting energy consumption for these systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. As expected, the energy penalties associated with a highly efficient (99 percent SO_2 reduction) wet scrubber are higher than for a less energy-intensive technology such as DSI.

The power consumption of SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. In other words, SO_2 control performance is related to reagent utilization, commonly referred to as liquid-to-gas (L/G) ratio for wet systems and normalized stoichiometric ratio or reagent (Ca or Na) to-sulfur ratio for dry technologies. This can be explained based on the fact that for a given SO_2 reduction level, lower quantities of reagent not only translate to lower reagent costs, but also to lower energy costs.

Table 3-6 summarizes performance and energy efficiency impacts for the three general SO_2 technologies discussed. It is important to note the values shown in the table, specifically in the "Energy Impact" column, represent nominal ranges based on generic combustion calculations and parasitic energy consumption for each technology. They are not site- or fuel-specific calculations, which are generally dependent on many variables, such as fuel composition, combustion and steam efficiencies, and operating conditions (e.g., excess air). However, these values represent broad, industry-wide averages for impacts of SO_2 control technologies on efficiency.

Table 3-6. Summary of energy impacts for SO_2 control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)
WFGD	Larger coal units, high sulfur coals, excluding FBC	90 - 95+	4 – 8+
Dry Scrubbers (SDs)	Larger units w/ low/medium sulfur coals, excluding FBC	70 – 90+	2 - 4
Duct Injection	Larger units w/ low/medium sulfur coals (FBC applications possible for additional "SO_2 trim")	30 – 60+	1 - 2

3.8 SO_2 Control Costs

Table 3-7 summarizes published SO_2 control costs for ICI boilers, as reported in the literature [Khan, 2003; US EPA, 2003; Whiteman, 2003; MACTEC, 2005]. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars/ton of SO_2 removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs, and reagents or consumables can make up a large portion of some of the operating costs. Costs of reagents and fuels (e.g., limestone, trona) change with time, but not always at the general rate of inflation. Thus, cost effectiveness values (or operating costs) from years before 2005 are not shown in the table. *Table 3-7* summarizes the published SO_2 control costs for a number of SO_2 control technologies.

A range of capital costs has been reported for sorbent injection technologies. *Figure 3-8* shows costs for dry duct injection (e.g., trona injection), wet duct injection (e.g., LSDI), and furnace sorbent injection (FSI). There was a large range of capital costs reported for dry sorbent injection. Wet sorbent injection (e.g., injection of hydrated lime slurry) was reported to have a significantly lower capital cost than dry sorbent injection. FSI capital costs were between dry and wet duct injection. The cost effectiveness (cost in dollars per ton of SO_2 removed) depends on the specific sorbent used and the stoichiometric ratio of sorbent to SO_2.

Table 3-7. SO_2 control costs applied to ICI boilers

Technology	SO_2 Reductio n Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
In-Duct Dry Sorbent Inj.	40%	High-S Coal	100	$34,228	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	250	$24,028	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	1000	$15,954	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	100	$22,953	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	250	$16,565	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	1000	$11,031	1999		1
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	100	$17,327	2003		3
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	250	$12,624	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	100	$8,663	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	250	$4,703	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	1000	$4,641	2003		3
Furnace Sorbent Inj.	70%	Coal	100	$26,609	2003		3
Furnace Sorbent Inj.	70%	Coal	250	$14,851	2003		3
Furnace Sorbent Inj.	70%	Coal	1000	$7,054	2003		3
Spray Dryer	90%	Coal	100	$69,744	1999		1
Spray Dryer	90%	Coal	250	$46,209	1999		1
Spray Dryer	90%	Coal	1000	$25,861	1999		1
Spray Dryer	90%	Coal	250	$13,300-188,820	2005	$1,712-3,578	4
Spray Dryer	95%	Coal	250	$13,300-188,820	2005	$1,622-3,390	4
Spray Dryer	90%	Oil	250	$13,300-188,820	2005	$1,944-5,219	4
Spray Dryer	95%	Oil	250	$13,300-188,820	2005	$1,841-4,945	4

Table 3-7 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet FGD	90%	High-S Coal	100	$81,939	1999		1
Wet FGD	90%	High-S Coal	250	$62,318	1999		1
Wet FGD	90%	High-S Coal	1000	$41,216	1999		1
Wet FGD	90%	Low-S Coal	100	$76,018	1999		1
Wet FGD	90%	Low-S Coal	250	$57,759	1999		1
Wet FGD	90%	Low-S Coal	1000	$38,122	1999		1
Wet FGD	90%	Coal	250	$11,507-172,672	2005	$2,089-3,822	4
Wet FGD	99%	Coal	250	$11,507-172,672	2005	$1,881-3,440	4
Wet FGD	90%	Oil	100	$69,848	1999		1
Wet FGD	90%	Oil	250	$53,066	1999		1
Wet FGD	90%	Oil	1000	$35,019	1999		1
Wet FGD	90%	Oil	250	$11,507-172,672	2005	$2,173-5,215	4
Wet FGD	99%	Oil	250	$11,507-172,672	2005	$1,956-4,694	4

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2. US EPA, *Air Pollution Control Technology Fact Sheet: Flue Gas Desulfurization (FGD - Wet, Spray Dry, and Dry Scrubbers*; EPA-452/F-03-034, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf
3. Whiteman, C., ICAC, "SO_2 Control Technology Cost Estimates for Industrial Boilers" memo to John Robbins, US EPA, December 12, 2003.
4. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

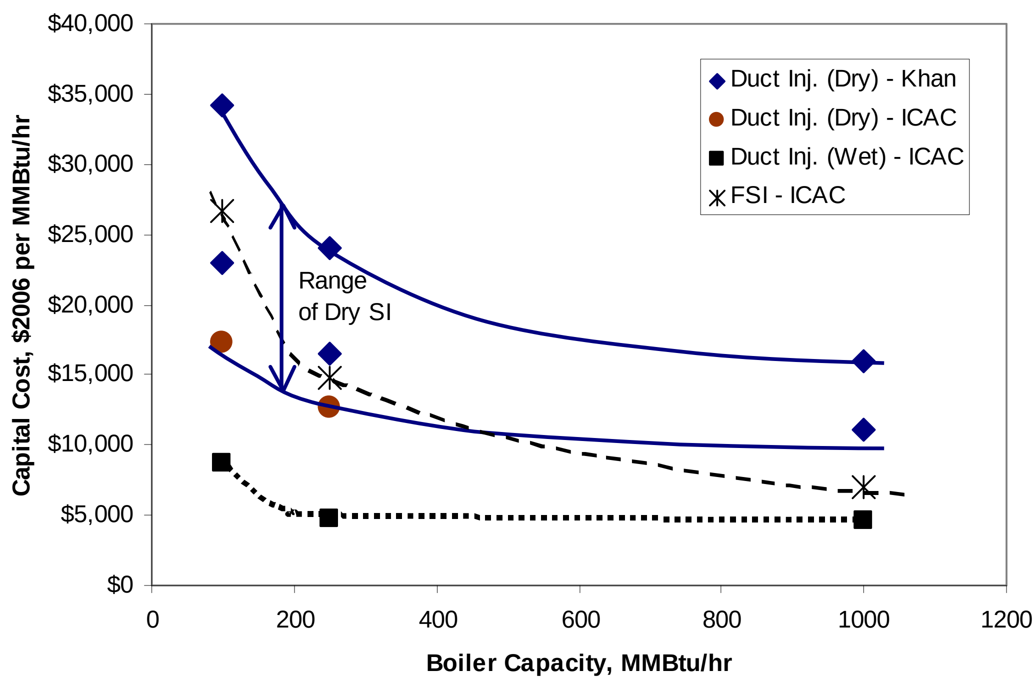

Figure 3-8. Capital cost for SO_2 control for dry sorbent injection applied to ICI boilers as a function of boiler capacity

Spray dryer (SD) technology has been widely applied to coal-fired EGUs. Estimates in the literature for SD technology for ICI boilers give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005]. *Figure 3-9* summarizes these capital costs for ICI boilers. Note that the MACTEC estimates at 250 MMBtu/hr boiler size assumed high and low equipment cost, but a detailed cost breakdown was not given.

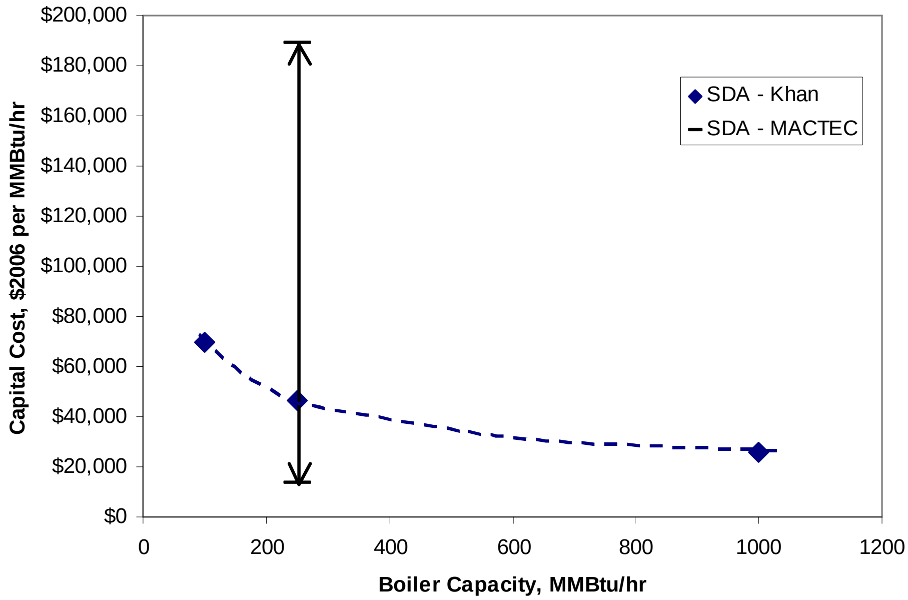

Figure 3-9. Capital cost for SO_2 control for Spray Dryer Absorber applied to ICI boilers as a function of boiler capacity

Wet FGD technology has been widely applied to coal-fired EGU boilers but rarely to ICI boilers, although at least one oil-fired installation has been noted in the literature [Caine and Shah, 2008]. The relationship between FGD capital cost and boiler capacity is shown in *Figure 3-10*. Estimates in the literature give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005], although these estimates are not always based on actual field installation data because installations of wet FGD technology on ICI boilers are few at present.

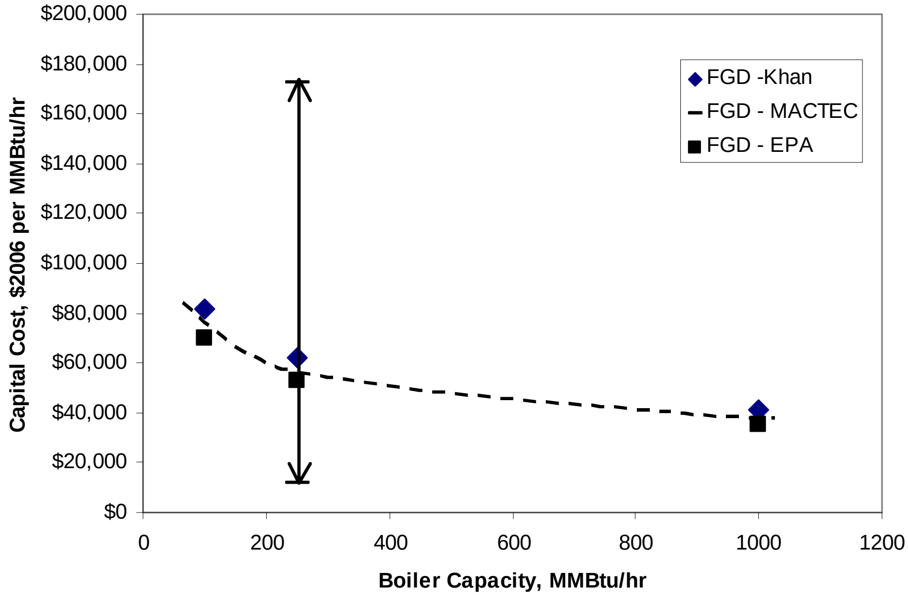

Figure 3-10. Capital cost for SO_2 control for wet FGD applied to ICI boilers as a function of boiler capacity

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4 PM CONTROL TECHNOLOGIES

4.1 PM Formation in Combustion Systems

PM emissions from combustion processes include primary and secondary emissions. Primary emissions consist mostly of fly ash. Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter (PM_{10} and $PM_{2.5}$). Fly ash refers to the mineral matter of the fuel, which typically includes some level of unburned carbon. ICI boilers burn a variety of fuels that contain ash and, as such, have PM emissions. Therefore, ICI boilers are candidates for PM controls.

Coal and oil contain non-combustible ash material. Other liquid or solid fuels (e.g., petroleum coke, wood) also contain ash. The quantity of ash in the flue gas depends on many factors, such as fuel properties, boiler design, and operating conditions. In dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash, and the remaining ash is collected as bottom ash. However, in wet-bottom, pulverized-coal-fired boilers, about 50 percent of the total ash exits the boiler as fly ash. In cyclone boilers (common in the EGU sector but not in the ICI population), most of the ash is retained as liquid slag, and the fly ash is only about 20 percent of the total ash. Fluidized-bed combustors (FBC) emit high levels of fly ash because the coal is fired in suspension and the ash is present in dry form. Stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers because combustion takes place in a relatively quiescent fuel bed.

In addition to the nitrates and sulfates mentioned as secondary PM, NOx control technologies that inject ammonia or amine-based reagents (SNCR and SCR) yield a certain amount of ammonia “slip,” which can also form fine particulate (ammonium sulfate) as the flue gas temperatures decrease towards the stack.

This section presents a brief description of the major primary PM technologies.

4.2 PM Control Technologies

PM control technologies have been commercially available and widely used in ICI and EGU boilers for many years. *Table 4-1* summarizes the main types of commercially available technologies.

Table 4-1. Available PM control options for ICI boilers

Technology	Description	Applicability	Performance
Fabric filters (Baghouse)	"Baghouses" made of close-knit fabrics remove particulates through filtration.	Primarily used in coal/wood fired industrial/utility boilers. Not used with oil boilers due to clogging.	>99% total and $PM_{2.5}$ removal
ESPs (Dry/Wet)	Charged particles attracted to oppositely charged plates. Collection method either wet/dry.	Widely used in coal applications. Suitable for oil, pet coke and waste solid fuels. Wet ESPs suitable for saturated flue gas.	Effectiveness depends on resistivity of particulates. Low sulfur can reduce performance of dry ESP. >99% reduction of total PM (dry/wet) and sulfuric acid mist and $PM_{2.5}$ (wet)
Venturi Scrubbers	Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste.	High pressure required for significant removal. Applicable to a wide range of fuels.	50% removal for fine particulates, 99% removal for large (>5 micron) particulates
Cyclones	Cyclones use aerodynamic forces to separate particles from the gas stream.	Widely applicable to all fuels.	70%-90% total PM potential

4.3 Description of Control Technologies

4.3.1 Fabric Filters

Fabric filters (also called baghouses) are essentially giant vacuum cleaners and very effective devices for collecting dry PM from flue gas. They are used in ICI and EGU applications, although less widely than ESPs. Separation occurs when the ash-laden flue gas passes through a porous layer of filter material. As the individual particles accumulate on the surface of the filter, they gradually form a layer of ash known as the "dust cake." Once formed, the dust cake provides most of the filtration. However, they are not particularly well suited for wet gas applications due to the negative impact of wet gas on the bag filters. *Figure 4-1* shows a photograph of the internal components of a fabric filter compartment with several individual bags and mounting mechanisms.

Figure 4-1. Photograph of fabric filter compartment with filter bags [Source: www.hamon-researchcottrell.com]

As shown in *Figure 4-1*, multiple bags are assembled in compartments to provide a large surface area for filtration. The large surface area is required to maintain acceptable pressure loss across the fabric. Groups of bags are placed in compartments, which can be isolated from one another to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse.

Baghouse size is typically defined in terms of "air-to-cloth" ratio, expressed in the units of velocity in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The size of the baghouse depends on the particulate loading and characteristics, and the cleaning method used.

The type of bag cleaning method employed characterizes baghouses. Cleaning intensity and frequency are important because the dust cake provides a significant fraction of the fine particulate removal capability of a fabric. Hence, too frequent or too intense a cleaning method may lower the removal efficiency. Conversely, if removal of this dust cake happens infrequently or inefficiently, the pressure drop will increase to unacceptable levels. The major cleaning methods are as follows.

- Reverse-air baghouse – In this case, the flue gas flows upward through the vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken off-line, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers.
- Pulse-jet baghouse – In this case, the dust is collected on the outside of the bags, which are mounted on cages to keep them from collapsing. Dust is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, allowing it to be done on-line. Because pulse-jet cleaning is more intensive than in reverse-air baghouses, the bags in a pulse-jet baghouse remain relatively clean, resulting in the ability to use a higher air-to-cloth ratio or a smaller baghouse compared to the reverse-air type.

Additionally, fabric filters can also be used in applications where fly-ash resistivity makes it difficult for collection with ESPs. Further, baghouses are capable of 99.9 percent removal efficiencies, as well as being able to remove the smaller size PM fraction ($PM_{2.5}$) more efficiently.

4.3.2 Electrostatic Precipitators

ESP's operate on the principle of electrophoresis by imparting a charge to the particulates and collecting them on opposed charged surfaces. Dry vs. wet ESPs refer to whether the gas is water-cooled and saturated prior to entering the charged collection area or is dry. *Figure 4-2* and *Figure 4-3* show schematic views of dry and wet ESPs, respectively. Older ESPs are often of the wire-pipe design, in which the collecting surface consists of one or more tubes (operated wet or dry). The wire-plate design is the other commonly used ESP design, as illustrated in the schematic in *Figure 4-2*.

In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 µm on a mass basis with wet ESPs being capable of such reductions well into the sub-micron level (0.01 µm) [Altman, 2001].

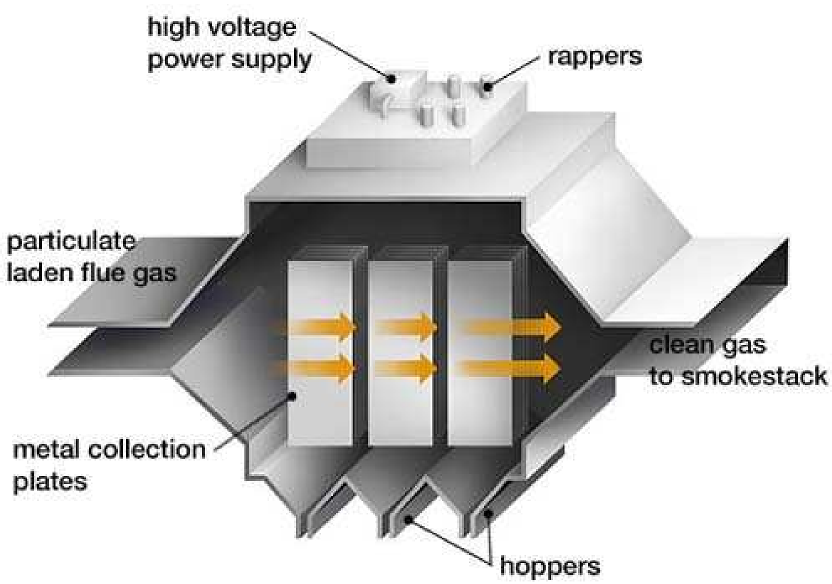

Figure 4-2. Side view of dry ESP schematic diagram [Source: Powerspan]

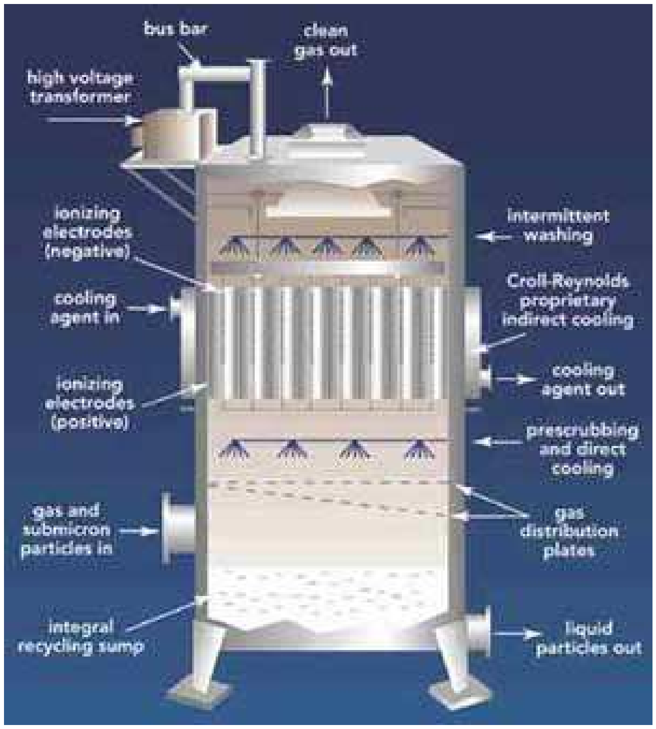

Figure 4-3. Wet ESP [Croll Reynolds]

Compared to fabric filters, ESPs affect the flue gas flow minimally, resulting in much lower pressure drops then an equivalent baghouse (typically less than two inches H_2O vs. greater than six inches H_2O for the fabric filter).

An electric field between high-voltage discharge electrodes and grounded collecting electrodes produces a corona discharge from the discharge electrodes, which ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The negatively charged particles are attracted to the collecting electrodes. To remove the collected fly ash, the collecting electrodes are rapped mechanically, causing the fly ash to fall into hoppers for removal.

A balance generally needs to be struck between higher voltages for higher particulate removal efficiency and excessive sparking which will have the opposite effect. Larger ESPs are sectionalized (see *Figure 4-2*) such that higher voltages can be used in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages are then used in the last, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. This has the added advantage that particles re-entrained in the flue gas stream by rapping (striking the electrode to dislodge the dust) may be collected in the downstream sections of the ESP.

Precipitator size is a major variable affecting overall performance or collection efficiency. Size determines residence time (the time a particle spends in the precipitator). Precipitator size also is typically defined in terms of the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher SCA leads to higher removal efficiencies. Collection areas can range from as low as 200 to as high as 800 ft^2/1000

acfm. In order to achieve collection efficiencies of 99.5 percent, SCA of 350-400 ft^2/1000 acfm is typically used. The overall (mass) collection efficiencies of ESPs can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies can achieve high efficiencies across a range of particle sizes so that good control of PM_{10} and $PM_{2.5}$ is possible with well designed and operated electrostatic precipitators.

Unlike dry ESPs, which use rapping to remove particulates from the collecting electrodes, wet ESPs use a water spray to remove the particulates. By continually wetting the collection surface, the collecting walls never build up a layer of particulate matter. This means that there is little or no deterioration of the electrical field due to resistivity, and power levels within a wet ESP can therefore be higher than in a dry ESP. The ability to inject greater electrical power within the wet ESP and elimination of secondary re-entrainment are the main reasons a wet ESP can collect sub-micron particulate more efficiently.

Overall, ESPs have historically been the collection device of choice for many applications in the ICI boiler and EGU boiler sectors. High removal efficiencies are possible and the units are rugged and relatively insensitive to operating upsets. Wet ESPs offer performance characteristics for capturing $PM_{2.5}$ similar to fabric filters and are well suited for applications such as oil firing, for which fabric filters are less attractive, because the sticky ash particles produced from oil combustion can blind the bags.

4.3.3 Venturi Scrubbers

Venturi scrubbers for PM control operate on the principle of rapid mixing and impingement of PM with liquid droplets and subsequent removal with the liquid waste. For particulate controls, the venturi scrubber is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressure drops are required. High-energy scrubbers operate at pressure losses of 50 to 70 inches of water. Higher pressure drop translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis. However, venturi scrubbers are seldom used as the primary PM collection device because of excessive pressure drop and associated energy penalties. *Figure 4-4* depicts a venturi scrubber.

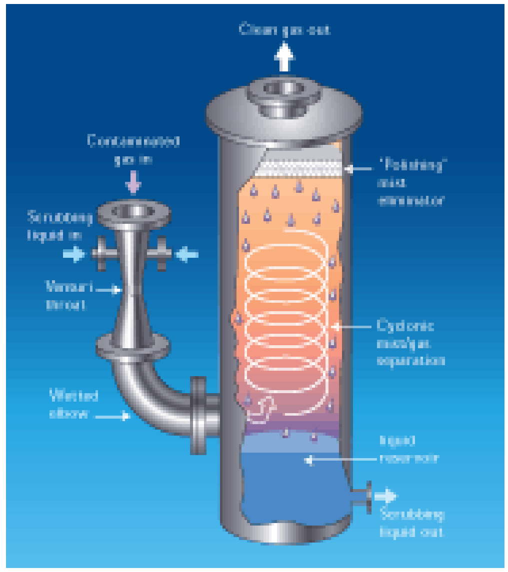

Figure 4-4. Venturi scrubber [Croll Reynolds]

4.3.4 Cyclones

Cyclones are devices that separate particulates from the gas stream through inertial forces. As ash-laden gas enters the cyclone near the top, a high-velocity vortex is created inside the device. Heavy particles move outward due to centrifugal force and begin accumulating on the wall of the cyclone. Gravity continuously forces these particles to move downward where they collect in the lower, hopper region of the cyclone. The collected particles eventually discharge through an opening in the bottom of the hopper into a system that transports the particles to a storage area. Smaller and lighter particles that remain suspended in the flue gas move toward the center of the vortex before being discharged through the clean-gas outlet located near the top of the cyclone (see *Figure 4-5*).

Cyclones are comparatively simple devices in design and construction, with no moving parts. Cyclones can operate over a wide range of temperatures, which makes them attractive for smaller ICI boilers that do not have economizers and/or air preheaters (and thus higher stack temperatures than in EGU boilers). Pressure drops across cyclones are typically in the range of 2 to 8 inches of water for a single cyclone. Cyclones can be arranged in arrays (multi-cyclones) and have overall mass removal efficiencies of 70 to 90 percent with the corresponding increase in pressure drop. However, cyclone collection efficiencies are very sensitive to particle size, and control efficiency for fine particulate ($PM_{2.5}$) is poor [Licht, 1988].

Cyclones are most effective at high boiler loads, where flue gas flow rates are highest. From an operational perspective, cyclones have no moving parts, are not sensitive to fuel quality or gas temperature, and require only regular cleaning to avoid plugging. These characteristics have made them good options in the past, particularly in the absence of regulatory $PM_{2.5}$ requirements.

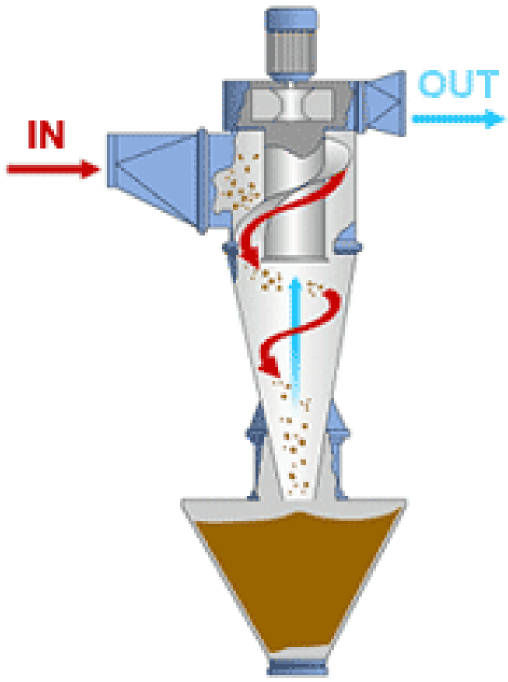

Figure 4-5. Schematic of a cyclone collector [www.dustcollectorexperts.com/cyclone]

Due to the limited potential for $PM_{2.5}$ capture, use of cyclones in new combustion applications is primarily limited to fluidized-bed boilers where they are used to re-circulate the bed material – and not as primary PM control devices.

4.3.5 Core Separator

The core separator is a mechanical device that operates based on aerodynamic separation (like cyclones), but also utilizes a "core separator." The separator portion of the device consists of multiple cylindrical tubes with one inlet and two outlets. One outlet allows for a clean gas stream to exit, while the other outlet is used for recirculating the concentrated stream. This recirculation stream then passes through the cyclone unit (see *Figure 4-6* [Resource Systems Group, 2001]), where it is further cleaned and returned to the separator. This sequential process enhances its overall control efficiency as compared to single or multiple cyclones.

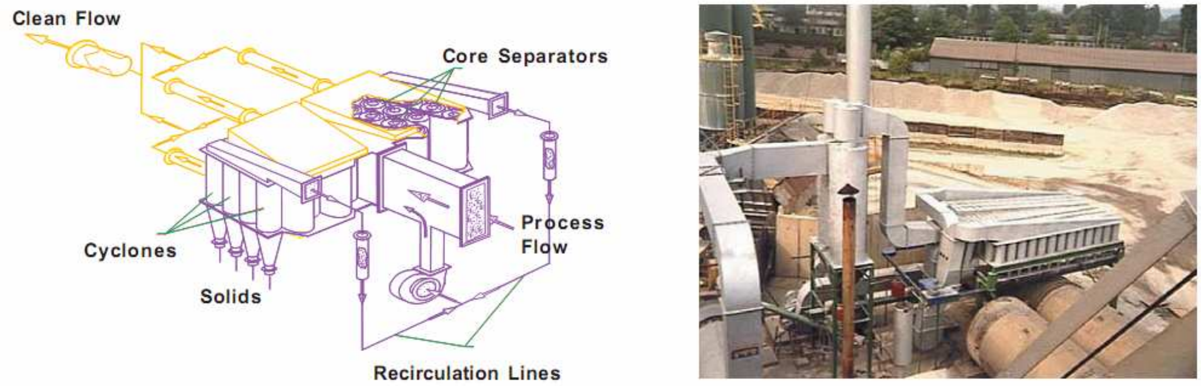

Figure 4-6. Schematic (left) and actual (right) core separator system [EPA, 2003]

The core separator capability for PM removal falls between that of an ESP and a cyclone. Several systems are currently installed on coal- and wood-fired boilers. The core separator unit is capable of overall PM reductions of up to the 90 percent range. Its collection efficiency, however, diminishes to about 50 percent for $PM_{2.5}$. *Table 4-2* displays inlet and outlet PM concentrations and removal efficiency of a core separator at two different plants. *Table 4-3* presents estimated costs for the core separator for two different sizes and gas flow conditions.

Table 4-2. Core separator collection efficiency [USEPA, 2008; Resource Systems Group, 2001]

Core Separator Inlet Loading (lb/million Btu)	Core Separator Outlet Loading (lb/million Btu)	Removal Efficiency	Boiler Type
0.17	0.07	59%	Wood Fired
0.846	0.214	75%	Stoker – Coal

Table 4-3. Core separator cost analysis [B. H. Eason to P. Amar, 2008]

Boiler Size	MMBtu/hr	8	10
	Estimated gas temperature (°F)	500	500
	Estimated gas flow rate (acfm)	4979	5996
Core Separator Size and Estimated Price (uninstalled)	Gas Flow per 12” module	660	660
	Number of 12” Modules	7	9
	Estimated price	$110,000	$130,000
	Gas Flow per 24” Module	2640	2640
	Number of 24” Modules	1	2
	Estimated Price	$55,000	$83,000

4.4 Applicability of PM Control Technologies to ICI Boilers

The PM control technologies described in this section are widely available and are used in both ICI and EGU applications. Because all these PM controls are based on the collection of particulates from the flue gas, they are applicable to a variety of boiler types and ash-containing

fuels, including coal, oil, wood, petroleum coke, and other waste fuels. Determining the most attractive option for individual applications is a case-by-case decision that needs to account for technical, economic, and regulatory considerations. One exception, as mentioned, is that fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash.

4.5 Efficiency Impacts

PM control technologies do result in some parasitic energy loss as can be deduced from the brief descriptions of technologies above (see *Table 4-1*). The inherent energy losses associated with each technology are given below and summarized in *Table 4-4*.

- For Fabric Filters
  - compressor (bag cleaning)
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For ESPs
  - transformer-rectifier (TR) power
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For Venturi Scrubber and Cyclone
  - flue gas pressure loss

Table 4-4. Summary of energy impacts for control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)	Comments
Fabric Filter	Coal, Wood	99+	1 – 2	Pressure loss / compressor / ash handling
Dry ESP	Coal, Oil, Wood	99	0.5 – 1.5	Pressure loss / TR power / ash handling
Wet ESP	Coal, Oil, Wood	99+	3 - 6	Pressure loss / TR power / ash handling
Venturi Scrubber	Coal, Oil, Wood	70-90 (Not efficient for $PM_{2.5}$)	5 - 11	Pressure loss
Cyclone	Coal, Wood	70-90 (Not efficient for $PM_{2.5}$)	0.5 – 1.5	Pressure loss

4.6 PM Control Costs

The following tables summarize published PM control costs for ICI boilers reported in the literature [US EPA, 2003a; US EPA, 2003b; US EPA, 2003c; US EPA, 2003d; US EPA, 2003e; US EPA, 2003f; MACTEC, 2005]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness

in dollars per ton of PM removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some of the operating costs, but these items do not always increase with the rate of inflation for chemical plant equipment. Thus, cost effectiveness values (or operating costs) from years before 2005 have not been reported.

Table 4-5 summarizes the published PM control costs for several different PM control technologies. In the EPA references, the capital costs were given in terms of dollars/scfm (2002 dollars). These costs were converted to dollars per MMBtu/hr using the flow rates given in Chapter Five and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values.

The MACTEC capital costs [MACTEC, 2005] span a large range, because high and low estimates for capital equipment were used in the calculation. The EPA capital costs are much higher for the wire-pipe ESP (also known as a tubular ESP) than the wire-plate ESP. Note that a size was not given in the EPA cost estimate, so a range is shown. The capital cost comparison is similar for wet ESPs although the capital costs themselves (in dollars/MMBtu/hr) are higher for wet ESPs as compared to dry ESPs.

For fabric filters, pulse-jet and reverse-air fabric filters were considered. These types of equipment have similar collection efficiencies, but the capital costs and effectiveness of pulse-jet fabric filters are lower than that of reverse-air fabric filters.

Table 4-5. PM control costs applied to ICI boilers

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu /hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Dry ESP	90%	Coal	250	$12,365-$160,754	2005	$171-$1,300	7
Dry ESP	99%	Coal	250	$12,365-$160,754	2005	$156-$1,172	7
Dry ESP	90%	Oil	250	$6,713-$87,275	2005	$2,584-$21,009	7
Dry ESP	99%	Oil	250	$6,713-$87,275	2005	$2,328-$18,912	7
Dry ESP (Wire-Pipe)		Coal	--	$6,571-$41,070	2002		1
Dry ESP (Wire-Plate)	90%-99%	Coal	--	$3,286-$10,843	2002		2
Dry ESP (Wire-Pipe)		Resid.Oil	--	$5,198-$32,486	2002		1
Dry ESP (Wire-Plate)	90%-99%	Resid.Oil	--	$2,599-$8,576	2002		2
Dry ESP (Wire-Pipe)		Dist.Oil	--	$5,117-$31,983	2002		1
Dry ESP (Wire-Plate)	90%-99%	Dist.Oil	--	$2,559-$8,443	2002		2
Dry ESP (Wire-Pipe)		Wood	--	$7,560-$47,249	2002		1
Dry ESP (Wire-Plate)	90%-99%	Wood	--	$3,780-$12,474	2002		2
ESP	99.50%	Wood	Small	--	2005	$594	8
ESP	99.50%	Wood	Medium	--	2005	$203-$292	8
ESP	99.50%	Wood	Large	--	2005	$114-130	8
Fabric Filter	90%	Coal	250	$7,453-$93,158	2005	$444-$1,006	7
Fabric Filter	99%	Coal	250	$7,453-$93,158	2005	$423-$957	7
Pulse-Jet Fabric Filter	95%-99.9%	Coal	--	$1,971-$8,543	2002		5
Reverse-Air FF	95%-99.9%	Coal	--	$3,286-$28,585	2002		6
Fabric Filter	90%	Oil	250	$4,046-$50,577	2005	$7,277-$16,464	7
Fabric Filter	99%	Oil	250	$4,046-$50,577	2005	$6,915-$15,643	7
Pulse-Jet Fabric Filter	95%-99.9%	Resid.Oil	--	$1,559-$6,757	2002		5
Reverse-Air FF	95%-99.9%	Resid.Oil	--	$2,559-$22,260	2002		6
Pulse-Jet Fabric Filter	95%-99.9%	Dist.Oil	--	$1,535-$6,652	2002		5
Reverse-Air FF	95%-99.9%	Dist.Oil	--	$2,599-$22,610	2002		6
Fabric Filter	99.50%	Wood	Small	--	2005	$958	8
Fabric Filter	99.50%	Wood	Medium	--	2005	$147-249	8
Fabric Filter	99.50%	Wood	Large	--	2005	$91-$107	8
Pulse-Jet Fabric Filter	95%-99.9%	Wood	--	$2,268-$9,829	2002		5
Reverse-Air FF	95%-99.9%	Wood	--	$3,780-$32,886	2002		6

Table 4-5 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet ESP	90%	Coal	250	$25,968-$252,260	2005	$906-$2,627	7
Wet ESP	99.9%	Coal	250	$25,968-$252,260	2005	$815-2,365	7
Wet ESP (Wire-Pipe)	90%-99.9%	Coal	--	$13,142-$65,712	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Coal	--	$6,571-$13,142	2002		4
Wet ESP	90%	Oil	250	$14,098-$136,955	2005	$14,938-$43,036	7
Wet ESP	99.9%	Oil	250	$14,098-$136,955	2005	$13,446-$38,736	7
Wet ESP (Wire-Pipe)	90%-99.9%	Resid.Oil	--	$10,395-$51,977	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Resid.Oil	--	$5,198-$10,395	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Dist.Oil	--	$10,235-$51,172	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Dist.Oil	--	$5,117-$10,234	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Wood	--	$15,120-$75,599	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Wood	--	$7,560-$15,120	2002		4

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5 APPLICATION OF A COST MODEL TO ICI BOILERS

When evaluating the applicability of pollution control equipment to a specific ICI boiler, cost and performance capability need to be considered. A number of cost estimation models have been created for estimation of capital and operating costs of retrofit technology for air pollutants. However, most of the cost models have been developed for and applied to EGUs burning coal. Much less work has been carried out on cost estimation models for ICI boilers. In this Chapter, a cost modeling approach currently used for estimating control costs for coal-burning EGUs is modified and then investigated for its applicability to ICI boilers burning coal as well as other fuels. The purpose of this Chapter is to present this modified cost model (CUECost-ICI) and resulting cost calculations. The strengths and weaknesses of this approach are also discussed. However, the purpose of this effort is not to carry out an exhaustive calculation of costs, but to generate a set of reasonable cost estimates for ICI boilers burning different fuels and compare them with published cost information.

5.1 Cost Model Inputs and Assumptions

The Coal Utility Environmental Cost (CUECost) model was developed by Raytheon Engineers for EPA; version 3, and is available on EPA's website at http://www.epa.gov/ttn/catc/products.html. The model calculates capital and operating costs for certain predefined air pollution control devices for control of NOx, SO_2, and PM as applied to coal-fired power plants. The CUECost model produces approximate cost estimates (±30 percent accuracy) of the installed capital and annualized operating costs. The CUECost model was originally designed for and is intended for use on coal-fired boilers greater in size than 100 MW (about 1,000 MMBtu/hr heat input).

Table 5-1 gives the general plant inputs that are needed to set up the model; more inputs are needed for specific air pollution control devices (see Appendix B).

Table 5-1. CUECost general plant inputs

Input Parameter	***Comment***
Location - State	
MW Equivalent of Flue Gas to Control System	*This was designed for EGUs, but can be scaled to generate the appropriate gas flow for ICIs*
Net Plant Heat Rate	*Function of the efficiency of the plant*
Plant Capacity Factor	*Use averages from EEA study, parametric variations*
Percent Excess Air in Boiler	*Assume 3% O_2 for NG and oil, 7% O_2 for coal, wood*
Air Heater In-leakage	*Determines the flow rate for downstream devices such as scrubbers and particulate control devices*
Air Heater Outlet Gas Temperature	
Inlet Air Temperature	
Ambient Absolute Pressure	
Pressure After Air Heater	
Moisture in Air	
Ash Split:	*Depends on firing system*
Fly Ash	
Bottom Ash	
Seismic Zone	
Retrofit Factor	*Moderate effect on total capital requirement (TCR)*
(1.0 = new, 1.3 = medium, 1.6 = difficult)	
Select Fuel	*User can define "coal" with respect to HHV, %S, %ash*

The EPA version of CUECost contains the following modules for specific air pollution control devices:

- Limestone forced-oxidation, wet FGD scrubber
- Lime spray dryer
- FF
- ESP
- SCR
- SNCR
- LNB
- Natural Gas Reburn

CUECost bases the costs of equipment and operation on the generating capacity (in MW of electricity generated) of a given boiler. Industrial boilers are usually rated by the heat input (in MMBtu/hr); the boiler heat rate is used to convert from heat input to the equivalent size in MW. In order to use CUECost in its present form for ICI boilers, an equivalent size in MW needs to be estimated, although this could be modified in a dedicated ICI boiler version of CUECost (which was not developed in this effort).

Industrial boilers are operated differently from utility boilers, and the inputs for CUECost-ICI must be adjusted accordingly, including:

- Heat rate
- Excess air level

- Flue gas temperatures
- Capacity factor

The default values in the current version of CUECost for EGUs generally do not describe ICI boilers well. Fuel compositions vary widely for ICI boilers, while the EGU version of CUECost includes coal as the only fuel option (with different compositions). However, the user can define other fuels, as described below.

An important factor in determining total installed capital cost is the choice of appropriate retrofit factor, which expresses the difficulty of installing a control technology in an existing plant. In CUECost a retrofit factor of 1.0 denotes a new plant (corresponding to the lowest capital cost), and retrofit factors of 1.3 and 1.6 denote medium and difficult retrofits, respectively. Emmel [2006] noted that this range of retrofit factors significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs less than 100 MW. Emmel also noted that on average a retrofit factor of 1.45 was more reasonable and that the factor should be even higher when CUECost is applied to ICI boilers.

The technology options in CUECost are also fixed, and the user cannot create a new technology option without supplying formulae for calculating the capital equipment cost. The technology options for SO_2 control in CUECost, in particular, have been noted to be more appropriate for larger utility boilers than for ICI boilers. Wet FGD and spray dryer technology – the SO_2 scrubbing options in CUECost – are based on lime or limestone reagents and have high capital and operating costs compared to alkaline scrubbers or duct injection. The latter scrubbing options might be more attractive for ICI boilers, but would have to be added to the current version of CUECost.

Finally, Emmel [2006] notes that most ICI boiler sites will have higher contingency, general facility, engineering, and maintenance costs (on a percentage of capital cost basis) than those identified for EGUs in CUECost in order to take into account necessary upgrades or demolition of existing facilities that are less likely to be needed at sites.

In this effort, the CUECost model was adapted for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. Capital and operating costs in the model were based on correlations derived from coal-fired power plant experience since no reliable field data were available for the ICI boilers. It is not clear how robust the correlations for capital equipment are for small (≤ 25 MW equivalent) boilers.

The CUECost model is based on the electrical generating capacity. A combustion calculation was used to relate heat input rate to equivalent MW for five different fuels.

Table 5-2 gives the properties of these fuels. Boiler efficiency was specified, and heat rate was calculated from boiler efficiency. The uncontrolled or baseline emissions were based on fuel composition (in the case of SO_2 and PM) or on industry operating experience (in the case of NOx).

Table 5-3 shows the results (in terms of calculated flue gas flow rates) of the combustion calculations for a fixed heat input rate of 250 MMBtu/hr or 100 MMBtu/hr. Flue gas flow rate is an important parameter or input to the cost model, because the size of capital equipment is often related to the flue gas flow rate.

Table 5-2. Fuel characteristics and assumptions for CUECost calculation of heat rate and flue gas flow rates

	Bituminous	Wood	No.2 Oil	No.6 Oil	Gas
C, wt%	76.2	27.6	86.4	85.8	75
S, wt%	2.5	0.04	0.6	2.5	0
H, wt%	4.6	3.3	12.7	10.6	25
Moisture, wt%	1.4	45	0.02	0.02	0
N, wt%	1.4	0.3	0.1	0.5	0
O, wt%	7	22.86	0.1	0.5	0
Ash, wt%	6.9	0.9	0.08	0.08	0
Fuel heating value, BTU/lb	13,630	4,633	19,563	18,273	20,800
Unburned carbon, wt% in ash	5	1	75	75	0
Boiler efficiency*	34%	30%	39%	39%	45%
Stack O_2, vol% dry	7%	7%	3%	3%	3%
Boiler heat rate, Btu/kWh	10,000	11,370	8,750	8,750	7,600
Uncontrolled or Baseline emissions NOx, lb NO_2/MMBtu	0.60	0.26	0.20	0.40	0.40
SO_2, lb/MMBtu	3.67	0.17	0.61	2.74	0.00
PM, lb/MMBtu	5.06	1.94	0.04	0.04	0.00

*****Fuel to MW

Table 5-3. Equivalent heat input rate and flue gas flow rates for 250 and 100 MMBtu/hr heat input rates

	MW	MMBtu/hr	Flue gas, scfm
Bituminous coal (34% efficiency, 7% O_2)	25.0	250	65,305
Wood (30% efficiency, 7% O_2)	22.0	250	81,184
No.2 oil (39% efficiency, 3% O_2)	28.6	250	50,622
No.6 oil (39% efficiency, 3% O_2)	28.6	250	51,117
Natural gas (45% efficiency, 3% O_2)	32.9	250	59,336
Bituminous coal (34% efficiency, 7% O_2)	10.0	100	26,122
Wood (30% efficiency, 7% O_2)	8.8	100	32,474
No.2 oil (39% efficiency, 3% O_2)	11.4	100	20,178
No.6 oil (39% efficiency, 3% O_2)	11.4	100	20,375
Natural gas (45% efficiency, 3% O_2)	13.2	100	23,806

5.2 Comparison of the Cost Model Results with Literature

A comparison was made of the CUECost-ICI model with other published information for a selection of fuels and air pollution control devices applied to ICI boilers. Where possible, the inputs for the model were set to be the same as information cited in the literature.

Using the appropriate fuel composition and boiler heat rates, the modified ICI version of the original CUECost (CUECost-ICI) model was run for a number of ICI boiler cases. *Table 5-4*, *Table 5-5*, and *Table 5-6* show the installed capital costs, first-year annual operating costs, and cost per ton of pollutant removed for NOx, SO_2, and PM, respectively. Capital and operating costs were calculated on 2006 dollars basis in the CUECost-ICI model. A complete

list of inputs to CUECost-ICI is included in Appendix B. For the NOx and SO_2 control technologies, percentage reduction of the pollutant was used as an input, so that the CUECost-ICI results could be easily compared to published literature results. For PM controls, a specific emission limit (in lb/MMBtu) was used as an input and the percentage PM reduction was calculated from the fuel ash content.

Table 5-4. Capital and operating costs for NOx control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost/ton
250	80.0%	Coal	SCR	Ammonia	$4.394	$1.253	$4,763
100	80.0%	Coal	SCR	Ammonia	$2.585	$0.702	$6,668
250	80.0%	No.6 Oil	SCR	Ammonia	$2.923	$0.790	$3,972
100	80.0%	No.6 Oil	SCR	Ammonia	$1.760	$0.460	$5,805
250	80.0%	Nat.Gas	SCR	Ammonia	$3.005	$0.811	$4,673
100	80.0%	Nat.Gas	SCR	Ammonia	$1.805	$0.472	$6,777
250	50.0%	Coal	SNCR	Ammonia	$1.142	$0.398	$2,422
100	50.0%	Coal	SNCR	Ammonia	$0.969	$0.317	$4,817
250	50.0%	No.6 Oil	SNCR	Ammonia	$0.724	$0.338	$2,722
100	50.0%	No.6 Oil	SNCR	Ammonia	$0.407	$0.196	$3,961
250	50.0%	Nat.Gas	SNCR	Ammonia	$0.785	$0.362	$3,335
100	50.0%	Nat.Gas	SNCR	Ammonia	$0.443	$0.209	$4,798
250	40.0%	Coal	LNB	--	$1.227	$0.301	$2,290
100	40.0%	Coal	LNB	--	$0.677	$0.166	$3,155
250	40.0%	No.6 Oil	LNB	--	$1.339	$0.329	$3,305
100	40.0%	No.6 Oil	LNB	--	$0.737	$0.181	$4,559
250	40.0%	Nat.Gas	LNB	--	$1.467	$0.360	$4,151
100	40.0%	Nat.Gas	LNB	--	$0.810	$0.199	$5,715

Table 5-5. Capital and operating costs for SO_2 control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	95%	Coal	wFGD	Limestone	$38.096	$11.137	$4,427
100	95%	Coal	wFGD	Limestone	$33.680	$9.608	$9,547
250	95%	No.6 Oil	wFGD	Limestone	$36.642	$10.733	$5,713
100	95%	No.6 Oil	wFGD	Limestone	$32.805	$9.368	$12,510
250	90%	Coal	SD	Lime	$29.598	$8.806	$3,694
100	90%	Coal	SD	Lime	$26.263	$7.540	$7,909
250	90%	No.6 Oil	SD	Lime	$28.463	$8.371	$4,704
100	90%	No.6 Oil	SD	Lime	$25.723	$7.344	$10,352

Table 5-6. Capital and operating costs for PM control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	PM Emission, lb/MMBtu	Installed Capital Cost, $M	Capital cost, $/scfm	Capital cost, $/acfm	Annua l Cost, $M	Cost Effective ness (dollars per ton)
250	99.3%	Coal	ESP	0.03	$4.05	$62.00	$43.00	$1.11	$342
100	99.3%	Coal	ESP	0.03	$2.31	$88.50	$61.50	$0.63	$485
250	99.3%	Coal	FF	0.03	$4.77	$73.00	$50.70	$1.32	$406
100	99.3%	Coal	FF	0.03	$2.88	$110.20	$76.60	$0.78	$592
250	95.8%	No.6 Oil	ESP	0.01	$3.40	$66.60	$46.30	$0.93	$5,689
100	95.8%	No.6 Oil	ESP	0.01	$2.02	$99.00	$68.80	$0.55	$8,410
250	95.8%	No.6 Oil	FF	0.01	$4.09	$80.00	$55.60	$1.14	$6,940
100	95.8%	No.6 Oil	FF	0.01	$2.50	$122.80	$85.30	$0.68	$10,354

For comparison, the American Forest & Paper Association (AF&PA) calculated SNCR control costs in 2006 for wood-fired boilers ranging in size from 88 to 265 MMBtu/hr [Hunt, 2006]. *Table 5-7* below compares the AF&PA costs with the CUECost-ICI costs for wood-fired boilers. The installed capital cost values agree well between CUECost-ICI and the AF&PA estimates, although the CUECost-ICI values for cost effectiveness (dollars per ton of NOx removed) are 20 to 25 percent lower than the AF&PA estimates.

Table 5-7. Capital and operating costs for SNCR on wood-fired boilers, comparison of cost calculations from AF&PA and CUECost

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost, $/ton
AF&PA							
88.5	70.0%	Wood	SNCR	Urea	$0.924	$0.250	$11,283
176.9	70.0%	Wood	SNCR	Urea	$1.400	$0.384	$8,574
285.4	70.0%	Wood	SNCR	Urea	$1.786	$0.502	$7,480
CUECost							
88.5	70.0%	Wood	SNCR	Urea	$0.923	$0.289	$9,239
176.9	70.0%	Wood	SNCR	Urea	$1.025	$0.324	$5,174
285.4	70.0%	Wood	SNCR	Urea	$1.130	$0.361	$5,011

Finally, the CUECost-ICI model results for capital cost were compared with some of the values reported in the literature [US EPA, 1996; NESCAUM, 2000; US EPA, 2003a; US EPA, 2003b; Whiteman, 2006], where available. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using Chemical Engineering Plant Cost Index values.

The NOx capital costs computed with CUECost-ICI were largely consistent with the literature values. (Chapter Two contains a detailed discussion of the literature values for NOx control costs.)

Figure 5-1 compares capital costs for SCR for boilers burning coal, residual (No. 6) oil, and natural gas. The SCR costs appear to be consistent with the literature values. The literature value for SCR as reported by the Ozone Transport Assessment Group (OTAG) [US EPA, 1996] did not describe its basis in any detail, so it is difficult to determine if the OTAG cost estimates assumed a significantly different space velocity or different equipment than assumed in the CUECost-ICI model.

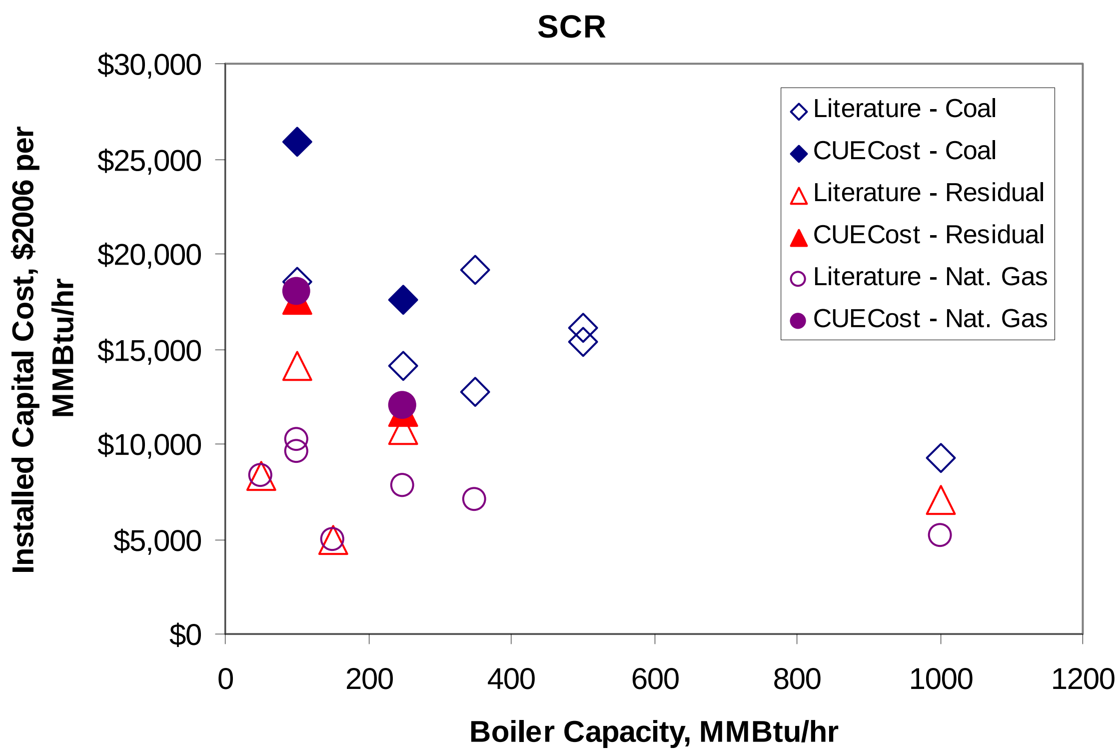

Figure 5-1. Comparison of CUECost-ICI model and reported literature values for capital cost of SCR for NOx control

The capital costs for SNCR (*Figure 5-2*) calculated from the CUECost-ICI model are in good agreement with literature values, particularly the sensitivity of capital cost to boiler capacity, which was also noted by ICAC [Whiteman, 2006].

The capital costs for LNB (*Figure 5-3*) calculated from the CUECost-ICI model for coal-fired boilers were consistent with the literature values, although the capital costs for residual oil-fired boilers were higher in the CUECost-ICI model than the literature values. Again, no details were provided in the literature references.

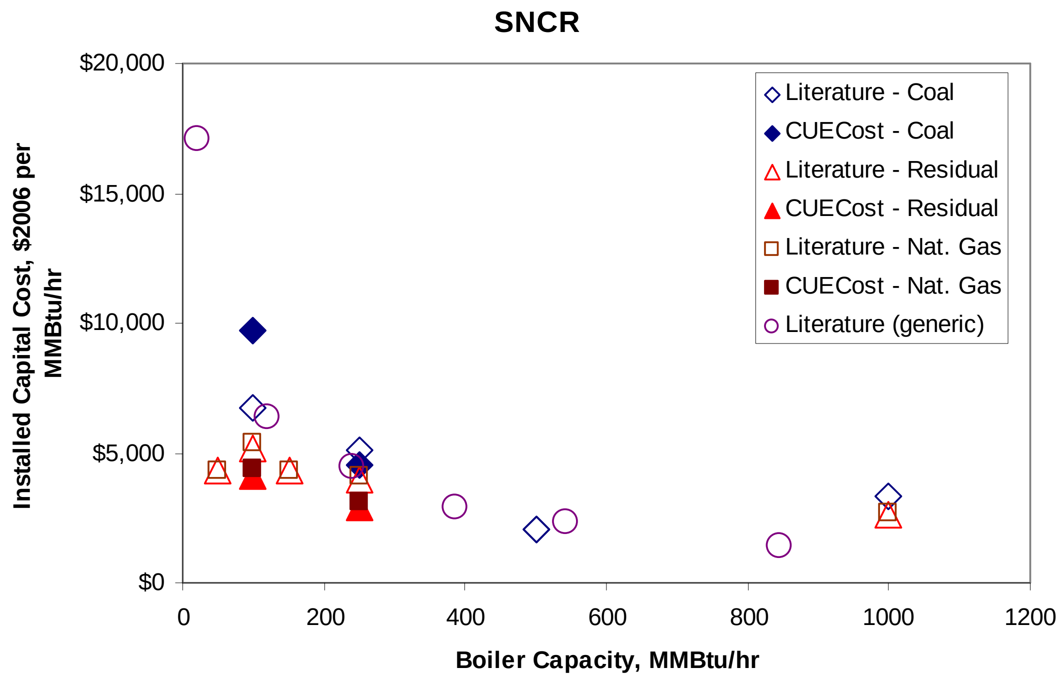

Figure 5-2. Comparison of CUECost-ICI model and reported literature values for capital cost of SNCR for NOx control

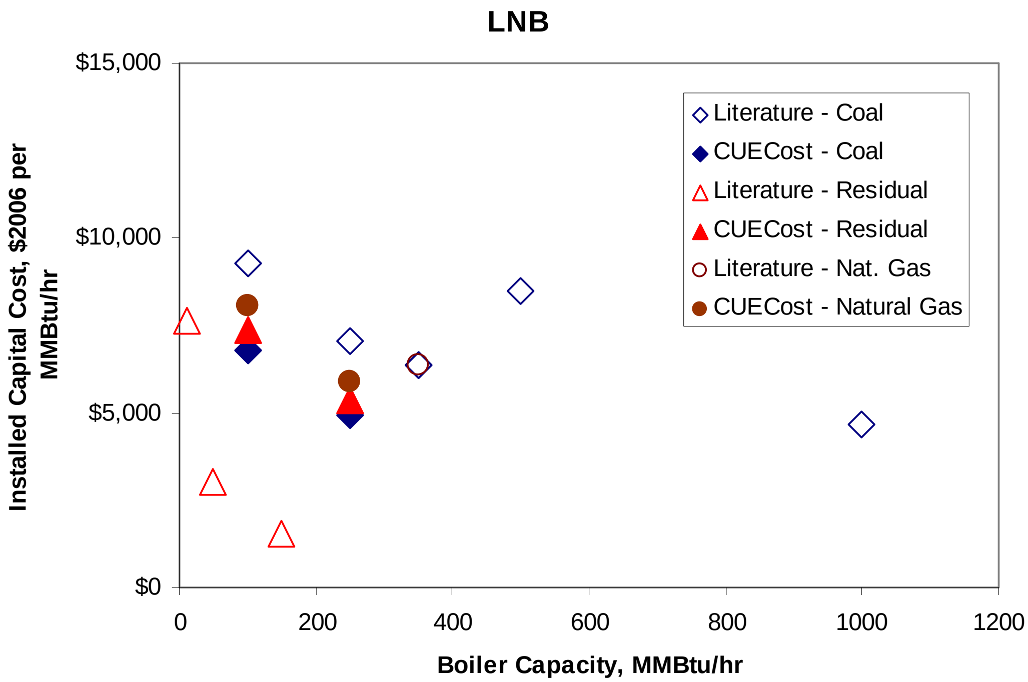

Figure 5-3. Comparison of CUECost-ICI model and reported literature values for capital cost of LNB for NOx control

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs. The SO_2 capital costs computed with CUECost-ICI for spray dryers (SDs) were in the range of the literature values at boiler size of 250 MMBtu/hr (*Figure 5-4*). No literature data were available for residual oil-fired boilers and spray dryers. However, the capital costs calculated by CUECost –ICI for wet FGDs (*Figure 5-5*) were high when compared to the literature values.

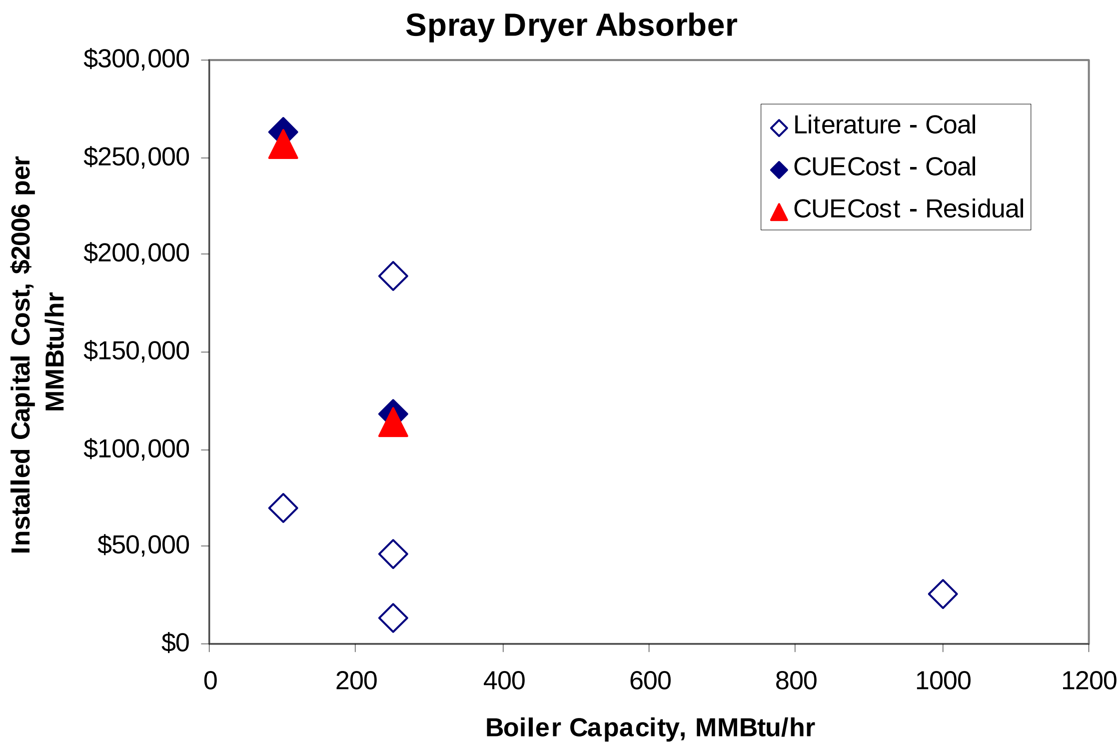

Figure 5-4. Comparison of CUECost-ICI model and reported literature values for capital cost of Spray Dryer for SO_2 control

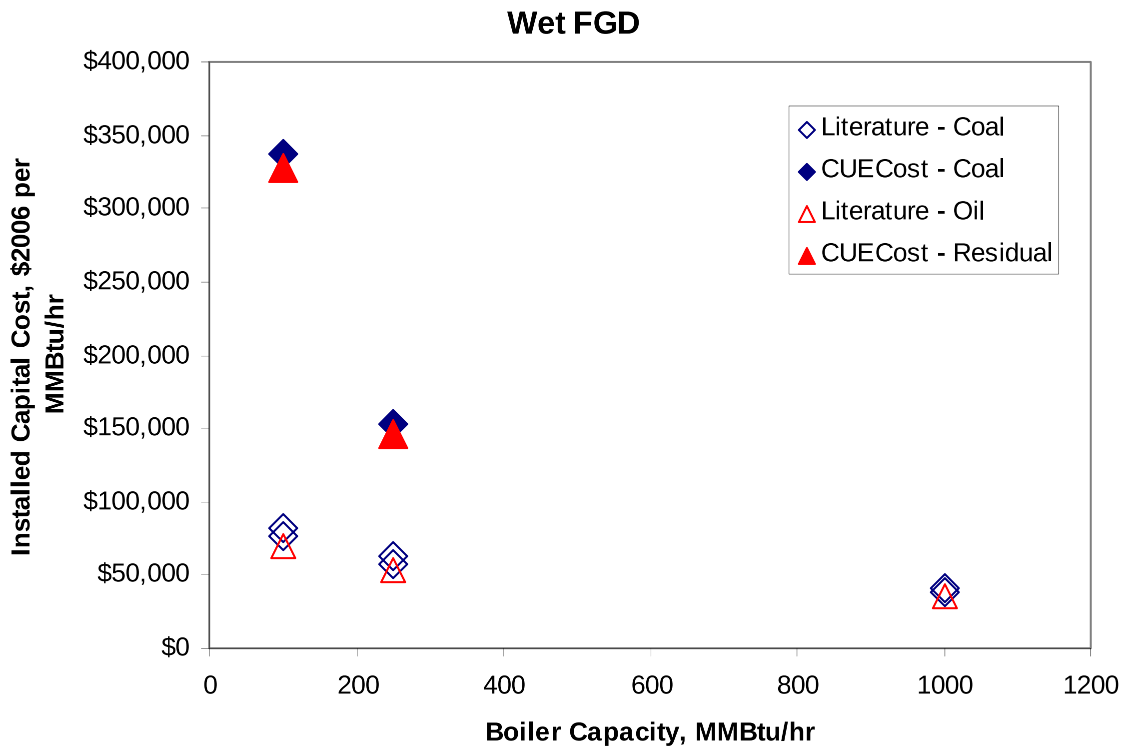

Figure 5-5. Comparison of CUECost-ICI model and reported literature values for capital cost of wet FGD for SO_2 control

Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to ICI boilers [US EPA, 2003a; US EPA, 2003b]. In these references, the capital costs were given in terms of dollars/scfm (2002$). These costs were converted to dollars per MMBtu/hr using the flow rates in *Table 5-3* and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values. Chapter Four contains a detailed discussion of the literature values for PM control costs.

The dry ESP control costs computed with CUECost-ICI were consistent with the literature values, although the CUECost-ICI predicted slightly higher values than reported by EPA for dry, wire-plate ESPs [US EPA, 2003a]. Note that a size was not given in the EPA cost-estimate. The FF costs computed with CUECost-ICI were higher than the literature values for pulse-jet fabric filters [US EPA 2003b].

5.3 Summary

An existing EPA model for estimating costs of selected control technology for NOx, SO_2, and PM for coal-fired EGU boilers greater than 1,000 MMBtu/hr was adapted for ICI boilers. Inputs were modified to allow a wider variety of fuels and to express boiler capacity in MMBtu/hr instead of MW. Modification of the correlations used for the coal-fired EGU model to calculate capital and operating costs for ICI boilers was outside the scope of this work. The new model, CUECost-ICI provided good agreement with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers. The resulting model provided a quick and flexible means to estimate capital and operating costs of

specific control technologies as applied to ICI boilers. Further detailed and extensive work will be needed to validate and refine the model's calculation framework for ICI boilers, and to add other APCD technologies to the model.

5.4 Chapter 5 References

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US EPA. *Air Pollution Control Technology Fact Sheet: Fabric Filter - Pulse-Jet Cleaned Type*; EPA-452/F-03-025, July 15, 2003b. http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf.

Whiteman, C. ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.

6 SUMMARY

ICI boilers are a significant source of NO_x, SO_2, and PM emissions, and are relatively uncontrolled, compared to EGUs. More than half of the surveyed ICI boilers in the Northeast have no controls, approximately one-third have PM controls, very few units have NOx controls, and no units have SO_2 controls.

There are a range of technology options for cost-effectively reducing emissions of NOx, SO_2, and PM emissions from ICI boilers in the U.S. Operating costs may differ for ICI boilers than utility boilers, primarily because of their size and location. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs as a percentage of total capital cost than do utility boilers. While ICI boilers often have cost constraints due to their sizes and diversity of plant layout and settings, these factors also provide opportunities for low-cost applications. It is critical to conduct site-specific suitability analyses to assess performance potential or retrofit feasibility, and match the appropriate emission control technology for specific applications given boiler size, fuel type/quality, duty-cycle, and design characteristics.

This study adapted the CUECost model -- initially developed by EPA to estimate costs of selected control technology for NOx, SO_2, and PM for large coal-fired EGU boilers -- to assess ICI boiler control costs. The modeling results were consistent with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers.

6.1 NOx Controls

Most of the commercially available NOx control technologies used extensively in EGUs may also apply to ICI boilers. Some technologies have potential to capture mercury from the flue gas. Employing a combination of technologies can be more effective in reducing emissions than a stand-alone technology. While most of these technologies can be used together, some combinations may be more cost-effective. This should be assessed on a site- and strategy-specific basis. Options include:

- *Boiler Tuning or Optimization*, which can yield reductions of five to 15 percent or more;
- *Low-NOx Burner (LNB) and Overfire Air (OFA)*, which can be used separately or as a system, and can reduce NOx emissions by 40 to 60 percent. LNBs are applicable to most ICI boiler types, and are being increasingly used at ICI boilers less than 10 MMBtu/hr. These technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility.
- *Ultra Low-NOx Burners (ULNB)*, which can achieve NOx emission levels on the order of single digits in ppm.
- *Reburn*, which has been used only in large EGU applications, but is an option for larger watertube-type boilers, including stokers. It requires appropriate technical and economic analyses to determine suitability. Reburn may yield 35 to 60 percent reductions in NOx emissions.
- *Selective Catalytic Reduction (SCR)*, which can achieve reductions higher than 90 percent.

- *Selective Non-Catalytic Reduction* (*SNCR)*, which can achieve between a 30 to 60 percent reduction in NOx.
- *Regenerative Selective Catalytic Reduction (RSCR^{TM})*, which is able to reduce NOx by 60 to 75 percent and CO by about 50 percent. These systems allow efficient use of an SCR downstream of a particulate control device, where the flue gas typically has a lower temperature than what is required for a conventional SCR. Such conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the exception of reburn. SNCR and SCR impose some degree of energy demand on the host boiler, including pressure, compressor, vaporization, and steam losses.

Most estimates for ICI boilers indicate capital costs in the range of $1,000 to $6,000 per MMBtu/hr and $1,000 to $7,000 per ton of NOx removed. LNBs and SNCR costs range from $1,000 to $3,000 per ton. For SCR, costs are between $2,000 and $14,000 per ton. SCR and SNCR costs are driven primarily by the consumption of the chemical reagent.

6.2 SO_2 Controls

ICI boilers firing coal are good candidates for employing SO_2 control technologies. Options include:

- *Flue Gas Desulfurization (FGD) or Scrubbers.* These technologies are commercially available, and have been used extensively on EGUs since the 1970s. *Wet scrubbers* (Wet FGD) are the predominant SO_2 control technology currently in use for EGUs, and are typically associated with high-sulfur applications. *Dry scrubbers* include Spray Dryers (SD) and Dry Sorbent Injection (DSI) technologies, and are more compatible with low- to medium-sulfur coals. Some dry scrubber systems can remove 20 to 60 percent of the SO_2, and in some cases up to 90 to 99 percent for HCl and SO_3. DSI technologies are currently being demonstrated on ICI boilers. Furnace Sorbent Injection systems used on cement plants are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent. For SDs, cost per ton of SO_2 removed was in the range of $1,600 to $5,000. Costs were between $1,900 and $3,800 per ton of SO_2 for wet FGDs. While the SO_2 capital costs computed with CUECost for SDs were consistent with the literature at 250 MMBtu/hr, the capital costs computed for wet FGDs were high compared to values reported in the literature.
- *Fuel switching*. While not a control technology *per se*, the emission reduction benefits of fuel switching are directly proportional to the difference in sulfur contents of the fuels. Fuel switching requires considerable cost and operational analyses. In the NESCAUM region, residual oil is commonly used in ICI boilers. Switching from a 3 to a 1 percent sulfur residual oil can provide cost-effective SO_2 reductions at about $771 per ton of SO_2 removed. For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2, as well as in $PM_{2.5}$. The cost of switching to distillate oil is estimated to be much higher than for residual oil, because the higher cost of distillate oil.

6.3 PM Controls

ICI boilers burn a variety of fuels that contain fly ash and thus emit PM. PM control technologies have been commercially available and widely used in EGU boilers for many years. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired boilers. They are very effective in removing total PM and $PM_{2.5}$, with most options removing greater than 99 percent. The options include: (1) *fabric filters or baghouses*; (2) *wet and dry electrostatic precipitators (ESPs)*; (3) *venturi scrubbers*; (4) *cyclones*; and (5) *core separators*. Control technology decisions should be made on a case-by-case basis that accounts for technical, economic, and regulatory considerations. Fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM removed for coal and up to $15,000 per ton of PM removed for oil. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can have a larger parasitic consumption – up to 10 kW/1000 acfm or higher.

APPENDIX A: Survey of Title V Permits in NESCAUM Region

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Solutia Incorporated	MA	Foster Wheeler	249	Coal (Bit. 0.7%S)	-	0.027	baghouse (Carborundum Environmental Systems)	1.2	-	0.525	OFA (Foster wheeler)	-
St. Gobain Abrasives	MA	Riley	230	Coal (Subbit. 0.63%S)	-	0.1	Dust Collector	1.1	-	0.45	LNB	-
UMASS Amherst	MA	Union Iron Works	80	Coal	-	0.12	baghouse	1.1	-	0.43	-	Convert to CHP No. 2 (9/07)
Cooley Dickinson Hospital	MA	Early 1980s	-	Wood	-	-	-	0.008	-	0.16	-	-
Cooley Dickinson Hospital	MA	2006/ AFS Energy Systems	29.88	Wood	-	0.01	Cyclone, Baghouse	0.025	-	0.15	FGR	-
Seaman Paper	MA	2006/ Hurst Boiler	29.88	Wood	-	0.01	Baghouse	0.025	-	0.15	FGR	-

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Cornell University	NY	-	248	Coal	-	0.3	Fabric Filter	Coal 1% S by weight	-	0.4	-	
Cornell University	NY	-	117	Coal	-	0.35	Fabric Filter	Coal 1% S by weight	-	0.4	-	-
Commonwealth Plywood	NY	-	16	Wood	-	-	Multi-Cyclone w/o Fly ash injection	-	-	-	-	-
Crawford Furniture	NY	-	6	Wood	-	-	Single Cyclone	-	-	-	-	-
Deferiet Paper Company	NY	1945/ Combustion Engineering	190	Coal	-	0.46	Multi-Cyclone w/o Fly ash injection, and wet Venturi scrubber	2.5	-	0.5	-	-
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 13

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 14
Eastman Kodak	NY	-	478	Coal (Bit.)	#2 Oil	0.26	ESP	-	-	-	-	Boiler # 15
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 41
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 42
Eastman Kodak	NY	-	640	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 43
Eastman Kodak	NY	-	705	Coal (Bit.)	#2 Oil	0.035	ESP	.6 (coal)	-	0.42	-	Boiler # 44

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Gunlocke Co.	NY	E. Keeler	18	Wood	Oil #2	0.53	Fly Ash Cyclone	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	14.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	41.54	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	27.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Lyonsdale Biomass	NY	Zurn	290	Wood	-	0.1	-	-	-	0.2	-	
Morton International	NY	-	138	Coal	-	0.34	Fabric Filter, ESP	1.7	-	0.5	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
SUNY at Binghamton	NY	International Boiler Works	100	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	X3
SUNY at Binghamton	NY	International Boiler Works	50	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	
US Salt - Watkins Glen Refinery	NY	2000?	160	Coal and/or Wood	NG and/or Coal, Wood	0.051	Fabric Filter	1.2	-	0.18	SNCR	
Dirigo Paper	VT	1977	180	Wood	-	0.20 gr/dscf	multiclone	-	-	0.3	none	-
Ethan Allen	VT	1950	59.5	Wood	-	0.45 gr/dscf	multiclone	-	-	1.94lb/ton wet wood 7.45lb/ton dry wood	none	-
Fraser	NH	1981, Zurn	324	Wood/Bark/Paper	# 6 Oil	0.1	Multi-cyclone + Venturi scrubber	0.8	-	0.25	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Tillotson Rubber	NH	1978	41	Wood	-	0.43	Multi-cyclone	-	-	-	-	
Allen Rogers Limited	NH		5	Wood								
Allen Rogers Limited	NH		5	Wood								
Forest Products Processing Center	NH		47	Wood								
Madison Lumber Mill	NH		13	Wood								
Chick Packaging	NH		10	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Ossipee Mountain Land Company	NH		4	Wood								
Ossipee Mountain Land Company	NH		4	Wood								
Tommila Brothers	NH		11	Wood								
Monadnock Forest Products	NH		30	Wood								
Whitney Brothers Company	NH		2	Wood								
HG Wood Industries	NH		9	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Design Contempo	NH		19	Wood								
Design Contempo	NH		13	Wood								
Solon Manufacturing	NH		9	Wood								
Rochester Shoe Tree/Ashland	NH		4	Wood								
Precision Lumber	NH		9	Wood								
King Forest Industries - Wentworth	NH		29	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Peterboro Basket Company	NH		3	Wood								
Souhegan Wood Products	NH		8	Wood								
Souhegan Wood Products	NH		1	Wood								
Souhegan Wood Products	NH		1	Wood								
Concord Steam Corporation	NH		40	Wood								
Concord Steam Corporation	NH		40	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Boyce Highlands	NH		4	Wood								
Herrick Millwork	NH		5	Wood								
Northland Forest Products	NH		5	Wood								
Anthony Galluzzo Corporation	NH		4	Wood								
Cousineau Wood Products	NH		14	Wood								
Newport Mills Inc	NH		6	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Newport Mills Inc	NH		6	Wood								
Catamount Pellet Corporation	NH		40	Wood								
Durgin & Crowell Lumber Company	NH		10	Wood								
GH Evarts & Company	NH		7	Wood								

References: State Title V Permits, Coal SO_2 Database, ICI Coal Database, MA ICI 100-250 Boiler Database, VT ICI Boiler Database

APPENDIX B: CUECost-ICI Inputs

INPUTS

Description	Units	Input 1	Input 2	Input 3	Input 4	Input 5
General Plant Technical Inputs						
Location - State	Abbrev.	PA	PA	PA	PA	PA
Combustion Configuration	Abbrev.	PC	PC	PC	PC	PC
MW Equivalent of Flue Gas to Control System	MW	25	25.1	28.6	28.6	32.9
Net Plant Heat Rate	Btu/kWhr	10,000	11,370	8,750	8,750	7,600
Plant Capacity Factor	%	66%	66%	66%	66%	66%
Total Air Downstream of Economizer	%	154%	169%	118%	118%	119%
Air Heater Leakage	%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350	350	350	350
Inlet Air Temperature	°F	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013	0.013
Ash Split:						
Fly Ash	%	85%	85%	85%	85%	85%
Bottom Ash	%	15%	15%	15%	15%	15%
Seismic Zone	Integer	1.0	1.0	1.0	1.0	1.0
Retrofit Factor	Integer	1.0	1.0	1.0	1.0	1.0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	2	3	4	5	6
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No	No
Economic Inputs						
Cost Basis -Year Dollars	Year	2006	2006	2006	2006	2006
Service Life (levelization period)	Years	15	15	15	15	15
Inflation Rate	%	3%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	8%	8%	8%	8%	8%
AFDC Rate (current $'s)	%	8%	8%	8%	8%	8%
First-year Carrying Charge (current $'s)	%	22%	22%	22%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%	17%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%	16%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%	12%	12%	12%
Sales Tax	%	6%	6%	6%	6%	6%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	3%	3%	3%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	478.7	478.7	478.7	478.7	478.7
If "No" input escalation rate.	%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%	3%

Operating Labor Rate	$/hr	$25	$25	$25	$25	$25
Power Cost	Mills/kWh	47	47	47	47	47
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs

SO_2 Removal Required	%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2	2
(1 = yes, 2 = no)						
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Reagent Feed Ratio	Factor	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO_2 removed)						
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)						
Number of Absorbers	Integer	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Absorber Pressure Drop	in. H2O	6	6	6	6	6
Reheat Required ?	Integer	1	1	1	1	1
(1 = yes, 2 = no)						
Amount of Reheat	°F	25	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton	$25	$25	$25	$25	$25
Stacking Disposal Cost	$/ton	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO_2 Removal Required	%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147	147
Reagent Feed Ratio	Factor	0.90	0.90	0.90	0.90	0.90
(Mole CaO / Mole Inlet SO_2)						
Recycle Rate	Factor	30	30	30	30	30
(lb recycle / lb lime feed)						
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Spray Dryer Pressure Drop	in. H2O	5	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$60	$60	$60	$60	$60
Dry Waste Disposal Cost	$/ton	$25	$25	$25	$25	$25
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Particulate Control Inputs

Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.03	0.01	0.01	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	6	6	6
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2	2
Gas-to-Cloth Ratio	acfm/ft^2	5.5	5.5	5.5	5.5	5.5
Bag Material (RGFF fiberglass only)	Integer	1	1	1	1	1
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)						
Bag Diameter	inches	6	6	6	6	6
Bag Length	feet	20	20	20	20	20
Bag Reach		3	3	3	3	3
Compartments Out of Service	%	10%	10%	10%	10%	10%
Bag Life	Years	2	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
ESP:						
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0	10.0	10.0
Plate Spacing	in.	12	12	12	12	12
Plate Height	ft.	36	36	36	36	36
Pressure Drop	in. H2O	3	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOx Stoichiometric Ratio	NH3/NOx	0.9	0.9	0.9	0.9	0.9
NOx Reduction Efficiency	Fraction	0.70	0.70	0.70	0.70	0.70
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.4
Space Velocity (Calculated if zero)	1/hr	3000	3000	11800	11800	16800
Overall Catalyst Life	years	4	4	4	4	4
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Catalyst Cost	$/ft3	356.34	356.34	356.34	356.34	356.34
Solid Waste Disposal Cost	$/ton	25.38	25.38	25.38	25.38	25.38
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
Number of Reactors	integer	1	1	1	1	1
Number of Air Preheaters	integer	1	1	1	1	1

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	1:Urea 2:Ammonia	1	1	1	1	1
Number of Injector Levels	integer	3	3	3	3	3
Number of Injectors	integer	18	18	18	18	18
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1	1	1
NOx Reduction Efficiency	Fraction	0.50	0.50	0.50	0.50	0.50
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.2
NH3/NOx Stoichiometric Ratio	NH3/NOx	1.2	1.2	1.2	1.2	1.2
Urea/NOx Stoichiometric Ratio	Urea/NOx	1.2	1.2	1.2	1.2	1.2
Urea Cost	$/ton	200	200	200	200	200
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Water Cost	$/1,000 gal	0.22	0.22	0.22	0.22	0.22
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Low-NOx Burner Technology Inputs

NOx Reduction Efficiency	fraction	0.40	0.40	0.40	0.40	0.40
Boiler Type	T:T-fired, W:Wall	W	W	W	W	W
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%

Natural Gas Reburning Inputs

NOx Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	4.24	4.24	4.24	4.24	4.24
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

November 1, 2018

Alaska Department of Environmental Conservation
Division of Air Quality
ATTN: Director
410 Wiloughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: Second Request for Additional Information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant.

Dear Ms. Koch,

Thank you for the opportunity to provide additional information to better characterize Aurora's operations for the Best Available Control Technology (BACT) Analysis which will be a part of the Serious Area State Implementation Plan.

The following is being provided in response to the information request letter dated September 13, 2018. The ADEC letter included an enclosure with twelve comments for which additional information was requested. Each comment is summarized below followed by a response from Aurora. The information is being submitted to the ADEC by November 1, 2018 as requested.

1. Alternative Fuel Source - Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.

   Response: There are no other economically viable coal options for Aurora. Usibelli Coal Mine is the state's only operating coal mine.

2. Low Excess Air (LEA) and Overfire Air (OFA) - Evaluate these technically feasible control technologies using EPA's top down approach.

   Response: Aurora's BACT analysis dated March of 2017, Section 2.3.2, references the use of combustion controls, including OFA and LEA. The BACT analysis concludes that the Unit 5 (EU 7) is already equipped with OFA, LEA (i.e., oxygen trim system), and air preheaters. It is stated within the BACT that Units 1, 2, and 3 (EU 4-6) have OFA and air preheaters. Although the air preheater ductwork is installed, the preheaters have been removed from operation. The current

configuration of the traveling-grate boilers as installed, includes a 'partial' LEA (i.e., oxygen trim system). The fuel feed rate and oxygen for Boiler Units 1-3 (EU 4-6) are manually adjusted and tuned daily. The traveling-grate boilers have a knife gate which sets the bed thickness and the air-to-fuel ratio is manually adjusted to accommodate the boiler's performance. Once adjusted, the fuel-to-air ratio is maintained automatically.

3. <u>Additional SO_2 Control Technologies</u> - The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO2 removal, and therefore must be included in the analysis.

   <u>Response:</u> - An addendum to the initial BACT submittal was provided to the State on December 22, 2017. This addendum included a substantive analysis of Spray Dry Absorbers (SDA) and Dry Sorbent Injection (DSI) technologies.

4. <u>BACT Limits</u> - Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   <u>Response</u>: Statements concerning applicable standards under 40 CFR Parts 60 (New Source Performance Standards—NSPS) and 61 (National Emission Standards for Hazardous Air Pollutants—NESHAP) are not relevant to the Chena boilers. The NESHAP do not regulate criteria air pollutants such as SO_2, and therefore, no SO_2 floor can be defined by any NESHAP. Furthermore, the Chena boilers are not subject to NSPS and therefore are not required to achieve the NSPS standard. In any case, the NSPS SO_2 emission limit of 1.2 lb/MM Btu (for units less than 75 MM Btu/hr) is achieved in the small boilers (the percent reduction is not a requirement for units less than 75 MM Btu/hr).

   <u>An NSPS or NESHAP standard must be considered as the floor for BACT only when a source is subject to one of the standards</u>. In that case, a source must achieve compliance with the NSPS or NESHAP, and a less stringent emission limit cannot be considered BACT. As noted in a July 28, 1987 memo by Gary McCutchen, then Chief of the New Source Review Section of the US EPA:

   > "Since an <u>*applicable*</u> NSPS must always be met, it provides a legal "floor" for the BACT, which cannot be less stringent." (emphasis added). This statement implies that a source must first be subject to an NSPS for the standard to be considered the BACT floor.

   The Chena plant operates four coal-fired boilers: three at 76.8 MM Btu/hr (22.5 megawatt, MW) heat input and one at 254.7 MM Btu/hr (74.6 MW) heat input. If newly-constructed today, the three smaller units would be subject to an NSPS Subpart Dc limit of 1.2 lb SO_2/MM Btu, and the larger unit would be subject to an NSPS Subpart Da limit of 0.15 lb SO_2/MM Btu. On a Btu-weighted average basis, the overall NSPS limit would be 0.64 lb SO_2/MM Btu. The Chena boilers

currently combust low-sulfur coal, with emissions of 0.39 lb SO_2/MM Btu from the combined exhaust. This overall emission rate represents a 39% reduction from NSPS limits if the Chena boilers had been built today.

Regardless of the NSPS applicability to the Chena boilers, the history of rulemaking for small industrial, commercial, and institutional (ICI) boilers provides valuable insight into the definition of BACT for SO_2 from these units. The three smaller units, if constructed today, would be subject to NSPS Subpart Dc for small ICI boilers. As defined in the standard, ICI units smaller than 22 MW (75 MM Btu/hr) heat input are not subject to a percent reduction requirement in NSPS and instead may achieve compliance with NSPS through the use of low-sulfur fuel. The rationale for this "exemption" is provided in the preamble to the proposed rule (54 *Federal Register* (FR) 24806, June 9, 1989) and the Background Information Document for the Promulgated Standards. As discussed in the Background Document:

> "Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable....Imposing these high (capital and annualized) costs for the units (those less than 22 MW) was considered to be unreasonable when compared to the increase in emission reduction achievable be the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less."

The passage presented above is the basis for the US EPA's definition of BACT for small ICI boilers less than 22 MW. This analysis therefore defines BACT for such units as an emission rate equal to or greater than 1.2 lb SO_2/MM Btu. In the proposed rule, US EPA further states that compliance with this NSPS limit/ BACT emission rate for units smaller than 22 MW (75 MM Btu/hr) can be achieved through use of low-sulfur fuels (see 54 FR 24793). For all practical purposes, the three smaller boilers at the Chena plant fall into this category, and therefore BACT is defined as an emission limit of 1.2 lb SO_2/MM Btu, achieved through combustion of low-sulfur coal. Furthermore, as illustrated above, the four boilers at the Chena plant collectively operate with an actual SO_2 emission level that is 39 percent less than the levels that would be required if all of the units were subject to NSPS.

5. Retrofit Costs - Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

   Response: The BACT cost analysis employed a retrofit factor of 2.0. The basis for this factor was the EPA Air Pollution Control Cost Manual, Sixth Edition. As discussed in the Cost Manual:

   > "To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the

> cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst....The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. Even at detailed cost level (± 5 percent accuracy), vendors will not be able to fully assess the uncertainty associated with a retrofit situation and will include a retrofit factor in their assessments." (see page 2-28 in EPA/452/B-02-001)

As noted in the above citation, US EPA notes that a retrofit factor can be as high as 1.5, this partially supports the value selected for the Chena BACT cost analysis. The cost model employed during the BACT analysis (i.e., CUECost) suggests the following retrofit factors: 1.0 factor for a new facility, a 1.3 factor for a moderately difficult retrofit, and a 1.6 factor for a difficult retrofit. The user is also given the option to input his own retrofit factor based on plant-specific information. As noted by the Northeast States for Coordinated Air Use Management (NESCAUM) in a in a report entitled "Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for industrial, Commercial, and Institutional (ICI) Boilers an independent researcher (Emmel) noted that:

> "this range (of CUECost retrofit factors) significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs (i.e., electric generating units) less than 100 MW. Emmel also noted that on average, a retrofit factor of 1.45 was more reasonable and that the factor should even be higher when CUECost is applied to ICI boilers."

Two main factors impact selection of the retrofit factor for the Chena plant: space availability and equipment congestion. These two factors will require additional efforts for installation, equipment staging, and maneuverability during construction.

6. <u>Baseline Emissions</u> - Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). The baseline is usually the legal limit that would exist, but for the BACT determination.

<u>Response</u>: The Baseline Emission rate is not a legal limit. As stated in the U.S. EPA 1990 New Source Review Workshop Manual:

> <u>"Calculating Baseline Emissions"</u>
>
> The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. *The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions.* In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. (emphasis added)"

Based on this guidance, the Chena baseline emissions were properly calculated and applied to the BACT analysis.

7. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   Response: The current BACT analyses included operating as is, therefore a factor of safety was not included.

8. Good Combustion Practices - For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices.

   Response: Good combustion practices were not proposed. The operation of existing combustion controls (OFA & LEA) were determined to be BACT for NOx.

9. Interest Rate - All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

   Response: Suggest that the State revise interest rate to prime (currently 5.25%) and equipment life to 10 years, not 15, due to corresponding short remaining lifespan of associated boilers.

10. Economic Analysis for Circulating Dry Scrubber (CDS) - Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

    Response: See attached memo "CDS v SDA Cost Comparison.pdf" for CDS analysis.

11. Review State's Spreadsheets – Review cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010.

    Response: Aurora has provided a review of the ADEC's cost effectiveness spreadsheets and inputs. Comments are included on the spreadsheets. Please reference documents "chena-so2-economic-analyses-adec--With ERM Comments.xlsm" and "chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm".

12. Site-Specific Quotes Needed - The cost analyses, particularly for SO2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Response: Included as attachments within this response are vendor quotes as well as a cost analysis for Dry Sorbent Injection (DSI). Due to time constraints, the consultant was able to provide a +50/-30 cost estimate. Please reference the enclosed documents, to include: "Aurora Energy Preliminary Opinion of Probable Cost.pdf"; "Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf"; "BACT Proposal No. 1899-R1.pdf"; and "Aurora_Chena_DSI_General Arrangement.pdf".

Below are a list of documents that are being provided as enclosures which are referenced within the responses given above. If there are any questions pertaining to the information provided, please contact David Fish at dfish@usibelli.com or 907-457-0230.

Sincerely,

David Fish

David Fish
Environmental Manager

Enclosures:

1. CDS v SDA Cost Comparison.pdf
2. chena-so2-economic-analyses-adec--With ERM Comments.xlsm
3. chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm
4. Aurora Energy Preliminary Opinion of Probable Cost.pdf
5. Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf
6. BACT Proposal No. 1899-R1.pdf
7. Aurora_Chena_DSI_General Arrangement.pdf
8. Unified Facilities Criteria (UFC) DoD Facilities Pricing Guide (ufc_3_701_01_c1_2018.pdf)
9. ufc_3_701_01_data_tables_may_2018.xlsx
10. NSPS ICI SO2 RE.docx
11. ICI Boilers 20081118 final_revised-Jan2009.pdf
12. EPA Air Pollution Cost Control Manual, sixth edition, January 2002, accessible at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf.

Cc:

Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Denise Koch, ADEC/ Air Quality
Cindy Heil, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/ Air Quality
Buki Wright/ Aurora Energy, LLC
Rob Brown/ Usibelli Coal Mine, Inc.
Tim Hamlin/ EPA Region 10
Dan Brown/ EPA Region 10
Zach Hedgpeth/ EPA Region 10

Stanley Consultants INC.		Rev. 0	Job No.	28709.01.00	Page No.	1
			Subject	Aurora Energy Chena - Dry Sorbent Injection		
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 10/29/2018		Opinion of Probable Cost		
Checked by	J. Solan	Date 10/29/2018				
Approved by	C. Spooner	Date 10/30/2018	Sheet No.	1	of	1

Item Description		Quantity No. of Unit	UOM	Unit Cost	Total Cost
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,880,200.00	$1,880,200
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	$6,370,000.00	$6,370,000
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	$238.00	$71,400
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$239.00	$74,090
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$239.00	$66,920
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$239.00	$47,800
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	$14,169,111
				Mobilization & Demobilization - 5%	$708,456
				Bond - 2.5%	$354,228
				Contractor Overhead - 10%	$1,416,911
				Contractor Profit - 10%	$1,416,911
				Total Construction Cost	$18,065,617
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$736,199
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,802,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,682,000**

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.

STANLEYCONSULTANTS, Inc

8000 South Chester Street › Suite 500 › Centennial, CO 80112
303.799.6806 › stanleyconsultants.com

November 1, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Qualitative Cost Comparison of Circulating Dry Scrubber Technology Versus Spray Dryer Absorbers

David:

Per your request Jason Smith and I have developed a comparison between the Circulating Dry Scrubber and Spray Dry Absorption technologies and the expected differences in total installed cost. Jason is an expert in SO_2 scrubbers having participated in the construction, startup, and commissioning of several installations over the course of his career.

The two commercially available semi-dry acid gas scrubbing processes consist of Spray Dryer Absorption (SDA) and Circulating Dry Scrubber (CDS). Both technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with sulfur dioxide (SO2) and sulfur trioxide (SO3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash is 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 process also depend on the humidification of the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduced 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 humidification of the flue gas stream 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 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 pumped, the SDA process can sometimes leverage existing infrastructure such as existing particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system serves to limit 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, just to name a few.

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 typically occurs after a venturi assembly that increases the velocity of the passing gas stream to establish a fluidized bed of alkaline material. The flue gas then passes through this bed and 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 collector be placed at higher elevations. This will ensure that the proper slope is maintained between the collector and the injection point on the absorber tower. It is technically challenging to take an existing 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 to accommodate the higher elevation construct to be handled under a single contract, thus limiting risk for the owner. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the necessary capital outlay for the 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 does not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in a significantly larger installation cost when compared to an equivalent SDA system. Given that the ADEC Preliminary BACT Determination for the Chena Plant (Dated March 22, 2018) has already established that a SDA system is not economically feasible (Table 4-3, Page 12), it can therefore be concluded that the CDS system is economically infeasible as well.

Please let me know if you have any questions or comments regarding the information presented in this letter.

Sincerely,

John P Solan

John P. Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

Members of Northeast States for Coordinated Air Use Management

Arthur Marin, Executive Director
Northeast States for Coordinated Air Use Management

Anne Gobin, Bureau Chief
Connecticut Department of Environmental Protection, Bureau of Air Management

James P. Brooks, Bureau Director
Maine Department of Environmental Protection, Bureau of Air Quality

Barbara Kwetz, Director
Massachusetts Department of Environmental Protection, Bureau of Waste Prevention

Robert Scott, Director
New Hampshire Department of Environmental Services, Air Resources Division

William O'Sullivan, Director
New Jersey Department of Environmental Protection, Office of Air Quality Management

David Shaw, Director
New York Department of Environmental Conservation, Division of Air Resources

Douglas L. McVay, Acting Chief
Rhode Island Department of Environmental Management, Office of Air Resources

Richard A. Valentinetti, Director
Vermont Department of Environmental Conservation, Air Pollution Control Division

UNITS, SPECIES, ACRONYMS

Acronyms
APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
BOOS – Burners Out of Service
CAA – Clean Air Act
CAAA – Clean Air Act Amendments (of 1990)
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – Electrostatic Precipitators
FBC – Fluidized Bed Combustion
FF – Fabric Filter (also known as baghouse)
FGD – Flue Gas Desulfurization (also known as SO_2 scrubber)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
FSI – Furnace Sorbent Injection
GR – Gas Reburn
HHV – Higher Heating Value
ICI – Industrial, Commercial, and Institutional (boilers)
LAER – Lowest Achievable Emission Rate
LNB – Low-NOx Burner
LSDI – Lime Slurry Duct Injection
LSFO – Limestone Forced Oxidation
LSC – Low-Sulfur Coal (also known as compliance coal)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic-Northeast Visibility Union
MC – Mechanical Collector
NAAQS – National Ambient Air Quality Standard
NCG – Non-Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standards
NSR – Normalized Stoichiometric Ratio
OFA – Overfire Air
PC – Pulverized Coal
PRB – Powder River Basin (coal)
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SCA – Specific Collection Area
SCR – Selective Catalytic Reduction

SD – Spray Dryer
SIP – State Implementation Plan
SNCR – Selective Non-Catalytic Reduction
TCR – Total Capital Requirement
TR – Transformer Rectifier
UBC – Unburned Carbon
US EIA – United States Energy Information Administration
US EPA – United States Environmental Protection Agency
ULNB – Ultra Low-NOx Burner
VOM – Variable Operating and Maintenance (costs)
WESP – Wet Electrostatic Precipitator
WFGD – Wet Flue Gas Desulfurization (also known as wet SO_2 scrubber)

Chemical Species
HCl – Hydrochloric Acid
HF – Hydrofluoric Acid
H_2SO_4 – Sulfuric Acid
NOx – Oxides of Nitrogen (NO_2 and NO)
NO – Nitric Oxide
NO_2 – Nitrogen Dioxide
NH_3 – Ammonia
$PM_{2.5}$ – Particulate Matter up to 2.5 μm diameter in size
PM_{10} – Particulate Matter up to 10 μm diameter in size
S – Sulfur
SO_2 – Sulfur Dioxide
SO_4 – Sulfate
VOC – Volatile Organic Compound

Units
Length
m – meter
μm – micrometer or micron (0.000001 m; 10^{-6} m)
km – kilometer (1000 m; 10^{3} m)
Mm – Megameter (1,000,000 m; 10^{6} m)

Flow Rate
acfm – actual cubic feet per minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 g; 10^{-6} g)

kg – kilograms (1000 g; 10^3 g)

Force
psi – pounds per square inch

Power
W – watt (Joules/sec)
kW – kilowatt (1000 W; 10^3 W)
MW – megawatt (1,000,000 W; 10^6 W)

Energy
Btu – British thermal unit (= 1055 Joules)
MMBtu – million Btu
MWhr – megawatt-hour
kWhr – kilowatt-hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Project Director

Praveen Amar, Ph.D., P.E., Director, Science and Policy, NESCAUM

Principal Contributors

Constance L. Senior, Ph.D., Reaction Engineering International
Rui Afonso, Energy and Environmental Strategies

Acknowledgments

NESCAUM gratefully acknowledges the funding support provided by the United States Environmental Protection Agency (Clean Air Markets Division (CAMD) and Office of Air Quality Planning and Standards (OAQPS)). Mr. Sikander Khan (CAMD) and Mr. Tim Smith (OAQPS) acted as the Project Managers and Mr. Gene Sun was the Grant Manager.

This report was managed and directed by NESCAUM (Dr. Praveen Amar). NESCAUM was very ably supported by its contractors, Reaction Engineering International (Dr. Constance L. Senior) and Energy and Environmental Strategies (Mr. Rui Afonso). Additionally, Mr. Addison Faler, a student intern at NESCAUM, did extensive data analysis of emission estimates from industrial, commercial, and institutional boilers in the Northeast and the US. Ms. Wendy Roy, Administrative Assistant, NESCAUM, was extremely helpful in final formatting of the report.

NESCAUM thanks the members of the NESCAUM Stationary Sources and Permitting Committee, who guided the design of this report in early stages and provided access to the operating permits data, included in this report. The following individuals provided strong technical support and comments on various draft versions of this report:

Andrew Bodnarik, New Hampshire Department of Environmental Services

Sunila Agrawal, New Jersey Department of Environmental Protection

NESCAUM is an association of the eight northeast state air pollution control programs and provides technical guidance and policy advice to its member states.

TABLE OF CONTENTS

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EXECUTIVE SUMMARY

ES-1 Objectives

The main objective of this study is to evaluate the viability of technologies for controlling emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) from industrial, commercial, and institutional (ICI) boilers. These pollutants contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. This source sector is coming under increased scrutiny by air quality regulators needing emission reductions to meet Clean Air Act requirements.

This study also includes a literature review of emission control costs and develops methods for estimating the costs and cost effectiveness of air pollution controls for ICI boilers. The study concludes that ICI boilers are a significant source of emissions, are relatively uncontrolled compared to electricity-generating units (EGUs), and offer the potential to achieve cost effective reductions for all three pollutants. The results of this technical and economic evaluation are intended as a resource in assessing regulatory and compliance strategies for ICI boilers.

Most of the technologies considered in this report have been successfully applied to the larger EGU boilers. This study investigates both the feasibility of down-scaling such control technologies for ICI boiler applications and of certain technologies that have not been applied to EGUs, but show promise for the ICI boilers.

ES-2 Report Organization

Chapter One provides an overview of the ICI boiler fleet in terms of boiler size, applications, fuel type and associated emissions. Chapters Two, Three, and Four discuss control technology options for NOx, SO_2 and PM, respectively. Each chapter provides: (1) descriptions of available control technologies; (2) a discussion of the applicability of these technologies to ICI boilers; (3) published cost estimates; and (4) an assessment of the impact of control technologies on overall facility efficiency. Chapter Five summarizes information about air pollution control equipment costs for ICI boilers calculated with the Coal Utility Environmental Cost (CUECost) model.

ES-3 Differences between ICI and EGU Boilers

ICI and EGU boilers differ in size, application, design, and emissions. Most commercial and institutional boilers are relatively small, with an average capacity of 17 MMBtu/hour. Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. By contrast, the average size of a coal-fired EGU boiler in the U.S. is greater than 2,000 MMBtu/hr.

All coal-fired EGUs in the United States are equipped with PM control devices and many have SO_2 and NOx emission controls. ICI boilers are significantly less likely to have air pollution control devices.

As part of this study, NESCAUM conducted a preliminary survey of the use of emission controls on ICI boilers in the Northeast. Survey results revealed that more than half of the units surveyed in the region had no controls; about one-third had PM controls, while very few units

had NOx controls. None of the surveyed units had SO_2 controls, although some have wet venturi scrubbers for PM control, which minimally reduce SO_2 emissions.

Technical, operational, economic and regulatory factors impose different opportunities and constraints on the applicability of air pollution control devices (APCDs) for EGU and ICI boilers. The following technical and operational characteristics must be evaluated in determining the potential applicability of emission controls for specific ICI boilers.

- Fuel type and quality – SO_2, PM, and NOx emissions from coal-fired boilers are typically higher than from those burning natural gas, oil, or wood waste. Some APCD technologies are not particularly sensitive to such variations. For example, an electrostatic precipitator (ESP) or a fabric filter (FF) can accommodate different PM concentrations, although the type and size of PM and gas temperatures will have an impact. Other controls that utilize reagents, such as SO_2 scrubbers and selective catalytic reduction or selective non-catalytic reduction (SCR/SNCR) technologies for NOx, are directly affected by fuel type and quality.
- Duty cycle – APCD controls must be capable of accommodating significant variation or cycling of boiler loads. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – The presence of equipment such as economizers or air preheaters has a direct impact on flue gas temperatures. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers, and SCR/SNCR that are widely used in EGUs may or may not be applicable to ICI boilers in certain cases.

ES-4 NOx Control Technologies

Emission control strategies for NOx can be divided into two basic categories: combustion modifications and post-combustion technologies. Control efficiency ranges and cost effectiveness ($/ton of NOx removed) for various technologies are provided in Table ES-1. Combustion modification technologies, which minimize the formation of NOx during the combustion process, include: combustion tuning; low-NOx burners and overfire air (LNBs and OFA); and gas, oil, or coal reburn.

LNBs have minimal effect on overall operating costs, but may introduce higher carbon monoxide and/or carbon levels in the fly ash, which reflect lower plant efficiency. In the case of gas reburn, operating costs are primarily a function of the fuel cost differential; for coal or oil reburn, fuel preparation costs (pulverization and atomization, respectively) represent the primary operating and maintenance costs. While gas reburn is easier to implement, the fuel differential costs are often prohibitive. The overall cost of low-NOx combustion technology installation depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity.

Post-combustion technologies reduce the amount of NOx exiting the stack that was formed during combustion. This group includes SNCR, SCR, and regenerative SCR (RSCR) technologies. Because the reaction occurs without the need for catalysts, SNCR systems have

lower capital costs, but achieve lower NOx reduction. SCR, on the other hand, is capital-intensive, but offers the opportunity for significantly greater NOx reductions because a dedicated reactor and a reaction-promoting catalyst ensure a highly controlled, efficient reaction. RSCR combines a regenerative thermal oxidizer with SCR technology, making it suitable for facilities with lower gas temperatures, such as those found in some ICI boilers. RSCRs can also reduce carbon monoxide emissions by half.

ES-5 SO_2 Control Technologies

SO_2 emission control technologies are post-combustion devices that utilize a process involving SO_2 reacting in the exhaust gas with a reagent (usually calcium- or sodium-based) and removal of the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 control technologies are commonly referred to as flue gas desulfurization (FGD) and/or "scrubbers" and are usually characterized in terms of the process conditions (wet vs. dry), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable). Wet scrubbers provide much greater levels of SO_2 control. Conventional dry processes include spray dryers (SDs) and dry sorbent injection (DSI). The capital costs of wet scrubbers are higher than those of dry scrubbers, although the cost effectiveness values (in dollars per ton of SO_2 removed) of wet and dry processes are similar. DSI technology has a significantly lower capital cost than wet or dry scrubbers and should therefore be more attractive for ICI boilers than conventional scrubbers.

In the eight-state NESCAUM region, residual oil is a common fuel for ICI boilers. Switching to a lower sulfur residual oil (for example, from 3 percent to 1 percent sulfur residual oil) can provide cost-effective SO_2 reductions. The cost of switching to lower sulfur distillate oil is much higher than switching to low sulfur residual oil, because the cost of distillate oil has been about twice that of residual oil in recent years. The cost effectiveness (in dollars per ton of SO_2 removed) from switching from residual fuel oil to distillate fuel oil is not as attractive and falls in the range of the cost effectiveness of installing a FGD scrubber.

ES-6 PM Control Technologies

Combustion processes emit both primary and secondary particulate matter. Primary emissions consist mostly of fly ash (e.g., non-combustible inorganic matter and unburned solid carbon). Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter. PM control technologies include: fabric filters or "baghouses," wet and dry ESPs, venturi scrubbers, cyclones, and core separators. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired ICI boilers.

ES-7 Impact of Control Technologies on Operational Efficiency and Carbon Dioxide Emissions

Air pollution control technologies and strategies (e.g., fuel switching) can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative depending on technology and fuel choices.

Carbon dioxide (CO_2) emissions are primarily a function of the carbon content of fuels. However, the application of conventional pollutant control technologies can affect CO_2 emissions. This impact can vary widely among technologies within the same pollutant (e.g.,

LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. scrubbers for SO_2).

Combustion modification technologies for NOx have essentially no impact on the CO_2 emissions of the host boilers – with the noted exception of reburn when displacing coal or oil with natural gas – because the technologies do not impose any significant parasitic energy consumption (auxiliary power) requirements. With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy demand on the host boiler. These impacts include pressure, compressor, vaporization, and steam losses, and can range from 1–2 kW/1000 actual cubic feet per minute (acfm) for SNCR and up to about 4 kW/1000 acfm for SCR.

The major components affecting energy consumption for SO_2 systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. The power consumption of the SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. SO_2 controls have a range of potential parasitic losses, from duct injection representing about 1–2 kW/1000 acfm to wet FGD at as high as 8 kW/1000 acfm.

PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can be up to 10 kW/1000 acfm or higher.

ES-8 Cost Analysis

Cost is an important factor in evaluating the viability of air pollution control technologies. Information on capital and operating costs is more readily available for EGU than ICI boilers. Operating costs may be different for ICI boilers than utility boilers because of their size and the fact that they are typically located on smaller sites. Operating costs also include waste disposal and reagent use. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs, as a percentage of total capital cost, than those for utility boilers.

Cost estimates for ICI boilers with capacities ranging from 100 to 250 MMBtu/hr were generated by the CUECost model. This model, created by Raytheon Engineers for US EPA, was originally developed for large coal-fired EGUs and calculates capital and operating costs for certain pre-defined air pollution control devices for NOx, SO_2, and PM. The CUECost model produces approximate estimates (±30 percent accuracy) of installed capital and annualized operating costs. The CUECost model was adapted in this study for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. This study represents the first attempt to utilize a comprehensive cost model specific to ICI boilers.

Chapter Two contains a detailed discussion of the literature values for NOx control costs for ICI boilers. The NOx control costs for ICI boilers computed with CUECost were largely consistent with values reported in the literature. In terms of NOx removal, reported values were in the range of $1,000 to $3,000 per ton for LNBs or SNCR, and $2,000 to $14,000 per ton for SCR. The SCR costs for coal-fired ICI boilers appear to be consistent with the literature, although the CUECost capital cost values for residual oil were higher than the literature values. The capital costs for SNCR calculated from the CUECost models were in good agreement with literature values, particularly their sensitivity to boiler capacity. The capital costs for LNBs

calculated from CUECost for coal-fired boilers were consistent with the literature values, although the costs for residual oil-fired boilers were higher in CUECost than the literature values.

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs for ICI boilers. In terms of the cost per ton of SO_2 removed, reported values were in the range of \$1,600 to \$5,000 for spray dryers (SDs) and \$1,900 to \$5,200, for wet FGDs. The SO_2 capital costs computed with CUECost for SDs were in the range of the literature values at 250 MMBtu/hr. However, the capital costs computed by CUECost for wet FGDs were high compared to values reported in the literature.

Chapter Four contains a detailed discussion of the literature values for PM control costs. Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to industrial boilers. The cost effectiveness of ESPs was in the range of \$50 to \$500 per ton of PM for coal, and up to \$20,000 per ton of PM for oil. The cost effectiveness of baghouses was in the range of \$50 to \$1,000 per ton of PM for coal and up to \$15,000 per ton of PM for oil.

The dry-ESP control costs computed with CUECost were consistent with the literature values, although the CUECost predicted slightly higher values than reported by EPA for dry, wire-plate ESPs. The baghouse/fabric filter costs computed with CUECost were higher than the literature values for pulse-jet fabric filters.

This adaptation of CUECost model from EGUs to ICI boilers was intended to investigate the feasibility of estimating costs of controlling emissions of NOx, SO_2, and PM from ICI boilers. Further detailed work would be needed to validate this approach, but initial results included in this report are promising.

ES-9 Conclusion

ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. These boilers are relatively uncontrolled compared to EGUs and offer the potential to achieve cost-effective reductions for all three pollutants. A host of proven emission control technologies for EGUs can be scaled-down and deployed in industrial, commercial, and institutional settings to cost-effectively reduce emissions of concern. Other technologies that have not been applied to EGUs show promise for ICI boiler applications. Careful analysis will be needed to match the appropriate emission control technology for specific applications given: boiler size, fuel type/quality, duty-cycle, and design characteristics. Further, regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls.

Table ES-1. ICI Boiler Control Technologies

Pollutant	Technology	Control Efficiency	Cost Effectiveness $ per ton
NOx			
Combustion Modifications	Tuning	5-15%	current data not available
	LNB	25-55%	$750-$7,500
	Reburn	35-60%	current data not available
Post-Combustion	SNCR	30-70%	$1,300-$3,700
	SCR	70-90%	$2,200-$14,400
	RSCR	60-75%	$4,500
SO_2	Wet Scrubbers	95+%	$1,900-$5,200
	Spray Dryers	90-95%	$1,600-$5,200
	Dry Sorbent Injection	40-90%	current data not available
PM			
	Fabric Filters/Baghouses	99+%	$400-$1,000 – coal $6,900-$16,500- oil
	Wet/Dry ESPs	99+%	$160-$2,600 – coal $2,300 to $43,000 - oil
	Venturi Scrubbers	50-90%	current data not available
	Cyclones	70-90%	current data not available
	Core Separators	60-75%	current data not available

1 INTRODUCTION

1.1 Objectives

The main objective of this study is to evaluate various available control technologies and their cost effectiveness in reducing emissions of three pollutants: oxides of nitrogen (NOx), sulfur dioxide (SO_2), and primary fine particulate matter ($PM_{2.5}$) from industrial, commercial, and institutional (ICI) boilers. The study results should provide a strong technical and economic basis for developing cost-effective regulations and strategies to reduce emissions of these three major pollutants from ICI boilers.

1.2 Regulatory Drivers

Federal, state and local governments regulate all major criteria air pollutants under the authority of the Clean Air Act (CAA). The CAA mandates control of pollutants such as NOx, SO_2, and $PM_{2.5}$ to attain and maintain National Ambient Air Quality Standards (NAAQSs) for ozone and $PM_{2.5}$, reduce acidic deposition, and improve visibility under regional haze regulations. Emission standards for specific source categories, including ICI boilers, are also set by federal, state, and local governments to attain and maintain a NAAQS. Examples of these emission standards include New Source Performance Standards (NSPS), Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Reasonably Available Control Technology (RACT), and Best Available Retrofit Technology (BART).

States must formulate State Implementation Plans (SIPs) that provide a framework for limiting air emissions from major sources as part of a strategy for demonstrating attainment and maintenance of NAAQS. Some individual SIPs (if allowed by the state law) may set more stringent limits on emissions of NOx, SO_2, and $PM_{2.5}$ than required by the federal rules. However, states cannot set less stringent limits than required by federal rules and regulations. Generally, federal, state, and local permitting authorities rely upon available information on the latest advanced technologies for emission control when setting emission limits. Where applicable, permitting authorities require BACT and RACT in order to reduce air emissions from stationary sources. In areas that have not achieved a NAAQS (i.e., non-attainment areas), the CAA requires air pollution limits established by LAER for new major stationary sources and major modifications to existing stationary sources. BACT and RACT analyses consider the cost of controls. LAER control technologies, applicable to new major sources located in non-attainment areas, must be installed, operated and maintained without consideration of costs.

1.3 Characterization of Combustion Sources

1.3.1 Description of Combustion Sources

Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines.

Boiler size is typically represented in four ways: fuel input in units of MMBtu/hr, output of steam in lb steam/hr at a specified temperature and pressure, boiler horsepower (1 boiler hp = 33,475 MMBtu/hr), or electrical output in MWhr or MW (if electricity is generated).

The three main types of boilers are described below:

- *Firetube boilers*. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 MMBtu/hr.
- *Watertube boilers*. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a “wall.” Watertube boilers vary in size from less than 10 MMBtu/hr to10,000 MMBtu/hr.
- *Fuel-firing*. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal (PC) enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to “suspend” the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

Boilers are also classified by the fuel they use – chiefly coal, oil, natural gas, wood, and waste byproducts.

1.3.2 Emissions by Size, Fuel, and Industry Sector

In 2005, Energy & Environmental Analysis, Inc. [EEA, 2005] estimated that there were 162,805 industrial and commercial boilers in the U.S., which had a total fuel input capacity of 2.7 million MMBtu/hr as summarized in Figure 1-1 and Table 1-1. This estimate included 43,015 industrial boilers with a total capacity of 1.6 million MMBtu/hr and 119,790 commercial boilers with a total capacity of 1.1 million MMBtu/hr. In addition, EEA estimated that there were approximately 16,000 industrial boilers in the non-manufacturing sector with a total capacity of 260,000 MMBtu/hr, but details on size distribution of these boilers were not provided because these units were not well characterized.

The EEA report divided boilers into two major categories (industrial and commercial) instead of the more common characterization as industrial, commercial, and institutional boilers. One segment of the ICI boiler population, identified as non-manufacturing industrial boilers, is not included in the EEA analyses due to a lack of sufficient data. The non-manufacturing segment accounted for only 11 percent of energy consumption in the industrial boiler population. The manufacturing and non-manufacturing segment of the population appear (from EEA’s description) to correspond to what would be called industrial boilers. The commercial segment of the population includes what are designated in this report as commercial and institutional boilers. For example, there are several large boilers located at major institutions such as universities (e.g., Notre Dame, Cornell, etc.) and also several large boilers located at major hospitals (e.g., Massachusetts General Hospital) that belong in the institutional category instead

of the commercial sector. Thus, EEA's analysis appears to apply to most of the ICI boiler population, representing 89 percent of energy use by ICI boilers.

Industrial boilers were generally larger than commercial units. Sixty percent of the boilers in the manufacturing sector were greater than 100 MMBtu/hr in capacity, whereas 60 percent of the boilers in the commercial sector were in the range of 10 to 100 MMBtu/hr. The average capacity of the commercial boilers was 10 MMBtu/hr, with most less than 10 MMBtu/hr; the capacity of the average industrial boiler was 36 MMBtu/hr. Non-manufacturing boilers fell in between, at an average capacity of 16 MMBtu/hr. For industrial boilers, the average capacity factor was 47 percent (capacity factor is defined as the ratio of actual heat input in MMBtu to the maximum heat input based on nameplate capacity of the unit, calculated for a period of one year).

Table 1-1. Capacity of industrial boilers [EEA, 2005]

Unit Capacity	Manufacturing Boilers	Non-Mfg Boilers*	Commercial Boilers	Total
<10 MMBtu/hr	102,306	---	301,202	403,508
10-50 MMBtu/hr	277,810	---	463,685	741,495
50-100 MMBtu/hr	243,128	---	208,980	452,108
100-250 MMBtu/hr	327,327	---	140,110	467,437
>250 MMBtu/hr	616,209	---	33,639	649,848
Total Capacity, MMBtu/hr	1,566,780	260,000	1,147,617	2,714,397
Total Capacity >10 MMBtu/hr	1,464,474	---	846,415	2,310,889**
Total number of units	43,015	16,000	119,790	162,805
Average Capacity, MMBtu/hr	36	16	10	17

*No details provided on range of capacities
**Total does not include non-manufacturing boilers

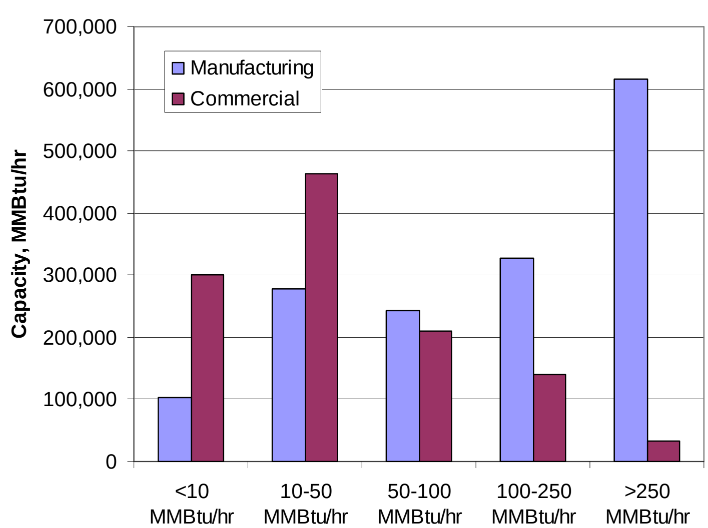


Figure 1-1. Total capacity of industrial boilers as a function of size [EEA, 2005]

Five major steam-intensive industries accounted for more than 70 percent of the boiler units and more than 80 percent of the boiler capacity of the manufacturing segment of industrial boilers: food, paper, chemicals, petroleum refining, and primary metals. The non-manufacturing segment of the industrial sector included agriculture, mining and construction. The largest categories in the commercial sector, by capacity, were schools, hospitals, lodgings, and office buildings.

Industrial boilers in the manufacturing sector are used to generate process steam and electricity. The fuels used in manufacturing boilers are related to the size of the boilers and, in some cases, the byproducts generated in the particular manufacturing process.

In the food production subsector, the average boiler capacity was 20 MMBtu/hr. The relatively small average capacity was reflected in the higher percentage (58 percent) of natural gas-fired boilers in the food industry than in any other major subsector, since very small boilers tend to burn natural gas.

The paper industry included some of the largest industrial boilers, with an average boiler size of 109 MMBtu/hr. The paper industry represented more than half (230,000 MMBtu/hr) of the total capacity of the manufacturing sector. More than 60 percent of the fuel used in paper industry boilers was wood (bark, wood chips, etc.) or black liquor, a waste product from the chemical pulping process.

The chemical industry employed both large and small boilers, with about seven percent of the units with capacities smaller than 10 MMBtu/hr, and a significant number (about 350 or 37 percent of total capacity) larger than 250 MMBtu/hr. The primary fuels for chemical industry boilers were natural gas (43 percent), process off-gas (39 percent), and coke (15 percent).

The refining industry had an average boiler size of 143 MMBtu/hr, the largest of any of the major industries, with over 200 boilers with capacities above 250 MMBtu/hr. By-product fuels (refinery gas or carbon monoxide) were the most common fuel source for boilers (58 percent), followed by natural gas (29 percent) and residual oil (11 percent).

About half of the total boiler capacity in the primary metals industry was from boilers larger than 100 MMBtu/hr. By-product fuels, like coke oven gas and blast furnace gas, provided the largest share (63 percent) of boiler fuel in the primary metals industry.

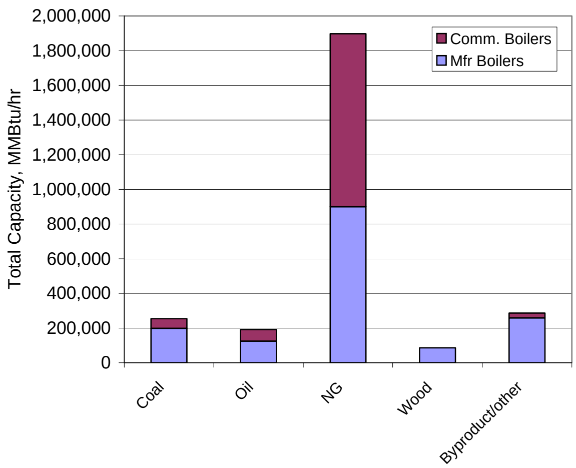
The remaining industries accounted for about 29 percent of manufacturing boilers (12,000 units) or about 18 percent of industrial boiler capacity. The average capacity for the rest of the manufacturing subsector was 23 MMBtu/hr. Approximately 100 boilers at other manufacturing facilities had capacities larger than 250 MMBtu/hr.

Unlike industrial boilers, which serve production processes, commercial boilers provide space heating and hot water for buildings. Natural gas fired the vast majority of commercial boilers, including 85 percent of commercial boiler units and 87 percent of the total commercial boiler capacity. About 10 percent of the commercial boilers were fired by oil. Coal was fired at about one percent of the commercial boilers, but represented five percent of the capacity, reflecting the larger size of commercial coal-fired boilers.

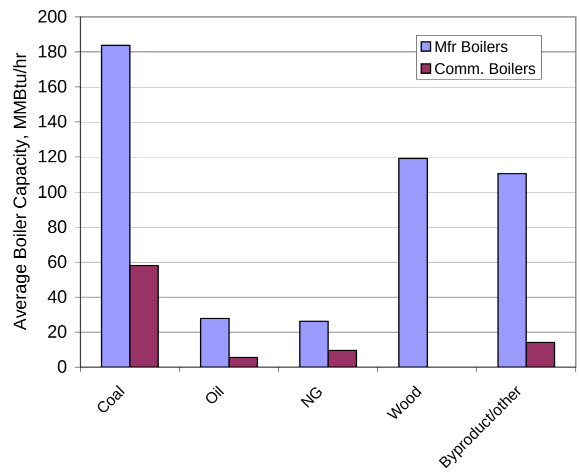
Figure 1-2 summarizes the total US boiler capacity in the manufacturing and commercial sectors as a function of fuel fired (left side of figure) and shows the average capacity per boiler (right side of figure) by fuel type. Coal-fired boilers were the largest in size on average. As discussed above, natural gas accounted for 70 percent of the total industrial boiler capacity in the

EEA survey. Coal and byproduct fuels accounted for about 10 percent each, with lesser capacity in oil- and wood-fired boilers.

In the manufacturing sector, the average coal-fired boiler capacity was about 180 MMBtu/hr, but the average capacity in both sectors combined was about 125 MMBtu/hr. Wood- and byproduct-fired boilers in the manufacturing sector were also large on average (120 and 110 MMBtu/hr, respectively). On the other hand, oil- and natural gas-fired boilers were small, on the order of 20 MMBtu/hr in the manufacturing sector and less than 10 MMBtu/hr in the commercial sector.



(a) Total capacity by fuel and sector



(b) Average capacity by fuel and sector

Figure 1-2. Total and average boiler capacity of U.S. industrial boilers as a function of fuel fired [EAA, 2005]

From EEA's 2005 study, the following general conclusions about boiler size for the entire U.S. ICI boiler population can be drawn:

- natural gas is the fuel fired at most ICI boilers;
- natural gas- and oil-fired boilers tend to be small, less than 20 MMBtu/hr in capacity;
- boilers fired with coal, wood, or process byproducts are larger in size, greater than 100 MMBtu/hr on average;
- although natural gas fired most of the ICI boilers in the U.S., coal, oil, and wood contribute substantially more to the emissions of SO_2 and PM; and
- all fuels are sources of NOx emissions.

One needs to be careful drawing conclusions for the eight-state NESCAUM region based on the national data in the EEA 2005 study because there are large region-to-region and state-to-state differences in boiler populations. For example, fuel oil is an important fuel in the Northeast, especially in rural areas where natural gas may not be available, while natural gas is predominant in other areas of the country.

A preliminary assessment of emissions from ICI boilers by pollutant in the U.S. and in the eight-state NESCAUM region was carried out using data from the AirData database via the EPA website (www.epa.gov/air/data). In this database, stationary sources, such as electric generating plants and factories, are identified individually by name and location. Figure 1-3 compares the annual emission of NOx, SO_2, and $PM_{2.5}$ in the U.S. with the eight-state NESCAUM region for 2002. Emissions in the NESCAUM region are about 5 percent of the US total emissions.

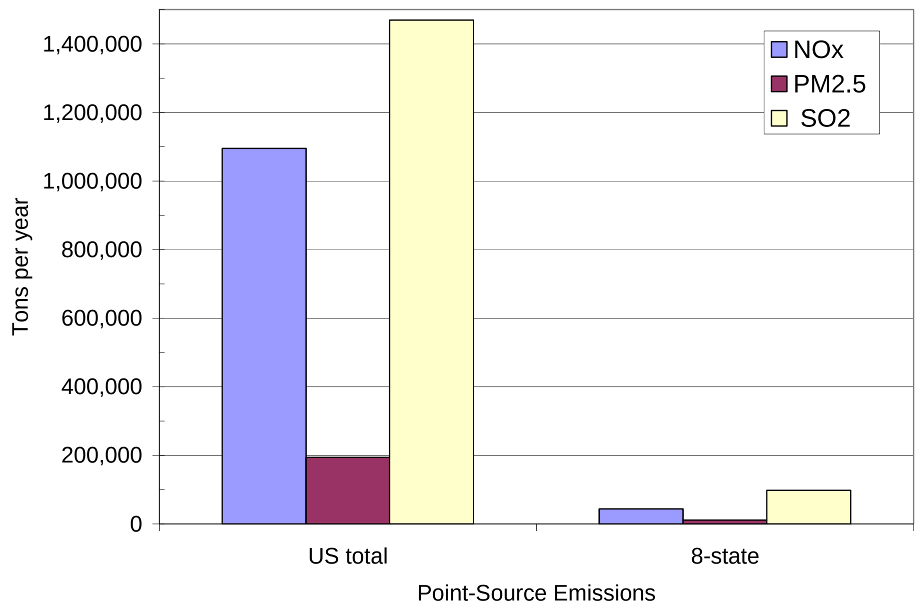


Figure 1-3 Total annual emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the U.S. and in the eight-state region from EPA AirData database

Another set of data from the eight-state region was extracted from the MANEVU 2002 non-road inventory (www.manevu.org). In this data set, oil-fired boilers were divided into distillate oil and residual oil-fired boilers (Figure 1-4).

NOx emissions in the eight-state NESCAUM region are mostly from oil- and gas-fired boilers. Because these are generally small boilers, combustion controls are good candidates for NOx control. For larger, coal- or wood-fired boilers, SNCR or SCR might also be applicable.

PM emissions are relatively low from coal-fired sources in the eight-state region, which suggests that most of the coal-fired sources already have particulate control devices. Oil- and wood-fired units have higher PM emissions, and PM emissions attributed to natural gas are quite small.

As might be expected, most of the SO_2 emissions from oil-fired boilers come from residual oil-fired boilers because of residual oil's higher sulfur content.

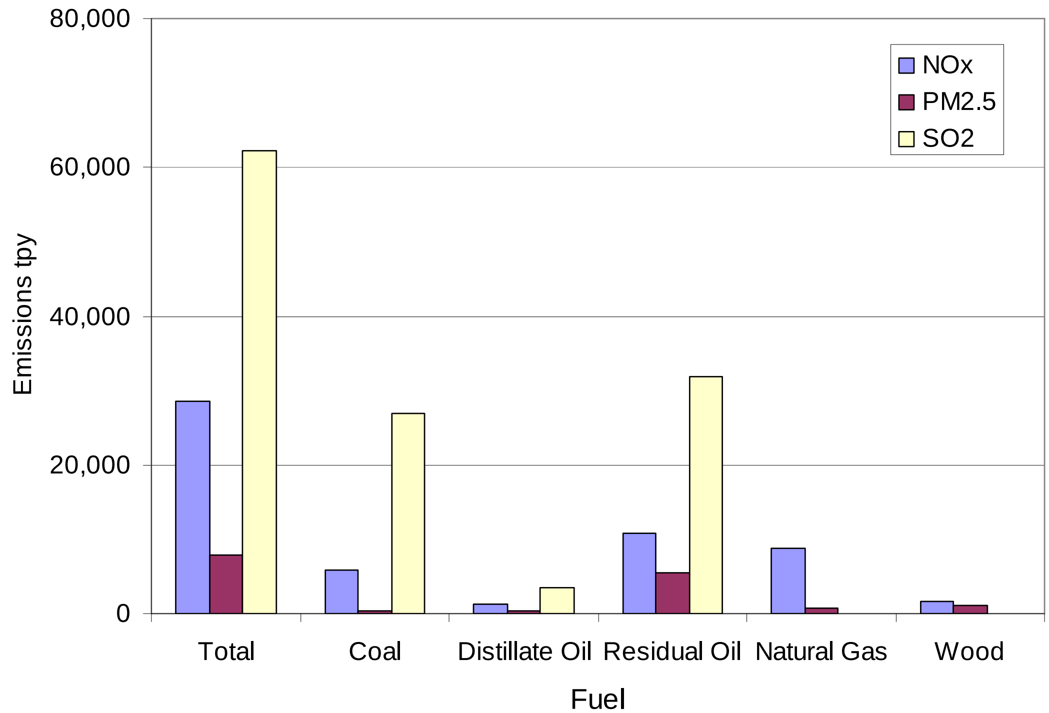


Figure 1-4. Emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the NESCAUM region from MANEVU database as a function of fuel fired

1.3.3 Differences between EGU and ICI boilers

EGU boilers produce steam in order to generate power. While ICI boilers do in some cases generate steam for electricity production, ICI boilers differ from EGUs in size, steam application, design, and emissions. Most commercial and institutional boilers are small, with an average capacity of 17 MMBtu/hour (Table 1-1). Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. The average size of a coal-fired EGU boiler in the U.S. is over 200 MW or over 2,000 MMBtu/hr.

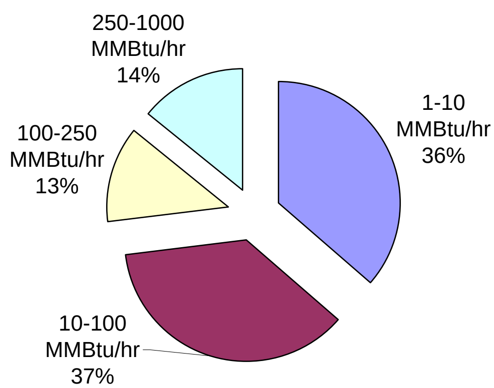
All coal-fired EGUs in the United States use control devices to reduce PM emissions. Additionally, many of the EGU boilers are required to use controls for SO_2 and NOx emissions, depending on site-specific factors such as the properties of the fuel burned, when the power plant was built, and the area where the power plant is located.

According to 1999 EPA Information Collection Request (ICR) responses from coal-fired EGUs, 77.4 percent of EGUs had PM post-combustion control only, 18.6 percent had both PM and SO_2 controls, 2.5 percent had PM and NOx controls, and 1.3 percent had all three post-combustion control devices [Kilgroe *et al.*, 2001]. Information from 2004 indicated that the fractions of total capacity of large coal-fired EGUs that have flue gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NOx controls were 38 percent and 37 percent, respectively [NESCAUM, 2005]. Since the 1999 ICR survey, additional NOx and SO_2 controls have been added at a rapid pace to coal-fired EGUs. It is presently not clear how

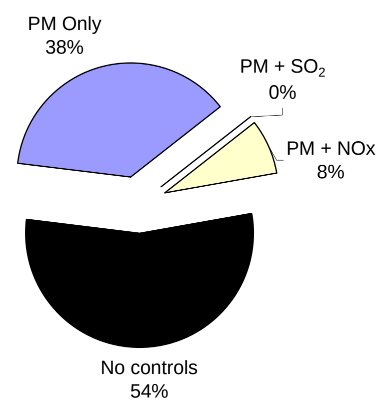
the implementation of NOx and SO_2 control technologies for EGUs would evolve as a consequence of the recent vacatur of Clean Air Interstate Rule (CAIR) by the U.S. D.C. Circuit.

In contrast to EGUs, ICI boilers are substantially less likely to have air pollution control devices. A study of industrial boilers and process heaters [USEPA, 2004] that looked at 22,117 industrial boilers and process heaters, which burned natural gas, distillate oil, residual oil, and coal, found that 88 percent had no air pollution control equipment.

A preliminary survey was undertaken as part of this study to evaluate the extent to which various emission controls were currently being applied to ICI boilers in the Northeast. These data were acquired from State Title V permits for solid-fueled (coal and wood) boilers as well as additional information from state personnel. The survey collected data in four states: Massachusetts, Vermont, New Hampshire, and New York. The data set was composed of 64 boilers – 47 wood-fired and 17 coal-fired. *Figure 1-5* illustrates the distribution of boiler capacity (by size) and the air pollution control devices (APCDs) in this data set. The full data set is summarized in Appendix A. As can be seen in *Figure 1-5(b)*, more than half of the units had no controls, about one-third had controls only for PM, and very few units had controls for NOx. There were no units with SO_2 controls, although some of the PM controls were wet venturi scrubbers, which might have a limited impact on SO_2 emissions.



(a) Distribution of capacity



(b) Distribution of APCDs

Figure 1-5. Solid-fuel boiler information from four northeast states, based on Title V permit information

There are several factors that directly or indirectly affect the reasons for the discrepancy in APCD deployment between EGU and ICI boilers. Technical and operational as well as business, economic, and regulatory factors impose different constraints and provide different opportunities for the applicability of APCDs for these two categories of boilers. The following discussion summarizes some of the important technical and operational issues.

Large, base-loaded EGUs operate mainly near maximum capacity or steam production. Industrial boilers typically do not run at maximum capacity, although this varies from one industry to another [EEA, 2005]. EGUs produce steam for electricity generation, while ICIs may produce steam for a variety of applications. The type of manufacturing is often more important

in determining boiler operation, or duty cycle (load vs. time) than manufacturing demand in general.

ICI boilers generate steam for processing operations for paper, chemical, refinery, and primary metals industries. Commercial boilers produce steam for a variety of processes, while institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities.

Another difference between EGU and ICI boilers is fuel diversity. EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), while ICI boilers tend to be designed for and use a more diverse mix of fuels (e.g., fuel by-products, waste, wood) in addition to the three conventional fuels above.

These differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of APCD applicability. Examples that directly affect APCD choice and applicability include equipment such as economizers or air preheaters, which affect the temperature of the flue gas at the stack. The differentiation in fuel usage also leads to different design parameters for emissions controls. For example, the iron and steel industry generates blast furnace gas or coke-oven gas, which is used in boilers, resulting in sulfur emissions. Pulp and paper boilers may use wood waste as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category.

These factors relate directly to APCD equipment choices and applicability. The following examples should help explain some of these impacts.

- Fuel quality – different fuels have different emission characteristics. SO_2, PM, and NOx emissions from coal fired boilers are different from those burning natural gas, oil, or wood waste. Some APCD technologies are not very sensitive to fuel quality variations (e.g., an electrostatic precipitator (ESP) may accommodate different levels of PM concentration, although the type and size of particles and gas temperatures will have an impact). However, others can be directly affected by changes in fuel quality and the resulting changes in pollutant concentrations in the flue gas to be treated (e.g., SO_2 and NOx controls that utilize reagents such as scrubbers for SO_2 and SCR/SNCR for NOx).
- Duty cycle – significant variation or cycling of boiler load requires APCD controls capable of accommodating such variations. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – the use of equipment such as economizers or air preheaters has direct impact on the resulting flue gas temperature. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers (wet and dry), and SCR /SNCR that are widely used in EGUs may or may not be applicable for some ICI boilers in such cases.

1.3.4 Control Technology Overview

A variety of emission control technologies are employed to reduce emissions of NOx, SO_2, and primary PM emissions. Technical details of control technologies for NOx, SO_2, and PM are discussed in Chapters Two, Three, and Four, respectively. Pollutant emission controls are generally divided into three major types given in the following list.

- *Pre-combustion Controls*. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls*. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Data on costs of pollution control equipment taken from the literature are reviewed in the individual technology chapters. In Chapter Five, an existing model for the estimation of air pollution control equipment costs for coal-fired EGUs (CUECost) is applied to ICI boilers burning different fuels (coal, oil, wood) with appropriate caveats and assumptions to provide reasonable and approximate control costs for ICI boilers.

1.4 Chapter 1 References

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2 NOx CONTROL TECHNOLOGIES

2.1 Introduction

This brief introduction applies to chapters Two, Three, and Four, which discuss control technology options for ICI boilers for NOx, SO_2, and PM, respectively. However, these chapters are not intended to provide detailed descriptions of the many available technologies for each pollutant. Significant literature is available for that purpose; in the context of this report, these chapters are intended to provide the reader with a general understanding of concepts, performance, applicability, and costs of the main technologies available. Further, in recognition of the concern with climate change, a brief discussion of energy consumption (parasitic power) associated with major technologies is included.

Specifically with respect to the deployment and applicability of air pollution controls, comparisons between ICI boilers and EGUs are relevant because of the more widespread application of pollution control equipment in the EGU sector. This was discussed in some detail in Chapter One. In addition, a few considerations specific to certain technologies and strategies are discussed, as appropriate.

2.1.1 ICI versus EGU Boilers

In general, the greater proliferation of air pollution control technologies in the EGU sector, as opposed to the industrial sector, seems to be driven by three dominant, differentiating factors.

- Size difference and associated emissions between the two: Because EGUs are much larger than ICI boilers, they have been targeted for environmental regulatory controls more heavily over the years.
- Technology costs: While not universally true, ICI boilers often have constraints due to their smaller sizes, diversity of plant layouts, and urban settings, all of which can have a negative impact on the costs of applying some of the control technologies. Conversely, and equally important, opportunities for lower-cost applications to ICI boilers do exist as a result of the smaller sizes, such as in the ability to have systems pre-fabricated and ready to erect onsite, as opposed to on-site construction requirements often needed with larger systems for EGUs.
- Cost recovery: The two sectors are significantly different from a fundamental business view, with EGUs being regulated entities, as opposed to openly competitive markets that exist within the ICI boiler population. This is important in that it affects how business decisions are made in the two sectors, how capital equipment purchases are funded, and also how ICI plants are designed and operated.

2.1.2 Control Technologies' Impact on Efficiency and CO_2 Emissions

Air pollution control technologies and strategies can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative and it is a function of the type of technology, as well as fuel choices.

An extreme example of this is the control of SO_2 from a coal-fired unit by two significantly different approaches: in one case, the use of an energy–intensive FGD "scrubber" penalizes the efficiency of such unit by up to 2 percent, resulting in a corresponding increase in CO_2 emissions; a very different and contrasting case, in which the unit chooses to reduce its SO_2 generation by switching from coal to natural gas, yields a corresponding and substantial decrease in its CO_2 emissions. Similarly, an efficient Low-NOx Burner (LNB) may replace an older burner and increase unit efficiency, while reducing NOx emissions, whereas a SNCR or SCR also reduces NOx, but will have some inherent parasitic power requirement that will have a negative impact on overall efficiency (and emissions of CO_2).

These chapters primarily address control technology options, as opposed to fuel switching strategies, except for SO_2. Switching from high-sulfur oil to low-sulfur oil is also discussed in Chapter 3. CO_2 impacts are well established as a function of the carbon content of fuels. The same applies in the case of renewable, carbon-based fuels (biomass). However, with control technologies, the impacts can vary widely among technologies for the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. wet and dry scrubbers for SO_2).

In general, efficiency impacts from application of air pollution control technologies can be divided into two major general areas:

- Direct impact (positive or negative) on the combustion process itself (e.g., changes in concentrations of O_2 or CO and in the amount of unburned carbon (UBC) in ash)
- Parasitic power associated with the particular technology or its components (e.g., increased gas pressure loss, power requirements for pumps/fans)

This parasitic power is given here in terms of electric power (kW) per flue gas flow rate (acfm) or kW/1000 acfm. These units are appropriate for several reasons:

- Most ICI boilers do not produce electricity, hence, size is more universally characterized by a parameter other than electrical generation (e.g., flow rate);
- Most control technology suppliers rank their equipment size in terms of gas flow rate as this is the dominant parameter for gas handling equipment sizing;
- If the objective is to "correlate" this parasitic power loss to an equivalent CO_2 impact, it can be done simply by knowing the size (acfm) of the technology application and the CO_2 emission profile of the equivalent kW generation (or savings) to offset the parasitic power loss.

2.2 Discussion of NOx Control Technologies

2.2.1 NOx Formation

The formation of NOx is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form NOx. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NOx emissions.

2.2.2 NOx Reduction

As a result of complex interactions in the formation of NOx, a variety of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NOx emission control is to divide them into two major categories: (1) those that minimize the formation of NOx itself during the combustion process (e.g., smaller quantities of NOx are formed); and (2) those that reduce the amount of NOx after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach under the "umbrella" of combustion modifications whereas technologies in the second category are termed post-combustion controls. Within each of these two categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NOx control than the application of a stand-alone technology.

2.2.3 Other Benefits of NOx Control Technologies

Some NOx control technologies have shown the potential to promote the capture of mercury (Hg) from the flue gas. Examples include combustion modification technologies (e.g., Low-NOx Burners and Overfire Air – though potentially with higher levels of unburned carbon) and post-combustion technologies (SCR – through the oxidation of mercury, making it more soluble and amenable to capture in a downstream process such as a scrubber for SO_2). This suggests that strategic and economic analyses for NOx controls need to also consider the potential impacts on mercury removal.

2.3 Summary of NOx Control Technologies

2.3.1 Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as LNBs, Overfire Air (OFA) or reburn (most often done with natural gas and called Gas Reburn - GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to reductions in NOx emissions of 5 to 15 percent or even higher in cases where a unit was originally badly “de-tuned.” It is important to remember that optimization results are truly a function of the “pre-optimization” condition of the power plant or unit (just as the improvement in an automobile from a tune-up depends on how badly it was running prior to it), and as such have limited opportunity for substantial emission reductions.

Development of “intelligent controls” – software-based systems that “learn” to operate a unit and then maintain its performance during normal operation, can also go a long way towards keeping plants well tuned, as they gain acceptance and become common features in combustion control systems.

2.3.2 Low-NOx Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NOx during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as “fuel or air staging”).

Figure 2-1. Low-NOx burner [TODD Dynaswirl-LN™]

Figure 2-1 shows a gas/oil Low-NOx burner. These technologies are prevalent in the electric power industry as well as in ICI boilers at present and increasingly used by ICIs, even at small sizes (less than 10 MMBtu/hr). Competing manufacturers have proprietary designs, geared towards application for different fuels and boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NOx reductions of 30 to 65 percent from uncontrolled baseline levels. Again, the type of boiler and the type of fuel will influence the actual emission reduction achieved.

Particularly for gas-fired applications, as in the majority of ICI boilers, advanced Low-NOx Burners, often referred to as ultra Low-NOx Burners (ULNBs), are commercially offered by several companies. Ultra Low-NOx Burners are capable of achieving NOx emission levels on the order of single digits in ppm. As with all technologies, "pushing the envelope" on emission levels requires increasingly more careful suitability analyses as well as a good understanding of operational constraints. Conversely, the advent of these very low-emission burners (less than 10 ppm NOx), allows units to achieve very low emission rates at costs well below post-combustion alternatives like SCR.

All combustion modification approaches face a common challenge of striking a balance between NOx reduction and decrease in fuel efficiency. The concern is exemplified by typically higher CO and/or carbon levels in the fly ash, which reflect lower efficiency and also the contamination of the fly ash itself, possibly making it unsuitable for reutilization such as in concrete manufacturing. This is a bigger concern for large EGUs than for ICI boilers due to the much larger quantities of ash produced and the associated costs of disposal.

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss). Low-NOx Burners are applicable to most ICI boiler types, excluding stoker types and Fluidized Bed Combustion units (FBCs).

2.3.3 Reburn

Reburn, while generically included in the "Combustion Modification" category, is different from the other technologies in this group (LNBs/OFA) in that it "destroys" (or chemically reduces) NOx shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, however, natural gas is the most common) into the boiler above the main burner region. A portion of the heat input from the primary fuel is replaced by the reburn fuel. Subsequently, this "fuel-rich" environment reacts with and destroys the NOx formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as popular as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. *Figure 2-2* shows a typical reburn system applied to a stoker boiler.

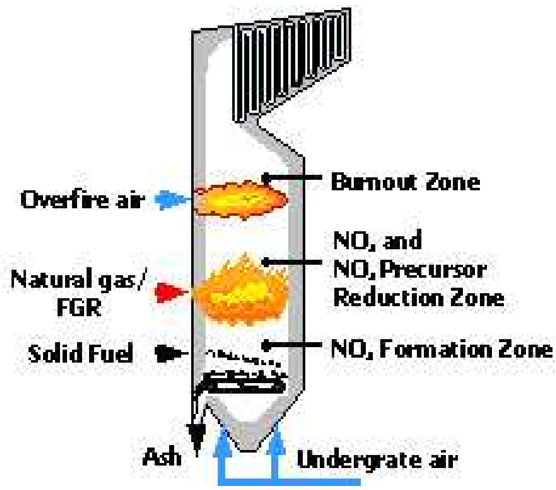

Figure 2-2. Gas reburn applied to a stoker boiler [www.gastechnology.org]

Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel, are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with a particular type of boiler – "Cyclone," – for which the previously mentioned technologies are not particularly well suited. However, this technology has been used only in large EGUs and is not a typical option for ICI boilers. Cyclone boilers are inherently high NOx emitters and are not an attractive option for new or retrofit units with increasingly lower NOx emission limits requirements.

Reburn performance has been shown to range from 30 to 60 percent reduction in NOx emissions, depending on such factors as reburn fuel type and quantity, initial NOx levels, boiler design, etc. Similar to the other combustion modification options, reburn can affect efficiency and fly-ash quality. As such, it requires the same optimum balance between NOx reduction and avoidance of negative impacts. On the other hand, reburn can be thought of as a "dial-in" NOx technology in that NOx reductions are, to a degree, a function of the amount of reburn fuel.

Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Reburn using coal or oil as the reburn fuel does not seem like a very attractive option for ICI boilers for technical reasons (boiler size, residence times), as well as the wider availability of similar performance options simpler to implement, such as LNBs. Gas reburn, while easier to implement, often has a prohibitive operating cost if, for example, natural gas is partially substituted for a less expensive primary fuel. Reburn is therefore an option for larger watertube-type boilers, including stokers, but require appropriate technical and economic analyses to determine suitability. Gas reburn has an impact on CO_2 emissions that is proportional to the type and quantity of fuels displaced (gas vs. coal or oil).

2.3.4 Post-Combustion Controls

Conventional, commercial post-combustion NOx controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NOx produced in the boiler to convert the NOx to harmless nitrogen and water. SNCR accomplishes this at higher

temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NOx. As noted below, SCR technology is capable of achieving much larger reductions in NOx emissions, higher than 90 percent, compared to the 30 to 60 percent reductions achievable by SNCR. *Figure 2-3* and *Figure 2-4* depict views of these two systems.

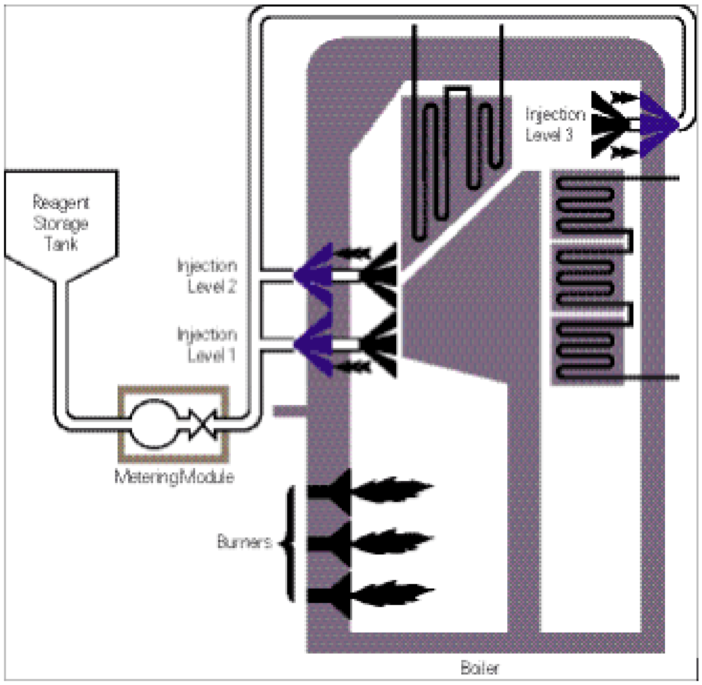

Figure 2-3. SNCR system schematic [FuelTech]

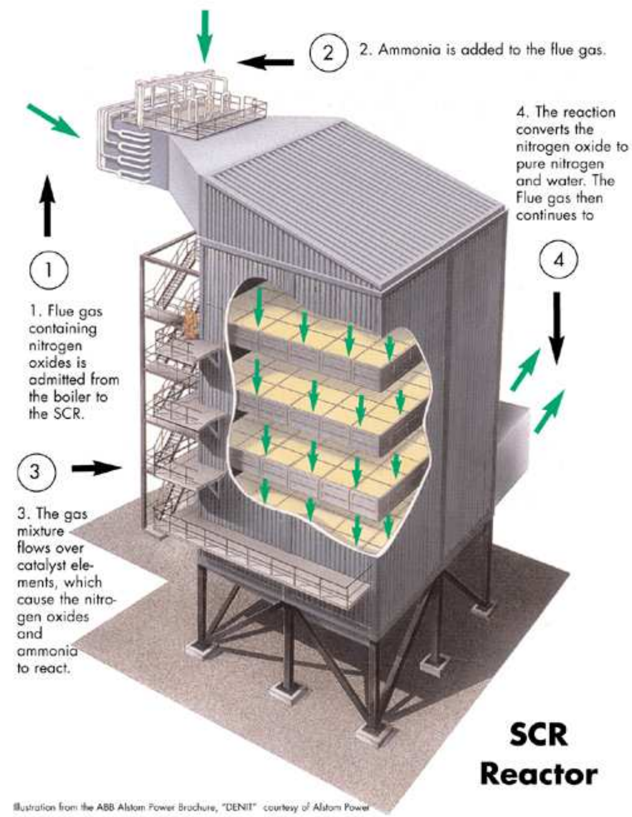

Figure 2-4. 3-D schematic of an SCR system [Alstom Power]

While the difference between the SNCR and SCR may seem minor, it yields significant differences in performance and costs. In the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the reaction vessel, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NOx); and finally, has lower NOx reduction capability (typically 30 to 50 percent, with some units achieving reductions in the 60 percent range). SCR, on the other hand, is capital intensive, but offers lower reagent costs and the opportunity for very high NOx reductions (90 percent or higher).

Costs are driven primarily by the consumption of the chemical reagent – usually (but not necessarily) urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NOx level and the desired percent reduction. It is also important to consider possible contamination of fly ash (in the case of coal firing) by ammonia making it potentially unable to be sold. This is, again, a bigger issue for larger EGU plants than for ICI boilers due to the size and quantities involved; as already stated, ICIs burning solid fuel do not typically sell their fly ash.

2.3.4.1 RSCR

Commonly, EGU boilers utilize SCR systems to reduce NOx emissions. However, a conventional SCR may not be cost-effective to retrofit into smaller units like ICI boilers because of the extensive modifications required to accommodate the unit. For some applications, the SCR may be located downstream of the particulate control equipment, where the flue gas temperature is much lower than the range of 650-750°F required for a conventional SCR (Toupin, 2007). These conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

If it is necessary to compensate for the reduction of flue gas temperatures, a regenerative selective catalytic reduction (RSCR™) system allows the efficient use of an SCR downstream of a particulate control device. The primary application of an RSCR system is the reduction of NOx emissions where the flue gas is typically at 300-400°F (Toupin, 2007). *Figure 2-5* illustrates the schematic and the actual RSCR system. *Figure 2-6* shows a block of ceramic heat exchanger.

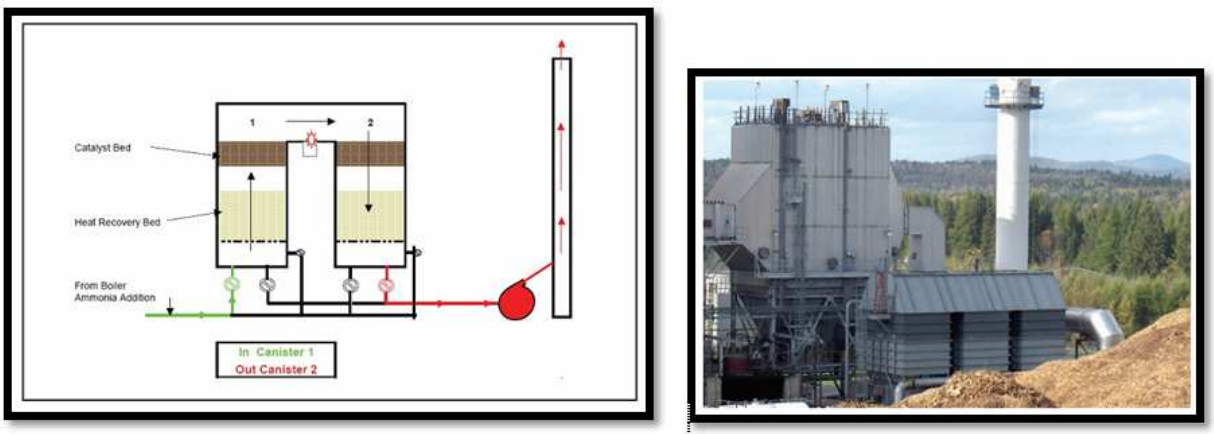

Figure 2-5. Schematic and actual RSCR [Toupin, 2007]

A direct-contact regenerative heater technology (i.e., burner), coupled with cycling beds of ceramic heat exchangers, is used to transfer heat to the flue gas. Additionally, some oxidation of CO to CO_2 in the flue gas occurs. The NOx reduction portion of the RSCR takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia can be used.

Figure 2-5 (left side) shows the working principles of the RSCR. Essentially, the flue gas in the space between the two canisters (called the retention chamber) is heated by the burner to make up for heat loss through the walls of the canisters and inefficiency in the ceramic heat transfer modules. This raises the temperature in the retention chamber by about 10-15ºF. The gas flows into the second canister, through the catalyst, and passes through the second ceramic module, which absorbs heat from the hot flue gas. Once this cycle is completed, the flow reverses, so that the second canister (which was just heated) becomes the inlet canister and the first canister becomes the outlet canister. The cycling between canisters accomplishes a similar function to the continuously rotating heating elements of a conventional regenerative air/gas heater.

Other components of the RSCR include the ductwork, fans, and the ammonia delivery system. Ductwork must be adequately sized to provide sufficient distance for ammonia mixing

and to minimize pressure drop. For the ceramic heat exchanger, factors that need to be taken into consideration during the design process are gas-side pressure drop, thermal efficiency, and cost. A large bed face area reduces the pressure drop and operating cost but increases capital cost. The ammonia delivery system consists of ammonia pumps, storage tanks, interconnecting piping, and a control system. The pump typically does not exceed one horsepower and often a redundant pump is provided to assure continuity in system operation [Toupin, 2007].

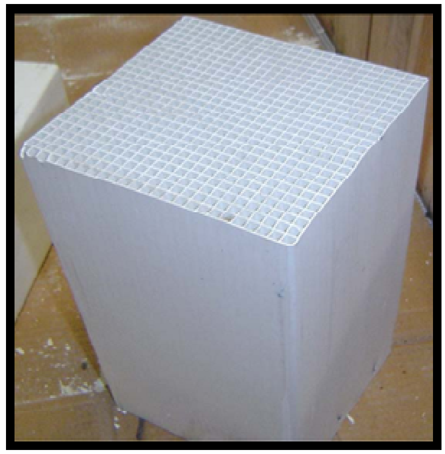

Figure 2-6. Block of monolith ceramic heat exchanger [Toupin, 2007]

The RSCR combines a regenerative thermal oxidizer (RTO) (e.g., retention chamber burner) with SCR technology. This ability to control flue gas temperatures allows for high NOx reduction under varying temperature conditions. *Table 2-1* shows the expected reduction in NOx and CO emissions [BPEI, 2006]. This study indicated that the RSCR is able to reduce NOx by 60 to 75 percent and CO by about 50 percent.

Table 2-1. CO and NOx reduction using RSCR [Source: BPEI 2006]

	Typical Stoker Design	**CO and NOx Reductions from Baseline**
Steam Flow lbs/hr x 10^3	100 – 500	
Steam Press, psi	600 – 900	
Steam Temp., °F	955 – 1000	
Unburned Combustibles Boiler Efficiency Loss (%)	1.0 – 1.5	
Furnace Retention sec.(1)	3.0	
Grate Heat Release Btu/hr-ft	850,000 maximum	
Emissions:		
CO lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.30 (122 – 370)	Base
CO **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.05 – 0.15 (61 – 185)	(-50%)
NOx lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.15 – 0.25 (112 – 186)	Base
NOx **w/SNCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.17 (75 – 130)	(-30 to 40%)
NOx **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.06 – 0.075 (45 – 56)	(-60 to 75%)

Additionally, the heat exchanger part of the RSCR has a thermal efficiency of about 95 percent, which translates to fuel savings. Traditional technologies that utilize Ljungstrom or plate type heat exchangers for heat recovery and duct burners to reach the catalyst operating temperature are typically in the range of 70 to 75 percent thermal efficiency.

An analysis performed by BPEI on a typical 25 MW plant with a 75 percent reduction in NOx shows a cost effectiveness of $4,514 per ton of NOx removed. The cost breakdown is tabulated below in *Table 2-2*.

Table 2-2. RSCR cost efficiency [BPEI, 2008]

Plant Overview:	
Plant Gross MW	25
GROSS HEAT INPUT, MMBTU/HR	321
TYPICAL UNCONTROLLED NOx, LB/MMBTU	0.25
TYPICAL CONTROLLED NOx, LB/MMBTU	0.065
NOx REMOVED, TONS/YEAR	249.4
RSCR Cost:	
AMMONIA COST, $/TON NOx	$ 419
NATURAL GAS, $/ton NOx	$ 404
POWER COST, $/TON NOx	$ 589
CATALYST COST, $/TON	$ 555
CAPITAL COST, $/TON	$ 2,546
TOTAL COST PER TON NOx REMOVED	$ 4,514

Two RSCR installations (15 and 50MW) are currently in operation in the Northeast. The 15 MW plant uses whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of the two installations was to qualify for the Massachusetts Renewable Energy Credits (RECs). The state requirement for qualifying for RECs imposed a NOx level of 0.075 lb/MMBtu or less on a quarterly average basis.

2.3.5 Technology Combinations

In theory, most of the technologies described above can be used together. However, NOx reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NOx levels entering the SCR/SNCR system. Another combination offered commercially is the hybrid SNCR/SCR concept, which uses the excess ammonia (ammonia “slip”) of the SNCR to promote additional NOx reduction in a downstream SCR catalyst.

2.4 Applicability to ICI Boilers

The NOx control technologies previously described are commercially available and are used extensively in EGUs, but most are also applicable to ICI boilers. Because conventional fuels (e.g., coal, oil, gas) as well as alternative fuels (e.g., wood, petroleum coke, process off-gases) emit NOx, these technologies are applicable to most boilers using various fuels. With the exception of FBC and Stoker boilers, LNBs are available and widely used for most combinations of boiler types and fuels. OFA and reburn as well as SNCR and SCR technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility. As already stated, these include available space, residence times and gas temperatures. Conversely, other than firetube type boilers, these technologies are potential candidates for the other boiler types including stokers and FBCs. Finally, the RSCR may offer advantages for applications where low flue gas temperatures are present and a conventional SCR may be more costly to implement.

2.5 Efficiency Impacts

The NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the noted exception for reburn when displacing coal or oil with natural gas. This is because combustion modification technologies do not impose any significant parasitic energy consumption (auxiliary power). Note that combustion modification technologies can affect the resulting combustion conditions in addition to the desired reduction in NOx emissions. These impacts are reflected in varying temperatures, oxygen levels, and CO/UBC, all of which affect combustion efficiency as discussed previously. However, we do not attempt to quantify these impacts. The overriding assumption is that these NOx control technologies, once deployed, are optimized such that the resulting NOx emissions are achieved without compromising the above parameters (or at least their combined effects).

With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy impact on the host boiler. The losses attributable to these technologies include the following:

- For SNCR
  - compressor power (air atomization/mixing)
  - steam (if steam atomization/mixing)
  - dry gas loss (air injection into furnace)
  - water evaporation loss
- For SCR
  - compressor
  - reactor pressure loss
  - steam (sootblowing)

Table 2-3 summarizes the key parameters for major NOx control technologies.

Table 2-3. Summary of NOx control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impacts (kW/1000 acfm)	Comments
LNB	All except Stokers, FBC	30 – 60 (<10ppm possible on gas)	NA	Assumed not to have negative impact on $CO/UBC/O_2$
OFA	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
Reburn	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
SNCR	All except firetube (Must have adequate temperature window)	30 - 70	1 - 2	Compressor/vaporization losses
SCR	All (Most likely for larger coal units where LNBs cannot reach very low NOx levels)	60 - 90	0.5 – 1 (gas) 2 - 4 (oil/coal)	Pressure loss/steam

2.6 NOx Control Costs

The following tables summarize published NOx control costs for ICI boilers reported in the literature [US EPA, 1996; NESCAUM, 2000; Khan, 2003; US EPA, 2003; MACTEC, 2005; Whiteman, 2006]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of NOx removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some operating costs. Costs of reagents and fuels (e.g., ammonia, natural gas) and consumables (e.g., SCR catalyst) change with time, but not always at the general rate of inflation. Some of these costs have increased at rates higher than the general rate of inflation. Thus, cost effectiveness values (or operating costs) from before 2005 have not been reported.

Table 2-4 summarizes the published NOx control costs for combustion modification technologies. The cost of the installation of low-NOx combustion technology depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity (*Figure 2-7*). Smaller boilers (10 to 50 MMBtu/hr) are often firetube or packaged watertube, whereas larger oil and gas boilers are more likely to be field-erected watertube boilers. Coal-fired boilers can be stokers, pulverized coal (PC), or cyclones. Combustion modification technologies therefore need to be evaluated on a case-by-case basis, taking into account both the fuel and the design of the combustion system. For the substantial majority of the estimates for ICI boilers, capital costs are in the range of $1,000 to $6,000 per MMBtu/hr. Cost effectiveness values, where available, are generally in the range of $1,000 to $7,000 per ton of NOx removed.

Table 2-4. NOx control costs for combustion modifications applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
Overfire Air	15-30	Coal	500	$2,682	1996		1
Fuel-Lean GR	35%	Coal	350	$1,302	1999		2
Gas Reburn	55%	Coal	500	$2,604	1999		2
LNB	25%	Coal	350	$6,378	1999		2
LNB	36.0%	Coal	350	$6,378	1999		2
LNB	50%	Coal	500	$8,464	1996		1
LNB	51%	Coal	100	$9,287	1999		6
LNB	51%	Coal	250	$7,055	1999		6
LNB	51%	Coal	1000	$4,654	1999		6
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,383	3
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,988	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$2,636	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$3,101	3
LNB	40%	Pulv. Coal	250	$346-$3,610	2005	$749-$3,393	3
LNB	45.0%	Resid. Oil	250-FT	$5,088	2005	$6,361-$7,483	3
LNB	50%	Resid. Oil	250-WT	$5,088	2005	$4,691-$5,519	3
LNB	40%	Resid. Oil	250	$346-$5,088	2005?	$1,505-$6,813	3
LNB	45%	Resid. Oil	10	$7,617	1996		1
LNB	45%	Resid. Oil	50	$3,021	1996		1
LNB	45%	Resid. Oil	150	$1,563	1996		1
LNB	45%	Dist. Oil	10	$7,617	1996		1
LNB	45%	Dist. Oil	50	$3,021	1996		1
LNB	45%	Dist. Oil	150	$1,563	1996		1
LNB	25%	Gas	350	$6,378	1999		2
LNB	40%-55%	Gas	10	$7,617	1996		1
LNB	40%-55%	Gas	50	$3,021	1996		1
LNB	40%-55%	Gas	150	$1,563	1996		1
LNB+FGR	50%	Pulv. Coal	250	$930-6,629	2005	$1,482-$3,582	3
LNB+FGR	72%	Pulv. Coal	250	$930-6,629	2005	$1,029-$2,488	3
LNB+FGR	50%	Resid. Oil	250	$930-6,629	2005	$2,977-$7,197	3
LNB+FGR	72%	Resid. Oil	250	$930-6,629	2005	$2,068-$4,998	3
LNB+OFA	51%-65%	Coal	100	$9,287	1999		6
LNB+OFA	51%-65%	Coal	250	$7,055	1999		6
LNB+OFA	51%-65%	Coal	1000	$4,654	1999		6
LNB+OFA	30%-50%	Oil	100	$3,258	1999		6
LNB+OFA	30%-50%	Oil	250	$2,474	1999		6
LNB+OFA	30%-60%	Oil	1000	$1,633	1999		6
LNB+OFA	60%	Gas	100	$3,258	1999		6
LNB+OFA	60%	Gas	250	$2,474	1999		6
LNB+OFA	60%	Gas	1000	$1,633	1999		6

Table 2-4 [continued]

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
ULNB	46%	Pulv. Coal	250	$1,364	2005	$1,876	3
ULNB	63%	Pulv. Coal	250	$1,364	2005	$933	3
ULNB	72%	Pulv. Coal	250	$1,364	2005	$619	3
ULNB	75%	Pulv. Coal	250	$1,364	2005	$784	3
ULNB	85%	Pulv. Coal	250	$1,364	2005	$692	3
ULNB	75%	Resid. Oil	250	$1,364	2005	1575	3
ULNB	85%	Resid. Oil	250	$1,364	2005	1390	3
ULNB	80%	Dist. Oil	24.5	$8,619	2005	17954	3
ULNB	80%	Dist. Oil	70	$2,280	2005	5756	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4751	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4564	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
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5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

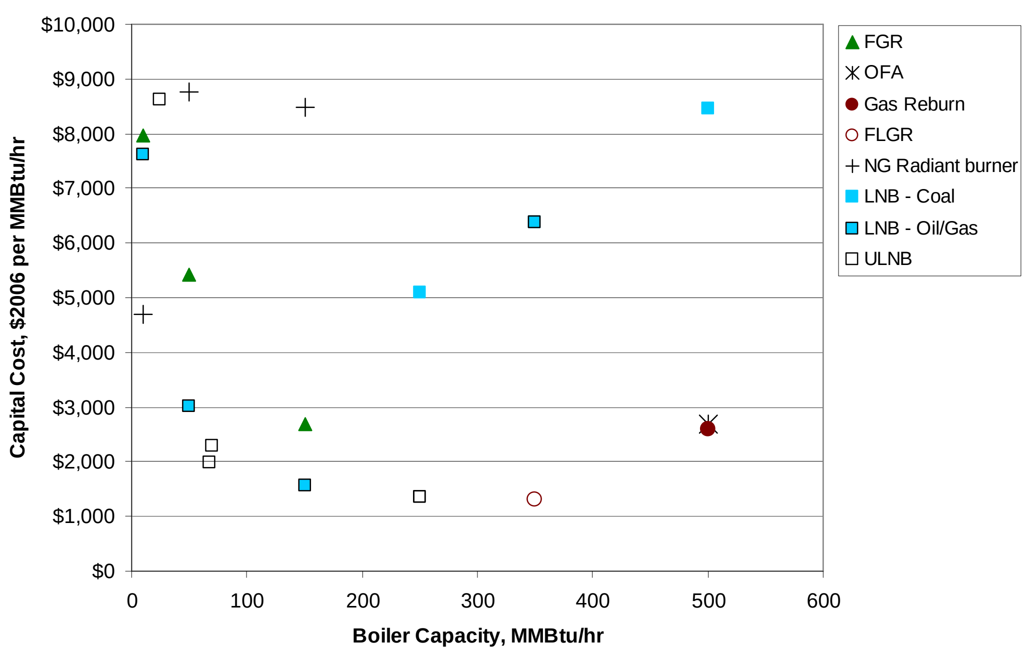

Figure 2-7. Capital cost for NOx control for combustion modification applied to ICI boilers as a function of boiler capacity

Table 2-5. NOx control costs for SNCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SNCR	30%-70%	Coal	500	$2,044	1996		1
SNCR	40%	Coal	100	$6,717	1999		6
SNCR	40%	Coal	250	$5,102	1999		6
SNCR	40%	Coal	1000	$3,366	1999		6
SNCR	30%-70%	Resid. Oil	50	$4,297	1996		1
SNCR	30%-70%	Resid. Oil	150	$4,297	1996		1
SNCR	35%		350	$2,862	1999		2
SNCR			21	$17,101	2006	$3,718	4
SNCR			120	$6,377	2006	$2,231	4
SNCR			240	$4,493	2006	$1,821	4
SNCR			387	$2,899	2006	$1,564	4
SNCR			543	$2,319	2006	$1,538	4
SNCR			844	$1,449	2006	$1,346	4
SNCR	40%	Oil	100	$5,205	1999		6
SNCR	40%	Oil	250	$3,954	1999		6
SNCR	40%	Oil	1000	$2,608	1999		6
SNCR	30%-70%	Dist. Oil	50	$4,297	1996		1
SNCR	30%-60%	Natural Gas	50	$4,297	1996		1
SNCR	40%	Gas	100	$5,372	1999		6
SNCR	40%	Gas	250	$4,082	1999		6
SNCR	40%	Gas	1000	$2,693	1999		6
LNB+SNCR	50%-89%	Pulv. Coal	250	$2,064-6,829	2005	$1,409-$4,473	3
LNB+SNCR	50%-89%	Resid. Oil	250	$2,064-6,829	2005	$2,229-$7,909	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

Table 2-5 summarizes the published NOx control costs for SNCR applied to ICI boilers. As with combustion modifications, the capital cost of SNCR systems is sensitive to the type of combustion system. As long as the boiler has sufficient space for installation of injection lances and mixing of reagent and flue gas (at the appropriate temperature), the capital costs should not depend on the fuel burned. The relationship between capital cost and boiler capacity is shown in *Figure 2-8*. Except for the 1996 EPA estimates for gas and oil boilers, there is a pronounced effect of boiler capacity on capital cost. The graph shows that fuel type is probably secondary to boiler capacity, although there will be an indirect effect of fuel, because fuel type influences the design of the combustion system. The cost effectiveness for SNCR was given by ICAC [Whiteman, 2006] without regard to fuel type and by MACTEC [2005] for coal and residual oil.

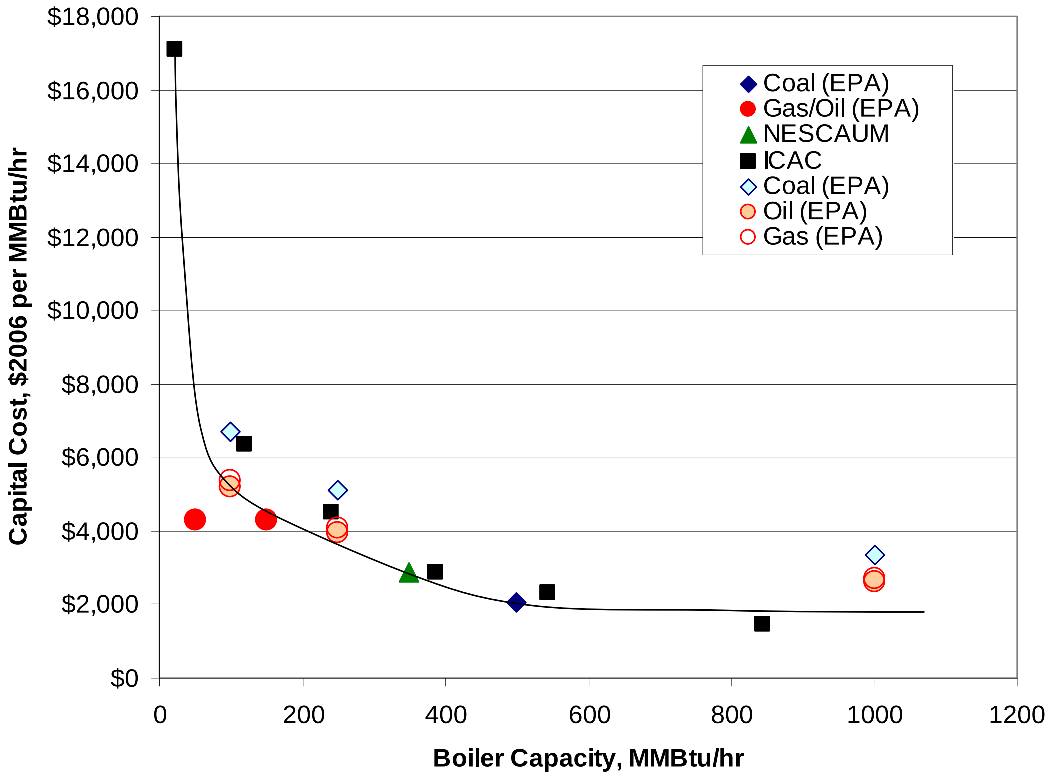

Figure 2-8. Capital cost for NOx control for SNCR applied to ICI boilers as a function of boiler capacity

Table 2-6 summarizes the published NOx control costs for SCR. The relationship between capital cost and boiler capacity is shown in *Figure 2-9*. The capital cost of SCR systems is sensitive to the type of fuel and to the level of NOx reduction desired, but not to the combustion system. The volume of catalyst required for an SCR installation depends on the level of desired NOx reduction and on the fuel. Coal-fired power plant applications are the most expensive, since the flue gas entering the SCR contains fly ash, which affects the design of the catalyst. The capital cost for a given fuel and boiler size can vary (see, for example, the variation in capital costs reported for coal application). When an SCR must be retrofit, the cost of the installation depends on the configuration of the specific system. Because the amount of

ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

Table 2-6. NOx control costs for SCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SCR	80%	Coal	*350*	$12,755-19,133	1999		2
SCR	80%-90%	Coal	500	$15,365-16,145	1996		1
SCR	70%-90%	Pulv. Coal	250	$1,666-13,881	2005	$2,233-$7,280	3
SCR	80%	Coal	100	$18,574	1999		6
SCR	80%	Coal	250	$14,110	1999		6
SCR	80%	Coal	1000	$9,309	1999		6
SCR	80%	Oil	100	$14,116	1999		6
SCR	80%	Oil	250	$10,723	1999		6
SCR	80%	Oil	1000	$7,075	1999		6
SCR	--	Oil	--	$5,102-7,653	1999		5
SCR	70%-90%	Resid. Oil	250	$1,666-13,881	2005	$4,363-$14,431	3
SCR	80%-90%	Resid. Oil	50	$8,359	1996		1
SCR	80%-90%	Resid. Oil	150	$4,909	1996		1
SCR	80%-90%	Dist.	50	$8,359	1996		1
SCR	80%-90%	Dist.	150	$4,909	1996		1
SCR	80%	Gas	100	$10,216	1999		6
SCR	80%	Gas	250	$7,760	1999		6
SCR	80%	Gas	1000	$5,120	1999		6
SCR	80%	Gas	100	$9,566	1999		2
SCR	80%	Gas	350	$7,015	1999		2
SCR	80%-90%	Natural Gas	50	$8,359	1996		1
SCR	80%-90%	Natural Gas	150	$4,909	1996		1
SCR	80%	Wood	350	$6,378-7,653	1999		2
SCR	74%	Wood	321	$1,978	2006	$4,514	7

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
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6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.
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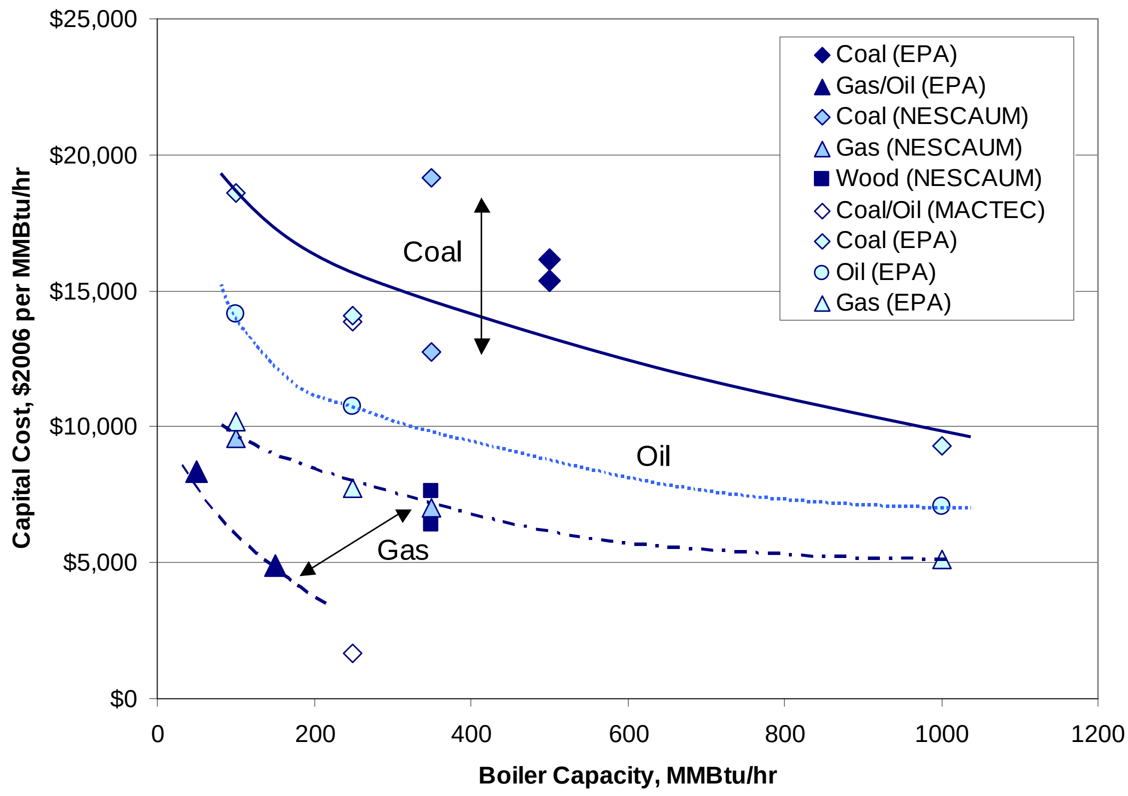

Figure 2-9. Capital cost for NOx control for SCR applied to ICI boilers as a function of boiler capacity

2.7 Chapter 2 References

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3 SO_2 CONTROL TECHNOLOGIES

3.1 SO_2 Formation

SO_2 is an undesirable byproduct of the combustion of sulfur-containing fossil fuels. SO_2, like NOx, is a precursor to ambient fine particles: Thirty to 50 percent of ambient fine PM mass in the eastern U.S. is attributable to sulfate derived from SO_2. SO_2 is a significant contributor to wet and dry acid deposition on various ecosystems (lakes, streams, soils, and forests). Various coals in the U.S. can have 1 to 3 percent (by mass) sulfur; residual oil (No. 6 oil) can have sulfur contents of 2 percent and higher. Distillate oils are generally lower in sulfur content (less than 0.5 percent by mass). Natural gas has essentially zero sulfur content. However, unlike nitrogen in coal or oil, essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics). This means that the relationship between sulfur content in the fuel and SO_2 emissions is much more direct and linear than that between fuel nitrogen and NOx emissions, and as such, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal or from higher-sulfur oils to lower-sulfur oils) are directly proportional to the difference in sulfur contents of fuels.

Another important difference is that this relationship is, for all practical purposes, independent of the type of boiler technology. Two exceptions to this include the high–alkaline nature of ash in some sub bituminous coals, which causes a portion of the sulfur in the coal to react and form various sulfate salts (mostly calcium sulfate); another is the combustion of coal in fluidized bed combustion (FBC) boilers where the lower temperatures of combustion and the use of alkaline material (e.g., limestone) in the "bed" promote the reaction of SO_2 with calcium to form sulfate, thereby reducing the net emissions of SO_2. In practical terms, this means that most solid- and liquid-fuel-fired systems produce SO_2 emissions proportional to their sulfur content, whereas natural gas combustion produces essentially no SO_2.

Additionally, despite the much smaller quantities of SO_3 formed in comparison to SO_2, as noted above, SO_3 presents both operational and environmental challenges. Operationally, SO_3 is a concern because if the temperature of the back-end flue gas handling equipment (e.g., ducts, particulate control devices, scrubbers) falls below the acid dew point, corrosion and material deterioration can result. From an environmental perspective, nucleation and condensation of ultra-fine sulfuric acid particles formed from the SO_3 present in the flue gas can contribute to the primary emissions of fine PM from the stack into the atmosphere.

3.2 SO_2 Reduction

As a result of the relationship between fuel sulfur content and SO_2, SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. This is accomplished by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers" and are usually

described in terms of the process conditions (wet vs. dry), methods for gas-sorbent contact (e.g., absorber vessel vs. duct for dry sorbent injection), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction, and the use of enhancing additives. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability to ICI boilers, and data on performance and cost. For a more detailed description of FGD technologies, see Srivastava [2000].

As noted earlier, SO_2 control strategies can also include fuel switching (from high-sulfur coal to low-sulfur coal or from high-sulfur oil to low-sulfur oil/natural gas). While not considered a "technology," switching from a higher-sulfur fuel to a lower-sulfur one requires considerable cost and operational analysis. Major issues include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

3.3 Other FGD Benefits

Significant attention has been given recently to the issue of mercury emissions from EGUs and ICI boilers. It is relevant to note that some FGD technologies have been shown to capture mercury from the flue gas [Jones and Feeley, 2008] by absorbing the water-soluble oxidized forms of mercury from the flue gas. Both wet and dry SO_2 control processes have been and are being tested to determine their mercury capture potential. This suggests that strategic and economic analyses for SO_2 control technologies need to consider the potential side-benefit of mercury removal as well.

3.4 Summary of FGD Technologies

A brief overview of FGD technologies is provided here to give the reader a broad perspective on SO_2 controls.

3.4.1 Wet Processes

Wet FGD (WFGD) or "wet scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s [NESCAUM 2000]. They represent the predominant SO_2 control technology in use today with over 80 percent of the controlled EGUs capacity in the world and the U.S. [EPA 2000].

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield >90 percent SO_2 capture. Currently, advanced scrubber designs for EGUs have eliminated not only many of the early operational problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with the technology being capable of well over 95 percent SO_2 control [Dene *et al.*, 2008]. *Figure 3-1* provides a schematic view of a wet scrubber.

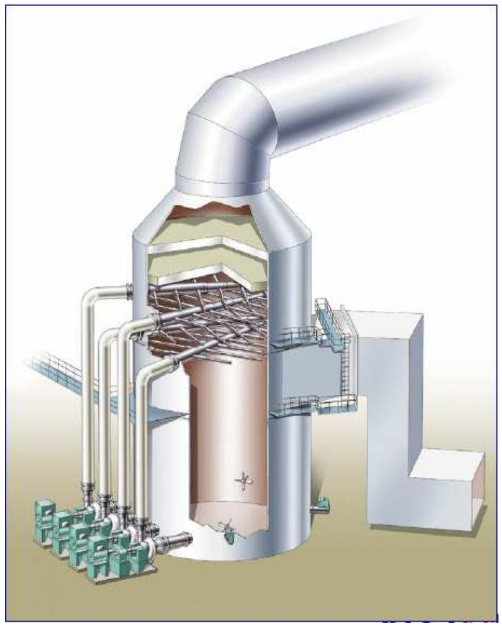

Figure 3-1. Schematic of a WFGD scrubber [Bozzuto, 2007]

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate, ammonia, and even seawater-based processes are all commercially available. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, and efficiency targets.

Technology costs have changed over time, as expected, reflecting changes in market conditions, labor and raw material costs, local, state, regional, and federal regulatory drivers, and site-specific considerations. Recently, capital costs have trended upward after a downward trend in the mid-late 1990s. These fluctuations have in large part, been driven by labor and material costs, the global nature of technology markets, and regulatory changes within the electric power sector [Sharp, 2007; Cichanowicz, 2007].

3.4.2 Dry Processes

Conventional dry processes include spray dryers (SDs) or “dry scrubbers” and Dry Sorbent Injection (DSI) technologies, and are shown in *Figure 3-2* and *Figure 3-3*, respectively. The technologies are referred to as “dry” because the SO_2 sorbent, while it may be injected as a slurry or a dry powder, is finally dried and collected in a conventional particulate control device, a fabric filter, or an ESP.

SD refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber vessel. DSI technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the “reactor,” and several configurations are possible based on the temperature window desired. This can occur at the furnace (1800-2200ºF), economizer (800-900ºF), or in a low-temperature duct (250-300ºF). In addition,

another common feature of dry scrubbing systems is the need for the particulate control equipment downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (although, depending on the application, ESPs may be used) that are not only efficient collectors of fine particulates, but can also provide some additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the bags. Dry processes are more compatible with low- to medium-sulfur coals because of the need to limit solid concentrations in the slurry below a threshold for adequate atomization and the need to limit the amount of solids collected in an existing particulate control device. This requirement precludes higher sulfur fuel applications where the required amount of reagent would be above that threshold. Therefore, high-sulfur applications are more typically associated with wet FGDs.

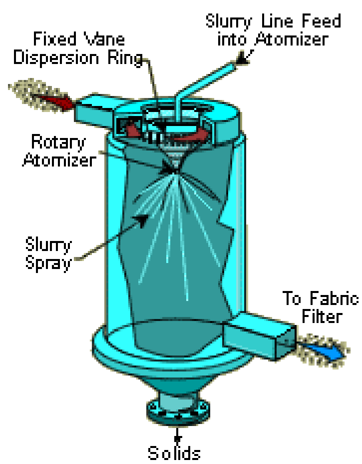

Figure 3-2. Schematic of a spray dryer [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

It is relevant to note that DSI technology did not gain any meaningful market penetration as part of the EGU compliance options to meet the requirements of the 1990 CAAA (Title IV) "acid rain" legislation for reducing emissions of SO_2. The large number of wet FGD installations in response to the Clean Air Act of 1970, and creation of "emission allowances," combined with the trend to switch fuels (mostly to low-sulfur Powder River Basin or PRB coal) in response to the 1990 CAAA, help explain this situation. However, more recently, interest in DSI technology applications for ICI boilers has been renewed and companies are "revamping" the knowledge base for DSI.

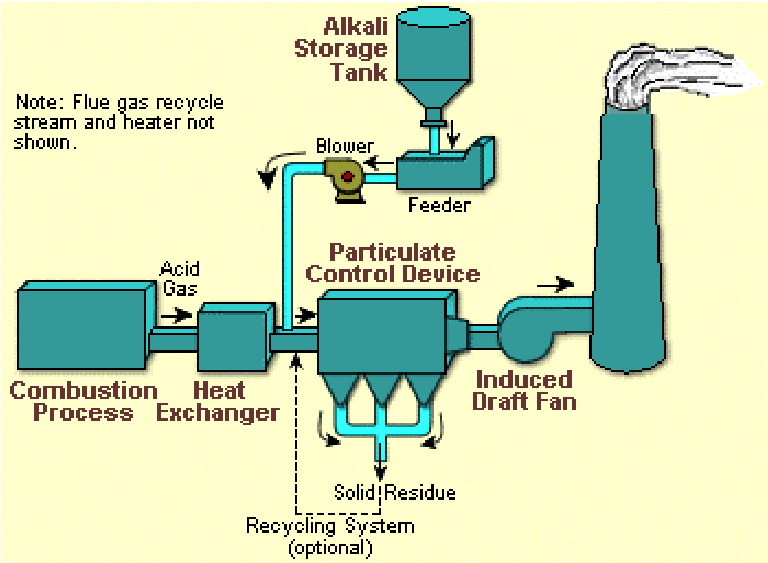

Figure 3-3. Dry Sorbent Injection (DSI) system diagram
[http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector. Companies such as O'Brien and Gere [Day, 2006; Day, 2007] and Siemens Environmental [Siemens, 2007] are marketing and deploying duct injection systems, and Nalco Mobotec [Haddad *et al.*, 2003] offers furnace sorbent injection (FSI) systems for ICI boilers. O'Brien and Gere, for example, have conducted over 5,000 hours of demonstrations at 15 different boilers since January 2005 to evaluate the viability, performance, and economics of DSI [Day, 2007]. These processes require relatively little new equipment and are thus suitable candidates for ICI boiler retrofit applications, where site constraints (e.g., space) are often critical.

Two examples of DSI systems are Furnace Sorbent Injection (FSI) in which hydrated lime is injected into the upper furnace of the boiler, and Lime Slurry Duct injection (LSDI) where atomized lime slurry is sprayed into the gas stream in the duct. FSI systems were first demonstrated in the 1980s on EGU boilers and are currently operating at ICI boilers [Dickerman, 2006].

FSI systems are capable of removing between 20 to 60 percent of the SO_2 and have shown removal percentages of as high as 90 to 99 percent for HCl and SO_3 [Haddad *et al.*, 2003]. The FSI systems also offer a low capital cost option and the attractiveness of quick cost recovery for ICI boiler sector [Dickerman, 2006].

The LSDI utilizes an atomized spray of lime slurry. The particles are subsequently captured in the downstream particulate collector. Sorbent particle size distribution is important for maximizing SO_2 capture while minimizing operational problems such as duct fallout and deposition.

LSDI systems have been utilized to mitigate plume generation from cement plants, and are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent [Dickerman, 2006].

In either case, both dry sorbent injection technologies offer an economical method for reducing emissions of SO_2. *Table 3-1* compares the FSI and LSDI systems for a 100 MW boiler, burning coal with one percent sulfur.

Table 3-1. Comparison of price for FSI and LSDI systems for a 100 MW coal-fired boiler [Dickerman, 2006]

Parameter	***FSI (Hydrated Lime)***	***LSDI***
SO_2 Removal	35%	50%
Reagent Cost ($\$10^3$/yr)	$1,400	$370
Parasitic Power ($\$10^3$/yr)	$182	$182
Disposal Cost ($\$10^3$/yr)	$168	$93
Subtotal ($\$10^3$/yr)	$1,750	$645
Capital Cost ($/kW)	$1,000,000 (10 $/kW)	$2,500,000 (25 $/kW)
Annual Capital Charge ($\$10^3$/yr)	$100	$250
Total Operating Cost ($\$10^3$/yr)	$1,850	$895
$/ton SO_2 Removed	$1,070	$311

Trona (sodium sesquicarbonate) is another reagent that has shown potential to reduce SO_2 emissions. A typical flow diagram is shown in *Figure 3-4* for injection of trona into a duct.

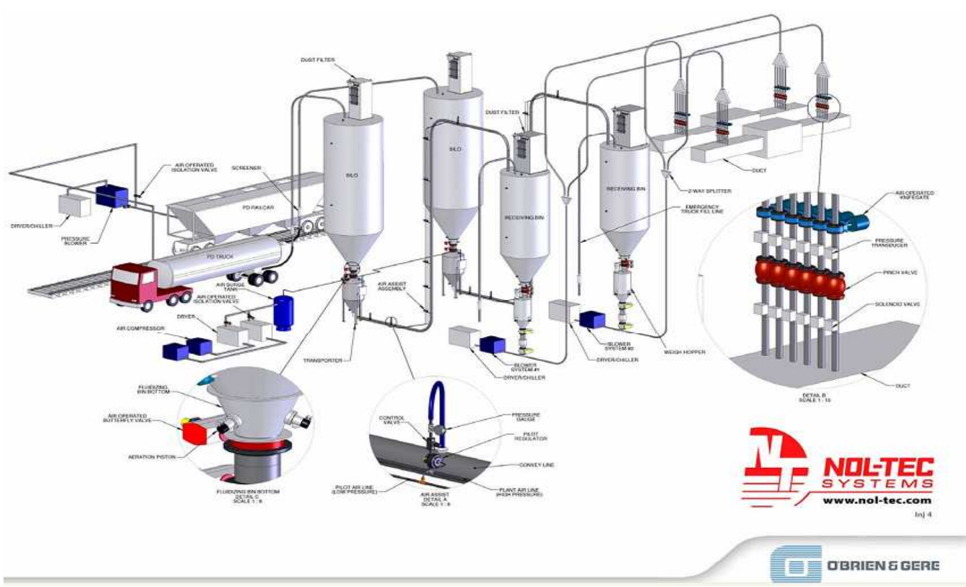

Figure 3-4. Flow diagram for trona DSI system [Day, 2006]

Trona's higher reactivity compared to lime helps it to offset the reaction stoichiometry advantage of lime. More importantly, due to the ability of trona to capture SO_2 when injected at higher temperatures [Cremer *et al.*, 2008], it is potentially applicable to many ICI boilers where flue gas temperatures may be higher that the desired ~300°F required for lime. *Figure 3-5* gives

some test data showing percent SO_2 reduction, [Day, 2006], averaged over several applications for units with ESPs.

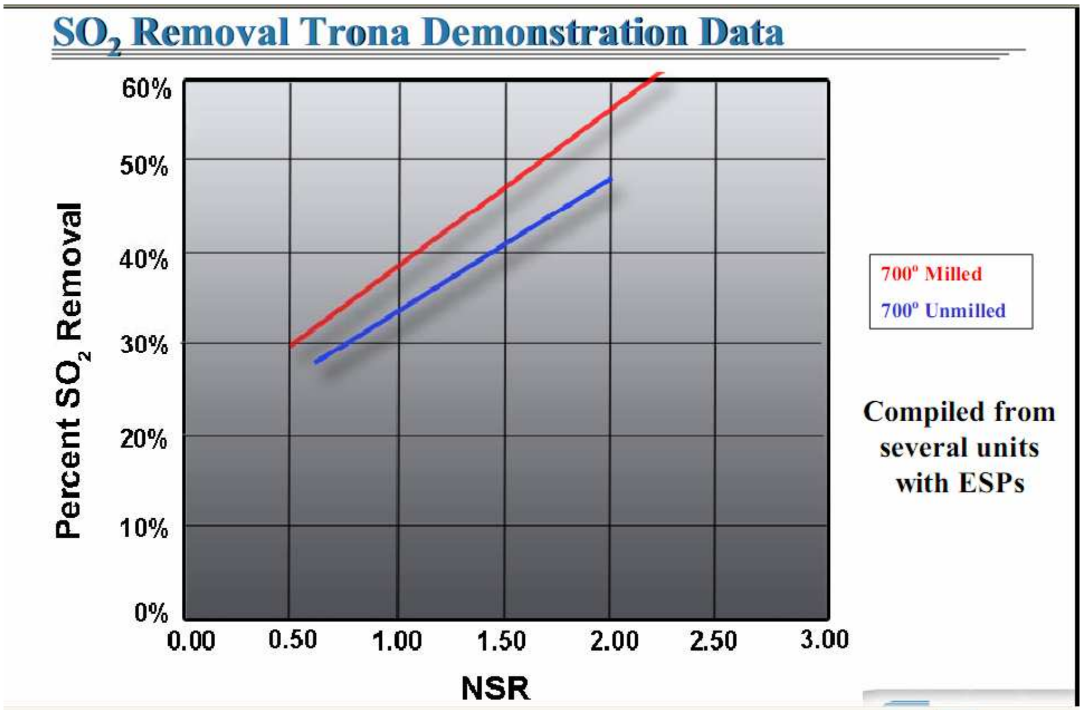

Figure 3-5. SO_2 removal test data [Day, 2007]

Figure 3-5 presents results for SO_2 reduction as a function of normalized stoichiometric ratio (NSR), which is the ratio of the reagent (trona in this case) to SO_2 in the flue gas. The two lines depict SO_2 reduction potential for two different sizes of trona at the same flue gas temperature of 700°F. Larger particles (unmilled) result in lower SO_2 reductions, as expected, relative to the milled condition (smaller particle size).

3.4.3 Other SO_2 Scrubbing Technologies

A number of other scrubber technologies have been developed for control of SO_2, but have not to date received significant market share. Among them are sodium- and ammonia-based wet scrubbing technologies. Some of these technologies, like the activated coke process [Dene, 2008], are regenerable (meaning the reagent can be regenerated and used repeatedly) and may produce useful byproducts, such as sulfuric acid, elemental sulfur, and ammonium sulfate. *Table 3-2* and *Table 3-3* present a comparison of the key performance characteristics and attributes for several alternative scrubbing technologies compared with conventional wet and dry scrubbers [Bozzuto, 2007].

Table 3-2. Comparison of alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Features	• High Efficiency • Low cost reagent • Byproduct flexibility	• Low investment cost • Dry byproduct • Small footprint • No liquid waste	• High value byproduct • Economics improved at high sulfur levels • Low operating cost	• Low investment cost • Operational simplicity
Pros	• Small flue gas flow • Operational simplicity required • Acute capital cost • Short evaluation period	• Low/medium sulfur fuel • Smaller flue gas flow • Short evaluation period	• High sulfur fuel • Larger flue gas flow • Gypsum market •Medium cost evaluation period	• High sulfur fuel • Larger flue gas flow • Fertilizer market
Cons	• Effluent discharge issue	• Limited landfill area • High lime/limestone cost ratio	• Acute capital cost sensitivity • Ultra-low PM emission requirements	• Acute capital cost sensitivity
Reagent	Limestone	Lime	Ammonia	Caustic, soda ash
Byproduct	Marketable gypsum or landfill	Landfill	Fertilizer	Sodium sulfate
SO_2 inlet	High	Low/medium	High	High
Removal Efficiency	>98%	90 – 95%	>98%	>98%

Table 3-3. Cost estimates for alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Capital Cost ($/acfm)	25 – 45	15- 25	35 – 60	10 – 20
Power Consumption (kW/acfm)	3-6	2	3-6	2-3
Reagent Cost ($/ton SO_2 removed.)	$15 – 25/ton	$60 – 75/ton	$80 – 105/ton	$100-130/ton
Byproduct Cost ($/ton SO_2 removed.)	$12 – 20/ton – disposal ($15/ton) – sale	$12 – 20/ton	$150 – 250/ton	??

3.5 Use of Fuel Oils with Lower Sulfur Content

Distillate fuel (No. 2 oil) is used in combustion systems in which an atomizer sprays droplets of oil into a combustion chamber and the droplets burn in suspension. Residual fuel oil (No. 6 oil) is also atomized and burned in ICI boilers. No. 6 oil is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of No. 6 oil in industrial combustion systems. A wide range of sulfur contents are available, from less than 0.3 wt% to greater than 3 wt%.

For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2. There is also an additional and important benefit of reduced emissions of $PM_{2.5}$. There are generally costs associated with switching to lower-sulfur fuels, which will undoubtedly vary from region to region.

Table 3-4 shows an example of the stocks of the fuel oils available on the East Coast and in the U.S. in 2006, taken from the Energy Information Administration (EIA) Petroleum Supply Annual [US EIA, 2006]. Substantial stocks of low-sulfur No. 6 fuel oil (less than 0.3 percent sulfur) and of ultra-low-sulfur No. 2 fuel oil (less than 0.0015 percent sulfur) were available both in the U.S. and on the East Coast.

Table 3-4. Distillate and residual oil stocks in 2006 (x1000 barrels) [US EIA, 2006]

	East Coast		**U. S. Total**	
Distillate Fuel Oil	**4,174**		**31,318**	
0.0015% sulfur and under	1,856	(44%)	16,531	(53%)
Greater than 0.0015% to 0.05% sulfur	560	(13%)	6,223	(20%)
Greater than 0.05% sulfur	1,758	(42%)	8,564	(27%)
Residual Fuel Oil	**2,486**		**11,936**	
Less than 0.31% sulfur	869	(35%)	1,291	(11%)
0.31 to 1% sulfur	975	(39%)	2,544	(21%)
Greater than 1% sulfur	642	(26%)	8,101	(68%)

Figure 3-6 shows the prices for residual oil and distillate oil from 1983 through 2007. The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been narrowing in recent years. The price of distillate oil in recent years, however, has been at times twice as much as the price of residual oil. The EIA prices for residual oil do not include a breakdown for very low sulfur residual oil (less than 0.31 percent sulfur). However, the prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm S), low-sulfur (15-500 ppm S), and high-sulfur (>500 ppm S). These prices, shown in *Figure 3-7*, do not show much difference in price as a function of sulfur content of No. 2 oil.

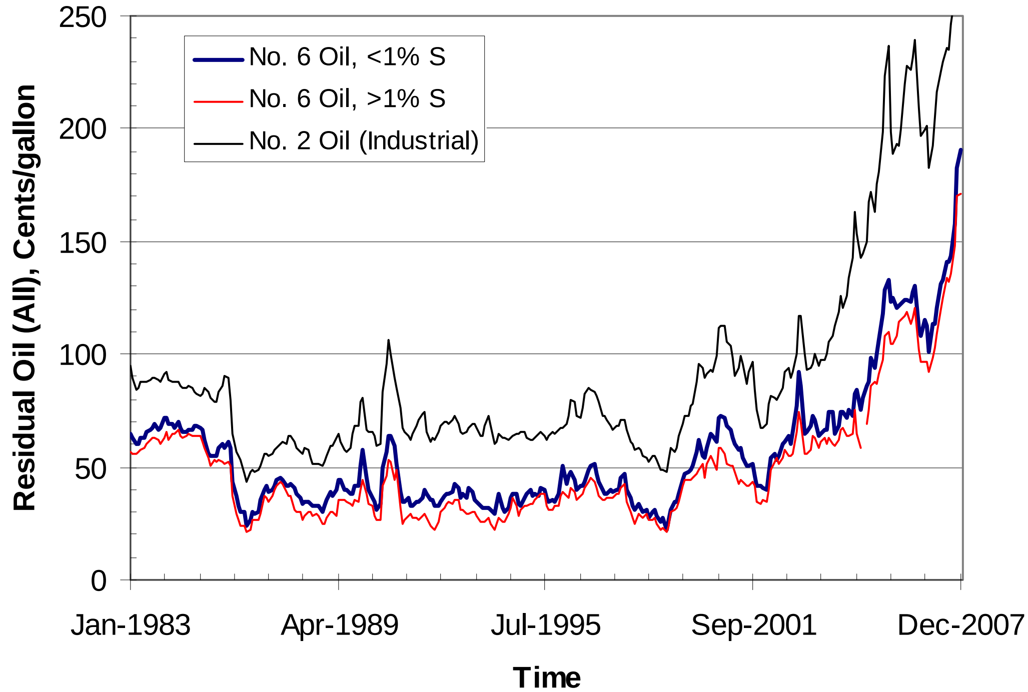

Figure 3-6. Industrial energy prices for No. 6 oil greater than 1 percent S, No. 6 oil less than 1 percent S, and No. 2 oil [Source: US EIA, 2008]

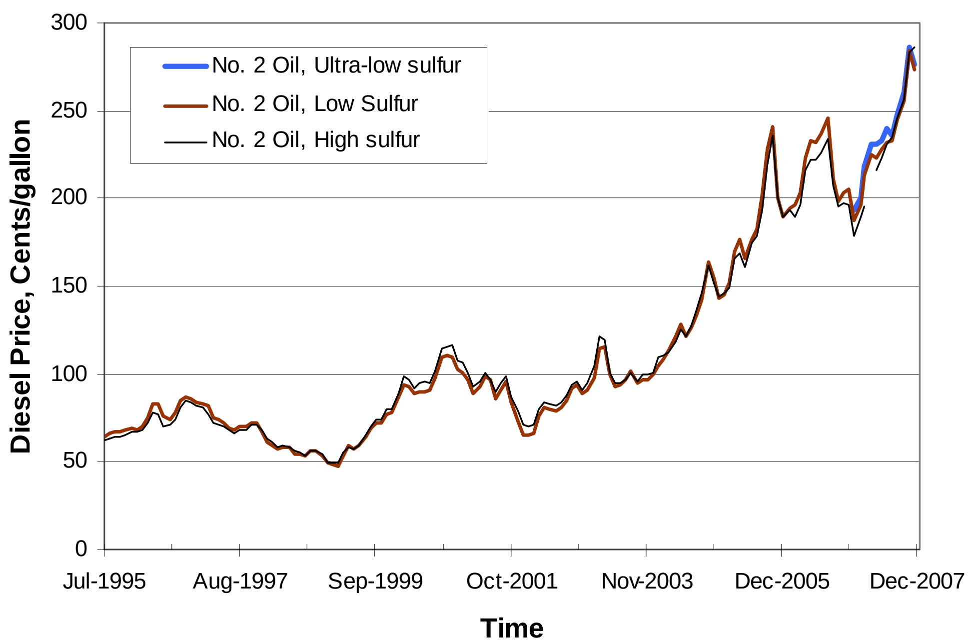

Figure 3-7. Industrial energy prices for No. 2 (distillate) oil [Source: US EIA, 2008]

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example, in which December 2007 fuel prices are used. If the high-sulfur residual oil is assumed to be 3 percent S, the low-sulfur residual oil is assumed to be 1 percent S, and the distillate oil is assumed to be 0.2 percent S, then the cost for fuel switching is shown in *Table 3-5*. These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in *Table 3-5* suggest that switching from a 3 percent sulfur residual fuel oil to a low-sulfur residual oil (1 percent S) would provide a cost-effective sulfur removal strategy at about $771 per ton of SO_2 removed. The cost of switching to distillate oil is estimated to be much higher than switching to low-sulfur residual oil, because the cost of distillate oil has been as much as twice that of residual oil in recent years. The cost effectiveness of a wet FGD for 90 to 99 percent SO_2 removal is in the range of $2,000 to $5,200/ton SO_2 (see Section 3.8). Thus, a switch to lower-sulfur fuel represents a cost-effective sulfur-compliance strategy for residual oil-fired boilers. The cost effectiveness (in dollars per ton of SO_2 removed) of switching from residual fuel oil to distillate fuel oil is not as attractive and is in the range of the cost effectiveness of installing a FGD or scrubber.

Table 3-5. Example of costs of switching to low-sulfur fuel oil [Fuel Prices from US EIA, 2008]

Fuel Switch	**SO_2 reduction**	**$/ton SO_2 removed (2007$)**
From 3% S to 1% Residual Oil*	66.7%	$771
From 3% S Residual to 0.2% Distillate**	93.6%	$5,335

*Assuming December 2007 prices for <1%S and >1%S residual oil
**Assuming December 2007 prices for >1%S and distillate oil

3.6 Applicability of SO_2 Control Technologies to ICI Boilers

The technologies described above are commercially available and are used extensively throughout the electric utility industry for coal-firing applications. The EGUs have deployed SO_2 controls (mostly wet and dry scrubbers) since the 1970s. ICI boilers firing coal are good candidates for the application of SO_2 control technologies. At least one oil-fired installation of a wet FGD has been noted in the literature [Caine and Shah, 2008]. Economics, however, will dictate preferred options on a case-by-case basis. It is likely that the higher capital-cost intensive technologies (e.g., wet and dry scrubbers) will be most attractive to larger ICI boilers, whereas the injection technologies (such as DSI) would likely be favored at smaller ICI boilers. The annualized cost of a wet FGD scrubber using wet sodium or alkaline waste can be lower relative to lime and limestone FGD, especially if low-cost waste disposal is available and the amount of SO_2 to be removed is small [Emmel, 2006]. This would suggest that smaller ICI boilers may not be good candidates for high capital-cost FGD systems. However, they should be good candidates for application of lower capital cost technologies such as DSI.

In terms of applicability, it is also important to recognize the impact of sulfur content of coal. Dry scrubbing has been typically restricted to low and medium sulfur coals (less than 2 wt% S) due to economic and technical considerations, including constraints associated with sorbent slurry concentration and adequate atomization performance. Lastly, while theoretically feasible, fluidized bed combustion (FBC) boilers are low emitters of SO_2 due to their inherent combustion process (bed temperature and composition), and are not likely candidates for SO_2 scrubber systems.

3.7 Efficiency Impacts

From the brief descriptions above, it should be clear that the common thread among the major SO_2 control technologies involves the reaction of SO_2 in the flue gas with a sorbent or reagent. The chemical reaction occurs either in a dedicated vessel (scrubber), or in the existing flue gas duct system. The major components affecting energy consumption for these systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. As expected, the energy penalties associated with a highly efficient (99 percent SO_2 reduction) wet scrubber are higher than for a less energy-intensive technology such as DSI.

The power consumption of SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. In other words, SO_2 control performance is related to reagent utilization, commonly referred to as liquid-to-gas (L/G) ratio for wet systems and normalized stoichiometric ratio or reagent (Ca or Na) to-sulfur ratio for dry technologies. This can be explained based on the fact that for a given SO_2 reduction level, lower quantities of reagent not only translate to lower reagent costs, but also to lower energy costs.

Table 3-6 summarizes performance and energy efficiency impacts for the three general SO_2 technologies discussed. It is important to note the values shown in the table, specifically in the "Energy Impact" column, represent nominal ranges based on generic combustion calculations and parasitic energy consumption for each technology. They are not site- or fuel-specific calculations, which are generally dependent on many variables, such as fuel composition, combustion and steam efficiencies, and operating conditions (e.g., excess air). However, these values represent broad, industry-wide averages for impacts of SO_2 control technologies on efficiency.

Table 3-6. Summary of energy impacts for SO_2 control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)
WFGD	Larger coal units, high sulfur coals, excluding FBC	90 - 95+	4 – 8+
Dry Scrubbers (SDs)	Larger units w/ low/medium sulfur coals, excluding FBC	70 – 90+	2 - 4
Duct Injection	Larger units w/ low/medium sulfur coals (FBC applications possible for additional "SO_2 trim")	30 – 60+	1 - 2

3.8 SO_2 Control Costs

Table 3-7 summarizes published SO_2 control costs for ICI boilers, as reported in the literature [Khan, 2003; US EPA, 2003; Whiteman, 2003; MACTEC, 2005]. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars/ton of SO_2 removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs, and reagents or consumables can make up a large portion of some of the operating costs. Costs of reagents and fuels (e.g., limestone, trona) change with time, but not always at the general rate of inflation. Thus, cost effectiveness values (or operating costs) from years before 2005 are not shown in the table. *Table 3-7* summarizes the published SO_2 control costs for a number of SO_2 control technologies.

A range of capital costs has been reported for sorbent injection technologies. *Figure 3-8* shows costs for dry duct injection (e.g., trona injection), wet duct injection (e.g., LSDI), and furnace sorbent injection (FSI). There was a large range of capital costs reported for dry sorbent injection. Wet sorbent injection (e.g., injection of hydrated lime slurry) was reported to have a significantly lower capital cost than dry sorbent injection. FSI capital costs were between dry and wet duct injection. The cost effectiveness (cost in dollars per ton of SO_2 removed) depends on the specific sorbent used and the stoichiometric ratio of sorbent to SO_2.

Table 3-7. SO_2 control costs applied to ICI boilers

Technology	SO_2 Reductio n Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
In-Duct Dry Sorbent Inj.	40%	High-S Coal	100	$34,228	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	250	$24,028	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	1000	$15,954	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	100	$22,953	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	250	$16,565	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	1000	$11,031	1999		1
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	100	$17,327	2003		3
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	250	$12,624	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	100	$8,663	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	250	$4,703	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	1000	$4,641	2003		3
Furnace Sorbent Inj.	70%	Coal	100	$26,609	2003		3
Furnace Sorbent Inj.	70%	Coal	250	$14,851	2003		3
Furnace Sorbent Inj.	70%	Coal	1000	$7,054	2003		3
Spray Dryer	90%	Coal	100	$69,744	1999		1
Spray Dryer	90%	Coal	250	$46,209	1999		1
Spray Dryer	90%	Coal	1000	$25,861	1999		1
Spray Dryer	90%	Coal	250	$13,300-188,820	2005	$1,712-3,578	4
Spray Dryer	95%	Coal	250	$13,300-188,820	2005	$1,622-3,390	4
Spray Dryer	90%	Oil	250	$13,300-188,820	2005	$1,944-5,219	4
Spray Dryer	95%	Oil	250	$13,300-188,820	2005	$1,841-4,945	4

Table 3-7 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet FGD	90%	High-S Coal	100	$81,939	1999		1
Wet FGD	90%	High-S Coal	250	$62,318	1999		1
Wet FGD	90%	High-S Coal	1000	$41,216	1999		1
Wet FGD	90%	Low-S Coal	100	$76,018	1999		1
Wet FGD	90%	Low-S Coal	250	$57,759	1999		1
Wet FGD	90%	Low-S Coal	1000	$38,122	1999		1
Wet FGD	90%	Coal	250	$11,507-172,672	2005	$2,089-3,822	4
Wet FGD	99%	Coal	250	$11,507-172,672	2005	$1,881-3,440	4
Wet FGD	90%	Oil	100	$69,848	1999		1
Wet FGD	90%	Oil	250	$53,066	1999		1
Wet FGD	90%	Oil	1000	$35,019	1999		1
Wet FGD	90%	Oil	250	$11,507-172,672	2005	$2,173-5,215	4
Wet FGD	99%	Oil	250	$11,507-172,672	2005	$1,956-4,694	4

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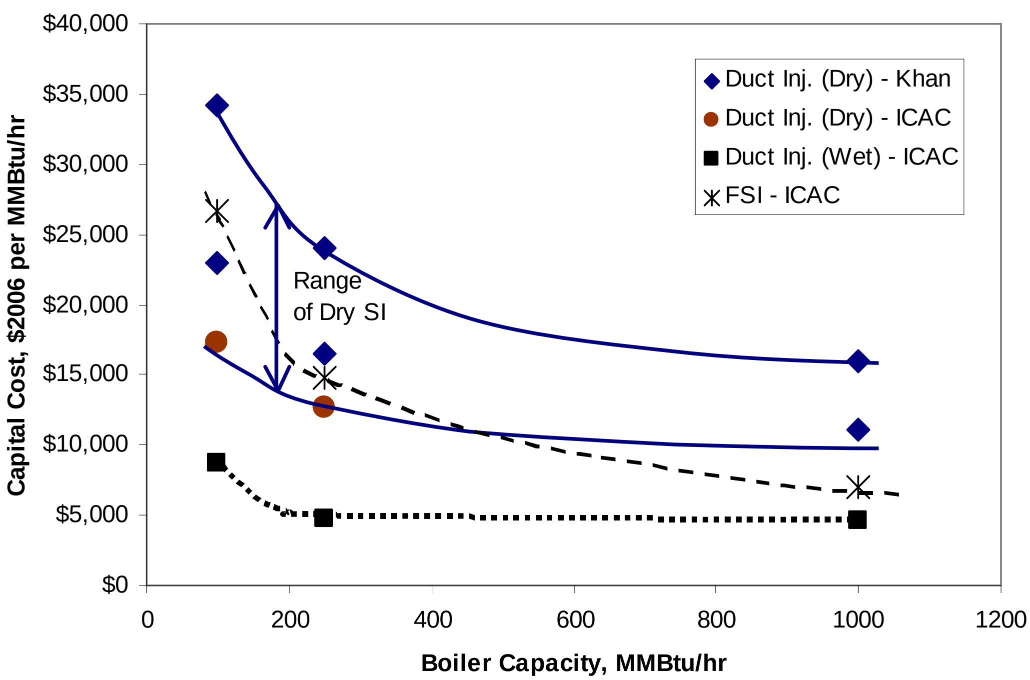

Figure 3-8. Capital cost for SO_2 control for dry sorbent injection applied to ICI boilers as a function of boiler capacity

Spray dryer (SD) technology has been widely applied to coal-fired EGUs. Estimates in the literature for SD technology for ICI boilers give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005]. *Figure 3-9* summarizes these capital costs for ICI boilers. Note that the MACTEC estimates at 250 MMBtu/hr boiler size assumed high and low equipment cost, but a detailed cost breakdown was not given.

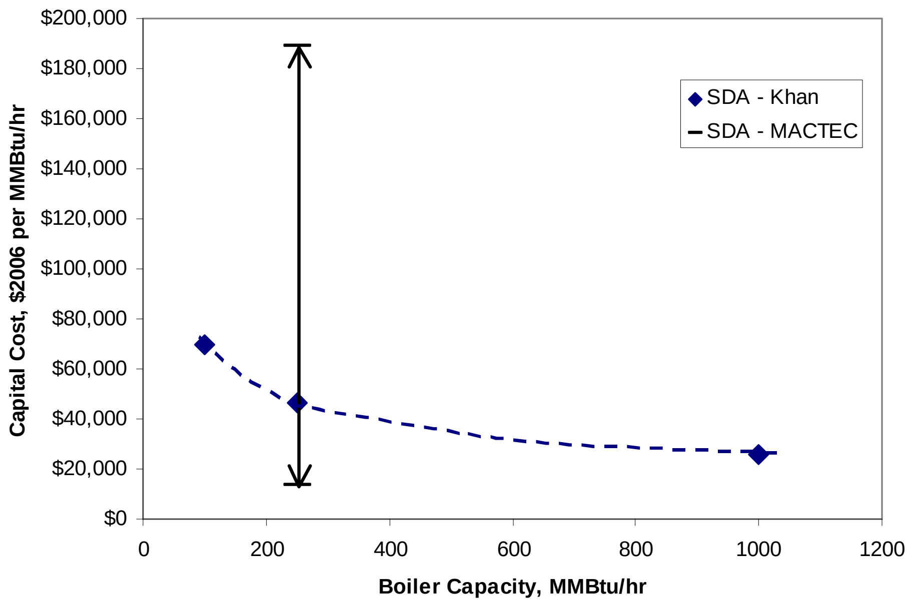

Figure 3-9. Capital cost for SO_2 control for Spray Dryer Absorber applied to ICI boilers as a function of boiler capacity

Wet FGD technology has been widely applied to coal-fired EGU boilers but rarely to ICI boilers, although at least one oil-fired installation has been noted in the literature [Caine and Shah, 2008]. The relationship between FGD capital cost and boiler capacity is shown in *Figure 3-10*. Estimates in the literature give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005], although these estimates are not always based on actual field installation data because installations of wet FGD technology on ICI boilers are few at present.

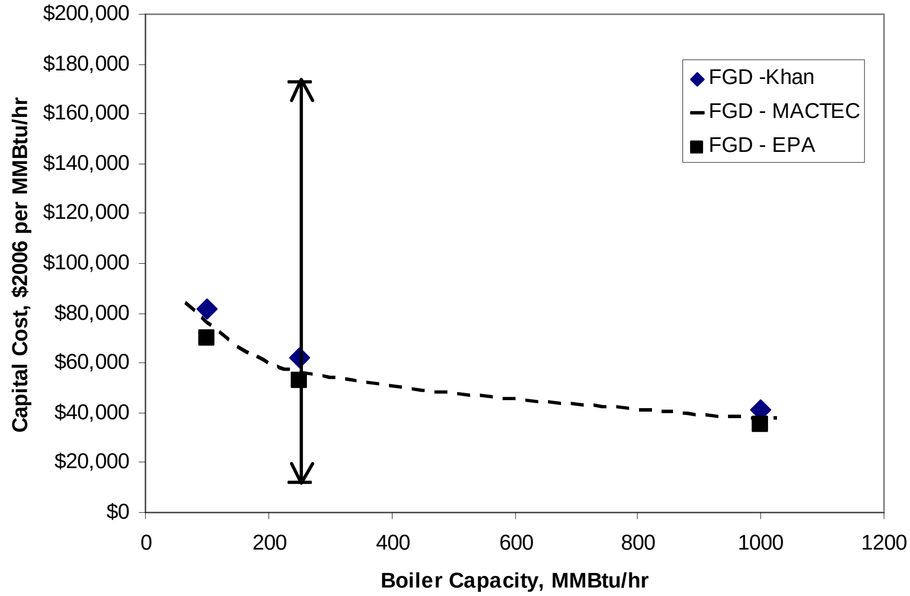

Figure 3-10. Capital cost for SO_2 control for wet FGD applied to ICI boilers as a function of boiler capacity

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4 PM CONTROL TECHNOLOGIES

4.1 PM Formation in Combustion Systems

PM emissions from combustion processes include primary and secondary emissions. Primary emissions consist mostly of fly ash. Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter (PM_{10} and $PM_{2.5}$). Fly ash refers to the mineral matter of the fuel, which typically includes some level of unburned carbon. ICI boilers burn a variety of fuels that contain ash and, as such, have PM emissions. Therefore, ICI boilers are candidates for PM controls.

Coal and oil contain non-combustible ash material. Other liquid or solid fuels (e.g., petroleum coke, wood) also contain ash. The quantity of ash in the flue gas depends on many factors, such as fuel properties, boiler design, and operating conditions. In dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash, and the remaining ash is collected as bottom ash. However, in wet-bottom, pulverized-coal-fired boilers, about 50 percent of the total ash exits the boiler as fly ash. In cyclone boilers (common in the EGU sector but not in the ICI population), most of the ash is retained as liquid slag, and the fly ash is only about 20 percent of the total ash. Fluidized-bed combustors (FBC) emit high levels of fly ash because the coal is fired in suspension and the ash is present in dry form. Stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers because combustion takes place in a relatively quiescent fuel bed.

In addition to the nitrates and sulfates mentioned as secondary PM, NOx control technologies that inject ammonia or amine-based reagents (SNCR and SCR) yield a certain amount of ammonia "slip," which can also form fine particulate (ammonium sulfate) as the flue gas temperatures decrease towards the stack.

This section presents a brief description of the major primary PM technologies.

4.2 PM Control Technologies

PM control technologies have been commercially available and widely used in ICI and EGU boilers for many years. *Table 4-1* summarizes the main types of commercially available technologies.

Table 4-1. Available PM control options for ICI boilers

Technology	Description	Applicability	Performance
Fabric filters (Baghouse)	"Baghouses" made of close-knit fabrics remove particulates through filtration.	Primarily used in coal/wood fired industrial/utility boilers. Not used with oil boilers due to clogging.	>99% total and $PM_{2.5}$ removal
ESPs (Dry/Wet)	Charged particles attracted to oppositely charged plates. Collection method either wet/dry.	Widely used in coal applications. Suitable for oil, pet coke and waste solid fuels. Wet ESPs suitable for saturated flue gas.	Effectiveness depends on resistivity of particulates. Low sulfur can reduce performance of dry ESP. >99% reduction of total PM (dry/wet) and sulfuric acid mist and $PM_{2.5}$ (wet)
Venturi Scrubbers	Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste.	High pressure required for significant removal. Applicable to a wide range of fuels.	50% removal for fine particulates, 99% removal for large (>5 micron) particulates
Cyclones	Cyclones use aerodynamic forces to separate particles from the gas stream.	Widely applicable to all fuels.	70%-90% total PM potential

4.3 Description of Control Technologies

4.3.1 Fabric Filters

Fabric filters (also called baghouses) are essentially giant vacuum cleaners and very effective devices for collecting dry PM from flue gas. They are used in ICI and EGU applications, although less widely than ESPs. Separation occurs when the ash-laden flue gas passes through a porous layer of filter material. As the individual particles accumulate on the surface of the filter, they gradually form a layer of ash known as the "dust cake." Once formed, the dust cake provides most of the filtration. However, they are not particularly well suited for wet gas applications due to the negative impact of wet gas on the bag filters. *Figure 4-1* shows a photograph of the internal components of a fabric filter compartment with several individual bags and mounting mechanisms.

Figure 4-1. Photograph of fabric filter compartment with filter bags [Source: www.hamon-researchcottrell.com]

As shown in *Figure 4-1*, multiple bags are assembled in compartments to provide a large surface area for filtration. The large surface area is required to maintain acceptable pressure loss across the fabric. Groups of bags are placed in compartments, which can be isolated from one another to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse.

Baghouse size is typically defined in terms of “air-to-cloth” ratio, expressed in the units of velocity in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The size of the baghouse depends on the particulate loading and characteristics, and the cleaning method used.

The type of bag cleaning method employed characterizes baghouses. Cleaning intensity and frequency are important because the dust cake provides a significant fraction of the fine particulate removal capability of a fabric. Hence, too frequent or too intense a cleaning method may lower the removal efficiency. Conversely, if removal of this dust cake happens infrequently or inefficiently, the pressure drop will increase to unacceptable levels. The major cleaning methods are as follows.

- Reverse-air baghouse – In this case, the flue gas flows upward through the vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken off-line, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers.
- Pulse-jet baghouse – In this case, the dust is collected on the outside of the bags, which are mounted on cages to keep them from collapsing. Dust is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, allowing it to be done on-line. Because pulse-jet cleaning is more intensive than in reverse-air baghouses, the bags in a pulse-jet baghouse remain relatively clean, resulting in the ability to use a higher air-to-cloth ratio or a smaller baghouse compared to the reverse-air type.

Additionally, fabric filters can also be used in applications where fly-ash resistivity makes it difficult for collection with ESPs. Further, baghouses are capable of 99.9 percent removal efficiencies, as well as being able to remove the smaller size PM fraction ($PM_{2.5}$) more efficiently.

4.3.2 Electrostatic Precipitators

ESP's operate on the principle of electrophoresis by imparting a charge to the particulates and collecting them on opposed charged surfaces. Dry vs. wet ESPs refer to whether the gas is water-cooled and saturated prior to entering the charged collection area or is dry. *Figure 4-2* and *Figure 4-3* show schematic views of dry and wet ESPs, respectively. Older ESPs are often of the wire-pipe design, in which the collecting surface consists of one or more tubes (operated wet or dry). The wire-plate design is the other commonly used ESP design, as illustrated in the schematic in *Figure 4-2*.

In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 µm on a mass basis with wet ESPs being capable of such reductions well into the sub-micron level (0.01 µm) [Altman, 2001].

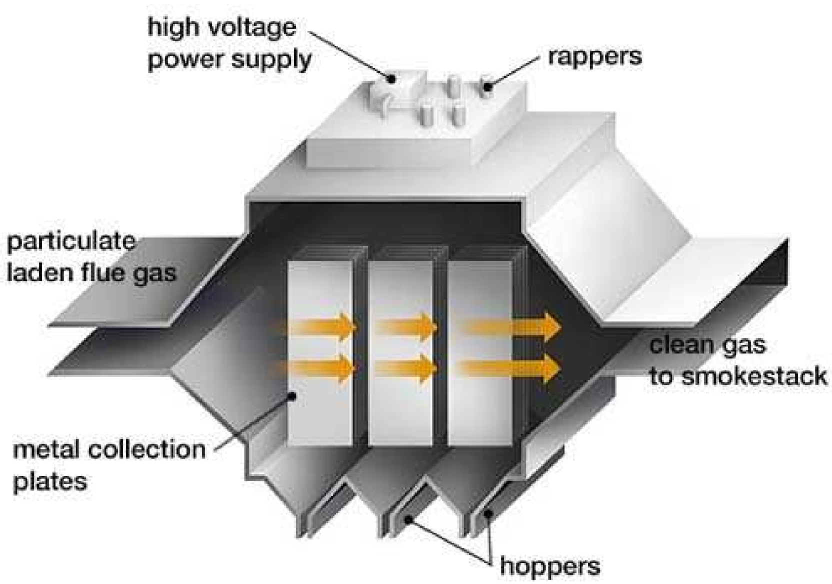

Figure 4-2. Side view of dry ESP schematic diagram [Source: Powerspan]

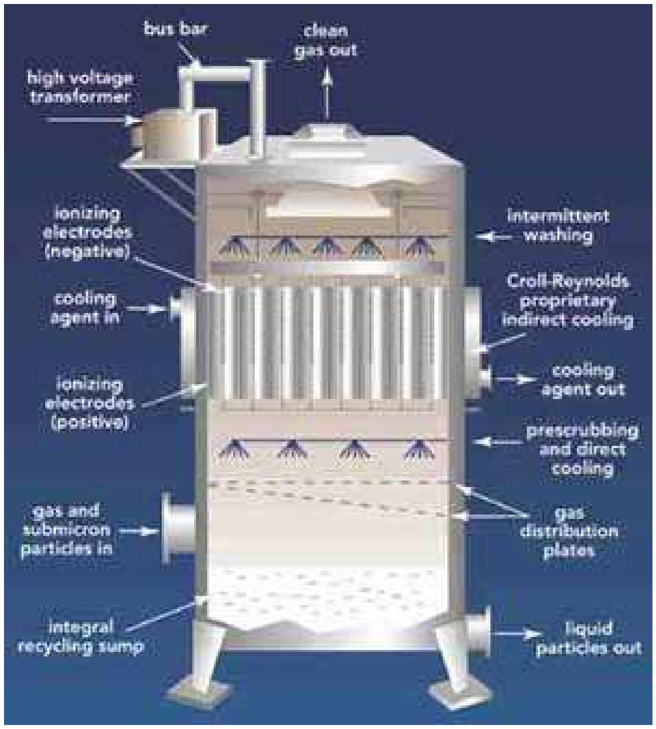

Figure 4-3. Wet ESP [Croll Reynolds]

Compared to fabric filters, ESPs affect the flue gas flow minimally, resulting in much lower pressure drops then an equivalent baghouse (typically less than two inches H_2O vs. greater than six inches H_2O for the fabric filter).

An electric field between high-voltage discharge electrodes and grounded collecting electrodes produces a corona discharge from the discharge electrodes, which ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The negatively charged particles are attracted to the collecting electrodes. To remove the collected fly ash, the collecting electrodes are rapped mechanically, causing the fly ash to fall into hoppers for removal.

A balance generally needs to be struck between higher voltages for higher particulate removal efficiency and excessive sparking which will have the opposite effect. Larger ESPs are sectionalized (see *Figure 4-2*) such that higher voltages can be used in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages are then used in the last, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. This has the added advantage that particles re-entrained in the flue gas stream by rapping (striking the electrode to dislodge the dust) may be collected in the downstream sections of the ESP.

Precipitator size is a major variable affecting overall performance or collection efficiency. Size determines residence time (the time a particle spends in the precipitator). Precipitator size also is typically defined in terms of the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher SCA leads to higher removal efficiencies. Collection areas can range from as low as 200 to as high as 800 ft^2/1000

acfm. In order to achieve collection efficiencies of 99.5 percent, SCA of 350-400 ft^2/1000 acfm is typically used. The overall (mass) collection efficiencies of ESPs can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies can achieve high efficiencies across a range of particle sizes so that good control of PM_{10} and $PM_{2.5}$ is possible with well designed and operated electrostatic precipitators.

Unlike dry ESPs, which use rapping to remove particulates from the collecting electrodes, wet ESPs use a water spray to remove the particulates. By continually wetting the collection surface, the collecting walls never build up a layer of particulate matter. This means that there is little or no deterioration of the electrical field due to resistivity, and power levels within a wet ESP can therefore be higher than in a dry ESP. The ability to inject greater electrical power within the wet ESP and elimination of secondary re-entrainment are the main reasons a wet ESP can collect sub-micron particulate more efficiently.

Overall, ESPs have historically been the collection device of choice for many applications in the ICI boiler and EGU boiler sectors. High removal efficiencies are possible and the units are rugged and relatively insensitive to operating upsets. Wet ESPs offer performance characteristics for capturing $PM_{2.5}$ similar to fabric filters and are well suited for applications such as oil firing, for which fabric filters are less attractive, because the sticky ash particles produced from oil combustion can blind the bags.

4.3.3 Venturi Scrubbers

Venturi scrubbers for PM control operate on the principle of rapid mixing and impingement of PM with liquid droplets and subsequent removal with the liquid waste. For particulate controls, the venturi scrubber is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressure drops are required. High-energy scrubbers operate at pressure losses of 50 to 70 inches of water. Higher pressure drop translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis. However, venturi scrubbers are seldom used as the primary PM collection device because of excessive pressure drop and associated energy penalties. *Figure 4-4* depicts a venturi scrubber.

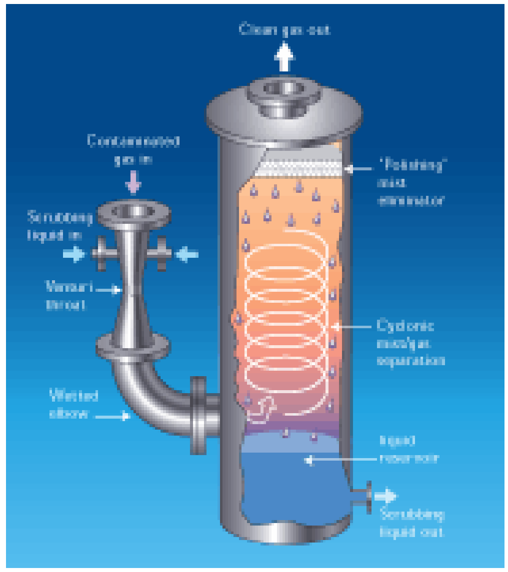

Figure 4-4. Venturi scrubber [Croll Reynolds]

4.3.4 Cyclones

Cyclones are devices that separate particulates from the gas stream through inertial forces. As ash-laden gas enters the cyclone near the top, a high-velocity vortex is created inside the device. Heavy particles move outward due to centrifugal force and begin accumulating on the wall of the cyclone. Gravity continuously forces these particles to move downward where they collect in the lower, hopper region of the cyclone. The collected particles eventually discharge through an opening in the bottom of the hopper into a system that transports the particles to a storage area. Smaller and lighter particles that remain suspended in the flue gas move toward the center of the vortex before being discharged through the clean-gas outlet located near the top of the cyclone (see *Figure 4-5*).

Cyclones are comparatively simple devices in design and construction, with no moving parts. Cyclones can operate over a wide range of temperatures, which makes them attractive for smaller ICI boilers that do not have economizers and/or air preheaters (and thus higher stack temperatures than in EGU boilers). Pressure drops across cyclones are typically in the range of 2 to 8 inches of water for a single cyclone. Cyclones can be arranged in arrays (multi-cyclones) and have overall mass removal efficiencies of 70 to 90 percent with the corresponding increase in pressure drop. However, cyclone collection efficiencies are very sensitive to particle size, and control efficiency for fine particulate ($PM_{2.5}$) is poor [Licht, 1988].

Cyclones are most effective at high boiler loads, where flue gas flow rates are highest. From an operational perspective, cyclones have no moving parts, are not sensitive to fuel quality or gas temperature, and require only regular cleaning to avoid plugging. These characteristics have made them good options in the past, particularly in the absence of regulatory $PM_{2.5}$ requirements.

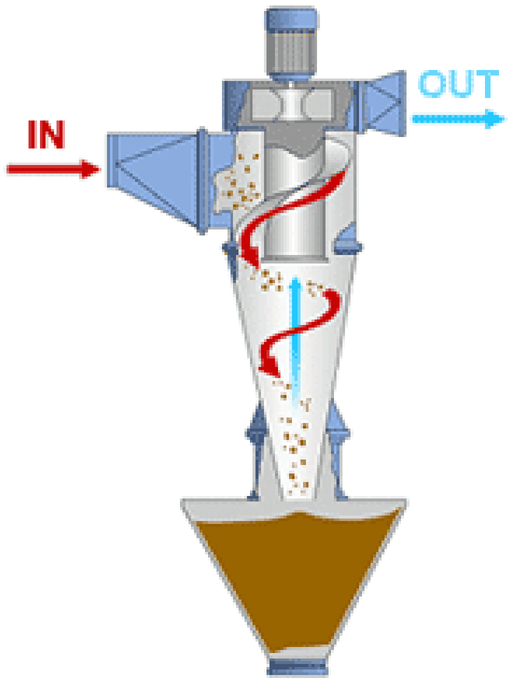

Figure 4-5. Schematic of a cyclone collector [www.dustcollectorexperts.com/cyclone]

Due to the limited potential for $PM_{2.5}$ capture, use of cyclones in new combustion applications is primarily limited to fluidized-bed boilers where they are used to re-circulate the bed material – and not as primary PM control devices.

4.3.5 Core Separator

The core separator is a mechanical device that operates based on aerodynamic separation (like cyclones), but also utilizes a "core separator." The separator portion of the device consists of multiple cylindrical tubes with one inlet and two outlets. One outlet allows for a clean gas stream to exit, while the other outlet is used for recirculating the concentrated stream. This recirculation stream then passes through the cyclone unit (see *Figure 4-6* [Resource Systems Group, 2001]), where it is further cleaned and returned to the separator. This sequential process enhances its overall control efficiency as compared to single or multiple cyclones.

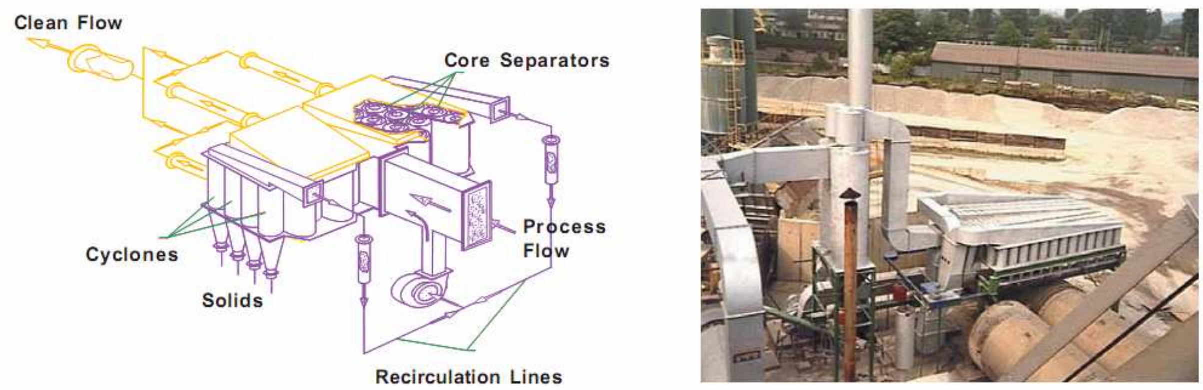

Figure 4-6. Schematic (left) and actual (right) core separator system [EPA, 2003]

The core separator capability for PM removal falls between that of an ESP and a cyclone. Several systems are currently installed on coal- and wood-fired boilers. The core separator unit is capable of overall PM reductions of up to the 90 percent range. Its collection efficiency, however, diminishes to about 50 percent for $PM_{2.5}$. *Table 4-2* displays inlet and outlet PM concentrations and removal efficiency of a core separator at two different plants. *Table 4-3* presents estimated costs for the core separator for two different sizes and gas flow conditions.

Table 4-2. Core separator collection efficiency [USEPA, 2008; Resource Systems Group, 2001]

Core Separator Inlet Loading (lb/million Btu)	Core Separator Outlet Loading (lb/million Btu)	Removal Efficiency	Boiler Type
0.17	0.07	59%	Wood Fired
0.846	0.214	75%	Stoker – Coal

Table 4-3. Core separator cost analysis [B. H. Eason to P. Amar, 2008]

Boiler Size	MMBtu/hr	8	10
	Estimated gas temperature (°F)	500	500
	Estimated gas flow rate (acfm)	4979	5996
Core Separator Size and Estimated Price (uninstalled)	Gas Flow per 12” module	660	660
	Number of 12” Modules	7	9
	Estimated price	$110,000	$130,000
	Gas Flow per 24” Module	2640	2640
	Number of 24” Modules	1	2
	Estimated Price	$55,000	$83,000

4.4 Applicability of PM Control Technologies to ICI Boilers

The PM control technologies described in this section are widely available and are used in both ICI and EGU applications. Because all these PM controls are based on the collection of particulates from the flue gas, they are applicable to a variety of boiler types and ash-containing

fuels, including coal, oil, wood, petroleum coke, and other waste fuels. Determining the most attractive option for individual applications is a case-by-case decision that needs to account for technical, economic, and regulatory considerations. One exception, as mentioned, is that fabric filters are not suitable for fuel oil applications due to the “stickiness” and composition of the ash.

4.5 Efficiency Impacts

PM control technologies do result in some parasitic energy loss as can be deduced from the brief descriptions of technologies above (see *Table 4-1*). The inherent energy losses associated with each technology are given below and summarized in *Table 4-4*.

- For Fabric Filters
  - compressor (bag cleaning)
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For ESPs
  - transformer-rectifier (TR) power
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For Venturi Scrubber and Cyclone
  - flue gas pressure loss

Table 4-4. Summary of energy impacts for control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)	Comments
Fabric Filter	Coal, Wood	99+	1 – 2	Pressure loss / compressor / ash handling
Dry ESP	Coal, Oil, Wood	99	0.5 – 1.5	Pressure loss / TR power / ash handling
Wet ESP	Coal, Oil, Wood	99+	3 - 6	Pressure loss / TR power / ash handling
Venturi Scrubber	Coal, Oil, Wood	70-90 (Not efficient for $PM_{2.5}$)	5 - 11	Pressure loss
Cyclone	Coal, Wood	70-90 (Not efficient for $PM_{2.5}$)	0.5 – 1.5	Pressure loss

4.6 PM Control Costs

The following tables summarize published PM control costs for ICI boilers reported in the literature [US EPA, 2003a; US EPA, 2003b; US EPA, 2003c; US EPA, 2003d; US EPA, 2003e; US EPA, 2003f; MACTEC, 2005]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness

in dollars per ton of PM removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some of the operating costs, but these items do not always increase with the rate of inflation for chemical plant equipment. Thus, cost effectiveness values (or operating costs) from years before 2005 have not been reported.

Table 4-5 summarizes the published PM control costs for several different PM control technologies. In the EPA references, the capital costs were given in terms of dollars/scfm (2002 dollars). These costs were converted to dollars per MMBtu/hr using the flow rates given in Chapter Five and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values.

The MACTEC capital costs [MACTEC, 2005] span a large range, because high and low estimates for capital equipment were used in the calculation. The EPA capital costs are much higher for the wire-pipe ESP (also known as a tubular ESP) than the wire-plate ESP. Note that a size was not given in the EPA cost estimate, so a range is shown. The capital cost comparison is similar for wet ESPs although the capital costs themselves (in dollars/MMBtu/hr) are higher for wet ESPs as compared to dry ESPs.

For fabric filters, pulse-jet and reverse-air fabric filters were considered. These types of equipment have similar collection efficiencies, but the capital costs and effectiveness of pulse-jet fabric filters are lower than that of reverse-air fabric filters.

Table 4-5. PM control costs applied to ICI boilers

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu /hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Dry ESP	90%	Coal	250	$12,365-$160,754	2005	$171-$1,300	7
Dry ESP	99%	Coal	250	$12,365-$160,754	2005	$156-$1,172	7
Dry ESP	90%	Oil	250	$6,713-$87,275	2005	$2,584-$21,009	7
Dry ESP	99%	Oil	250	$6,713-$87,275	2005	$2,328-$18,912	7
Dry ESP (Wire-Pipe)		Coal	--	$6,571-$41,070	2002		1
Dry ESP (Wire-Plate)	90%-99%	Coal	--	$3,286-$10,843	2002		2
Dry ESP (Wire-Pipe)		Resid.Oil	--	$5,198-$32,486	2002		1
Dry ESP (Wire-Plate)	90%-99%	Resid.Oil	--	$2,599-$8,576	2002		2
Dry ESP (Wire-Pipe)		Dist.Oil	--	$5,117-$31,983	2002		1
Dry ESP (Wire-Plate)	90%-99%	Dist.Oil	--	$2,559-$8,443	2002		2
Dry ESP (Wire-Pipe)		Wood	--	$7,560-$47,249	2002		1
Dry ESP (Wire-Plate)	90%-99%	Wood	--	$3,780-$12,474	2002		2
ESP	99.50%	Wood	Small	--	2005	$594	8
ESP	99.50%	Wood	Medium	--	2005	$203-$292	8
ESP	99.50%	Wood	Large	--	2005	$114-130	8
Fabric Filter	90%	Coal	250	$7,453-$93,158	2005	$444-$1,006	7
Fabric Filter	99%	Coal	250	$7,453-$93,158	2005	$423-$957	7
Pulse-Jet Fabric Filter	95%-99.9%	Coal	--	$1,971-$8,543	2002		5
Reverse-Air FF	95%-99.9%	Coal	--	$3,286-$28,585	2002		6
Fabric Filter	90%	Oil	250	$4,046-$50,577	2005	$7,277-$16,464	7
Fabric Filter	99%	Oil	250	$4,046-$50,577	2005	$6,915-$15,643	7
Pulse-Jet Fabric Filter	95%-99.9%	Resid.Oil	--	$1,559-$6,757	2002		5
Reverse-Air FF	95%-99.9%	Resid.Oil	--	$2,559-$22,260	2002		6
Pulse-Jet Fabric Filter	95%-99.9%	Dist.Oil	--	$1,535-$6,652	2002		5
Reverse-Air FF	95%-99.9%	Dist.Oil	--	$2,599-$22,610	2002		6
Fabric Filter	99.50%	Wood	Small	--	2005	$958	8
Fabric Filter	99.50%	Wood	Medium	--	2005	$147-249	8
Fabric Filter	99.50%	Wood	Large	--	2005	$91-$107	8
Pulse-Jet Fabric Filter	95%-99.9%	Wood	--	$2,268-$9,829	2002		5
Reverse-Air FF	95%-99.9%	Wood	--	$3,780-$32,886	2002		6

Table 4-5 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet ESP	90%	Coal	250	$25,968-$252,260	2005	$906-$2,627	7
Wet ESP	99.9%	Coal	250	$25,968-$252,260	2005	$815-2,365	7
Wet ESP (Wire-Pipe)	90%-99.9%	Coal	--	$13,142-$65,712	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Coal	--	$6,571-$13,142	2002		4
Wet ESP	90%	Oil	250	$14,098-$136,955	2005	$14,938-$43,036	7
Wet ESP	99.9%	Oil	250	$14,098-$136,955	2005	$13,446-$38,736	7
Wet ESP (Wire-Pipe)	90%-99.9%	Resid.Oil	--	$10,395-$51,977	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Resid.Oil	--	$5,198-$10,395	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Dist.Oil	--	$10,235-$51,172	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Dist.Oil	--	$5,117-$10,234	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Wood	--	$15,120-$75,599	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Wood	--	$7,560-$15,120	2002		4

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5 APPLICATION OF A COST MODEL TO ICI BOILERS

When evaluating the applicability of pollution control equipment to a specific ICI boiler, cost and performance capability need to be considered. A number of cost estimation models have been created for estimation of capital and operating costs of retrofit technology for air pollutants. However, most of the cost models have been developed for and applied to EGUs burning coal. Much less work has been carried out on cost estimation models for ICI boilers. In this Chapter, a cost modeling approach currently used for estimating control costs for coal-burning EGUs is modified and then investigated for its applicability to ICI boilers burning coal as well as other fuels. The purpose of this Chapter is to present this modified cost model (CUECost-ICI) and resulting cost calculations. The strengths and weaknesses of this approach are also discussed. However, the purpose of this effort is not to carry out an exhaustive calculation of costs, but to generate a set of reasonable cost estimates for ICI boilers burning different fuels and compare them with published cost information.

5.1 Cost Model Inputs and Assumptions

The Coal Utility Environmental Cost (CUECost) model was developed by Raytheon Engineers for EPA; version 3, and is available on EPA's website at http://www.epa.gov/ttn/catc/products.html. The model calculates capital and operating costs for certain predefined air pollution control devices for control of NOx, SO_2, and PM as applied to coal-fired power plants. The CUECost model produces approximate cost estimates (±30 percent accuracy) of the installed capital and annualized operating costs. The CUECost model was originally designed for and is intended for use on coal-fired boilers greater in size than 100 MW (about 1,000 MMBtu/hr heat input).

Table 5-1 gives the general plant inputs that are needed to set up the model; more inputs are needed for specific air pollution control devices (see Appendix B).

Table 5-1. CUECost general plant inputs

Input Parameter	***Comment***
Location - State	
MW Equivalent of Flue Gas to Control System	*This was designed for EGUs, but can be scaled to generate the appropriate gas flow for ICIs*
Net Plant Heat Rate	*Function of the efficiency of the plant*
Plant Capacity Factor	*Use averages from EEA study, parametric variations*
Percent Excess Air in Boiler	*Assume 3% O_2 for NG and oil, 7% O_2 for coal, wood*
Air Heater In-leakage	*Determines the flow rate for downstream devices such as scrubbers and particulate control devices*
Air Heater Outlet Gas Temperature	
Inlet Air Temperature	
Ambient Absolute Pressure	
Pressure After Air Heater	
Moisture in Air	
Ash Split:	*Depends on firing system*
Fly Ash	
Bottom Ash	
Seismic Zone	
Retrofit Factor	*Moderate effect on total capital requirement (TCR)*
(1.0 = new, 1.3 = medium, 1.6 = difficult)	
Select Fuel	*User can define "coal" with respect to HHV, %S, %ash*

The EPA version of CUECost contains the following modules for specific air pollution control devices:

- Limestone forced-oxidation, wet FGD scrubber
- Lime spray dryer
- FF
- ESP
- SCR
- SNCR
- LNB
- Natural Gas Reburn

CUECost bases the costs of equipment and operation on the generating capacity (in MW of electricity generated) of a given boiler. Industrial boilers are usually rated by the heat input (in MMBtu/hr); the boiler heat rate is used to convert from heat input to the equivalent size in MW. In order to use CUECost in its present form for ICI boilers, an equivalent size in MW needs to be estimated, although this could be modified in a dedicated ICI boiler version of CUECost (which was not developed in this effort).

Industrial boilers are operated differently from utility boilers, and the inputs for CUECost-ICI must be adjusted accordingly, including:

- Heat rate
- Excess air level

- Flue gas temperatures
- Capacity factor

The default values in the current version of CUECost for EGUs generally do not describe ICI boilers well. Fuel compositions vary widely for ICI boilers, while the EGU version of CUECost includes coal as the only fuel option (with different compositions). However, the user can define other fuels, as described below.

An important factor in determining total installed capital cost is the choice of appropriate retrofit factor, which expresses the difficulty of installing a control technology in an existing plant. In CUECost a retrofit factor of 1.0 denotes a new plant (corresponding to the lowest capital cost), and retrofit factors of 1.3 and 1.6 denote medium and difficult retrofits, respectively. Emmel [2006] noted that this range of retrofit factors significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs less than 100 MW. Emmel also noted that on average a retrofit factor of 1.45 was more reasonable and that the factor should be even higher when CUECost is applied to ICI boilers.

The technology options in CUECost are also fixed, and the user cannot create a new technology option without supplying formulae for calculating the capital equipment cost. The technology options for SO_2 control in CUECost, in particular, have been noted to be more appropriate for larger utility boilers than for ICI boilers. Wet FGD and spray dryer technology – the SO_2 scrubbing options in CUECost – are based on lime or limestone reagents and have high capital and operating costs compared to alkaline scrubbers or duct injection. The latter scrubbing options might be more attractive for ICI boilers, but would have to be added to the current version of CUECost.

Finally, Emmel [2006] notes that most ICI boiler sites will have higher contingency, general facility, engineering, and maintenance costs (on a percentage of capital cost basis) than those identified for EGUs in CUECost in order to take into account necessary upgrades or demolition of existing facilities that are less likely to be needed at sites.

In this effort, the CUECost model was adapted for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. Capital and operating costs in the model were based on correlations derived from coal-fired power plant experience since no reliable field data were available for the ICI boilers. It is not clear how robust the correlations for capital equipment are for small (≤ 25 MW equivalent) boilers.

The CUECost model is based on the electrical generating capacity. A combustion calculation was used to relate heat input rate to equivalent MW for five different fuels.

Table 5-2 gives the properties of these fuels. Boiler efficiency was specified, and heat rate was calculated from boiler efficiency. The uncontrolled or baseline emissions were based on fuel composition (in the case of SO_2 and PM) or on industry operating experience (in the case of NOx).

Table 5-3 shows the results (in terms of calculated flue gas flow rates) of the combustion calculations for a fixed heat input rate of 250 MMBtu/hr or 100 MMBtu/hr. Flue gas flow rate is an important parameter or input to the cost model, because the size of capital equipment is often related to the flue gas flow rate.

Table 5-2. Fuel characteristics and assumptions for CUECost calculation of heat rate and flue gas flow rates

	Bituminous	**Wood**	**No.2 Oil**	**No.6 Oil**	**Gas**
C, wt%	76.2	27.6	86.4	85.8	75
S, wt%	2.5	0.04	0.6	2.5	0
H, wt%	4.6	3.3	12.7	10.6	25
Moisture, wt%	1.4	45	0.02	0.02	0
N, wt%	1.4	0.3	0.1	0.5	0
O, wt%	7	22.86	0.1	0.5	0
Ash, wt%	6.9	0.9	0.08	0.08	0
Fuel heating value, BTU/lb	13,630	4,633	19,563	18,273	20,800
Unburned carbon, wt% in ash	5	1	75	75	0
Boiler efficiency*	34%	30%	39%	39%	45%
Stack O_2, vol% dry	7%	7%	3%	3%	3%
Boiler heat rate, Btu/kWh	10,000	11,370	8,750	8,750	7,600
Uncontrolled or Baseline emissions NOx, lb NO_2/MMBtu	0.60	0.26	0.20	0.40	0.40
SO_2, lb/MMBtu	3.67	0.17	0.61	2.74	0.00
PM, lb/MMBtu	5.06	1.94	0.04	0.04	0.00

*Fuel to MW

Table 5-3. Equivalent heat input rate and flue gas flow rates for 250 and 100 MMBtu/hr heat input rates

	MW	MMBtu/hr	Flue gas, scfm
Bituminous coal (34% efficiency, 7% O_2)	25.0	250	65,305
Wood (30% efficiency, 7% O_2)	22.0	250	81,184
No.2 oil (39% efficiency, 3% O_2)	28.6	250	50,622
No.6 oil (39% efficiency, 3% O_2)	28.6	250	51,117
Natural gas (45% efficiency, 3% O_2)	32.9	250	59,336
Bituminous coal (34% efficiency, 7% O_2)	10.0	100	26,122
Wood (30% efficiency, 7% O_2)	8.8	100	32,474
No.2 oil (39% efficiency, 3% O_2)	11.4	100	20,178
No.6 oil (39% efficiency, 3% O_2)	11.4	100	20,375
Natural gas (45% efficiency, 3% O_2)	13.2	100	23,806

5.2 Comparison of the Cost Model Results with Literature

A comparison was made of the CUECost-ICI model with other published information for a selection of fuels and air pollution control devices applied to ICI boilers. Where possible, the inputs for the model were set to be the same as information cited in the literature.

Using the appropriate fuel composition and boiler heat rates, the modified ICI version of the original CUECost (CUECost-ICI) model was run for a number of ICI boiler cases. *Table 5-4*, *Table 5-5*, and *Table 5-6* show the installed capital costs, first-year annual operating costs, and cost per ton of pollutant removed for NOx, SO_2, and PM, respectively. Capital and operating costs were calculated on 2006 dollars basis in the CUECost-ICI model. A complete

list of inputs to CUECost-ICI is included in Appendix B. For the NOx and SO_2 control technologies, percentage reduction of the pollutant was used as an input, so that the CUECost-ICI results could be easily compared to published literature results. For PM controls, a specific emission limit (in lb/MMBtu) was used as an input and the percentage PM reduction was calculated from the fuel ash content.

Table 5-4. Capital and operating costs for NOx control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost/ton
250	80.0%	Coal	SCR	Ammonia	$4.394	$1.253	$4,763
100	80.0%	Coal	SCR	Ammonia	$2.585	$0.702	$6,668
250	80.0%	No.6 Oil	SCR	Ammonia	$2.923	$0.790	$3,972
100	80.0%	No.6 Oil	SCR	Ammonia	$1.760	$0.460	$5,805
250	80.0%	Nat.Gas	SCR	Ammonia	$3.005	$0.811	$4,673
100	80.0%	Nat.Gas	SCR	Ammonia	$1.805	$0.472	$6,777
250	50.0%	Coal	SNCR	Ammonia	$1.142	$0.398	$2,422
100	50.0%	Coal	SNCR	Ammonia	$0.969	$0.317	$4,817
250	50.0%	No.6 Oil	SNCR	Ammonia	$0.724	$0.338	$2,722
100	50.0%	No.6 Oil	SNCR	Ammonia	$0.407	$0.196	$3,961
250	50.0%	Nat.Gas	SNCR	Ammonia	$0.785	$0.362	$3,335
100	50.0%	Nat.Gas	SNCR	Ammonia	$0.443	$0.209	$4,798
250	40.0%	Coal	LNB	--	$1.227	$0.301	$2,290
100	40.0%	Coal	LNB	--	$0.677	$0.166	$3,155
250	40.0%	No.6 Oil	LNB	--	$1.339	$0.329	$3,305
100	40.0%	No.6 Oil	LNB	--	$0.737	$0.181	$4,559
250	40.0%	Nat.Gas	LNB	--	$1.467	$0.360	$4,151
100	40.0%	Nat.Gas	LNB	--	$0.810	$0.199	$5,715

Table 5-5. Capital and operating costs for SO_2 control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	95%	Coal	wFGD	Limestone	$38.096	$11.137	$4,427
100	95%	Coal	wFGD	Limestone	$33.680	$9.608	$9,547
250	95%	No.6 Oil	wFGD	Limestone	$36.642	$10.733	$5,713
100	95%	No.6 Oil	wFGD	Limestone	$32.805	$9.368	$12,510
250	90%	Coal	SD	Lime	$29.598	$8.806	$3,694
100	90%	Coal	SD	Lime	$26.263	$7.540	$7,909
250	90%	No.6 Oil	SD	Lime	$28.463	$8.371	$4,704
100	90%	No.6 Oil	SD	Lime	$25.723	$7.344	$10,352

Table 5-6. Capital and operating costs for PM control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	PM Emission, lb/MMBtu	Installed Capital Cost, $M	Capital cost, $/scfm	Capital cost, $/acfm	Annua l Cost, $M	Cost Effective ness (dollars per ton)
250	99.3%	Coal	ESP	0.03	$4.05	$62.00	$43.00	$1.11	$342
100	99.3%	Coal	ESP	0.03	$2.31	$88.50	$61.50	$0.63	$485
250	99.3%	Coal	FF	0.03	$4.77	$73.00	$50.70	$1.32	$406
100	99.3%	Coal	FF	0.03	$2.88	$110.20	$76.60	$0.78	$592
250	95.8%	No.6 Oil	ESP	0.01	$3.40	$66.60	$46.30	$0.93	$5,689
100	95.8%	No.6 Oil	ESP	0.01	$2.02	$99.00	$68.80	$0.55	$8,410
250	95.8%	No.6 Oil	FF	0.01	$4.09	$80.00	$55.60	$1.14	$6,940
100	95.8%	No.6 Oil	FF	0.01	$2.50	$122.80	$85.30	$0.68	$10,354

For comparison, the American Forest & Paper Association (AF&PA) calculated SNCR control costs in 2006 for wood-fired boilers ranging in size from 88 to 265 MMBtu/hr [Hunt, 2006]. *Table 5-7* below compares the AF&PA costs with the CUECost-ICI costs for wood-fired boilers. The installed capital cost values agree well between CUECost-ICI and the AF&PA estimates, although the CUECost-ICI values for cost effectiveness (dollars per ton of NOx removed) are 20 to 25 percent lower than the AF&PA estimates.

Table 5-7. Capital and operating costs for SNCR on wood-fired boilers, comparison of cost calculations from AF&PA and CUECost

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost, $/ton
AF&PA							
88.5	70.0%	Wood	SNCR	Urea	$0.924	$0.250	$11,283
176.9	70.0%	Wood	SNCR	Urea	$1.400	$0.384	$8,574
285.4	70.0%	Wood	SNCR	Urea	$1.786	$0.502	$7,480
CUECost							
88.5	70.0%	Wood	SNCR	Urea	$0.923	$0.289	$9,239
176.9	70.0%	Wood	SNCR	Urea	$1.025	$0.324	$5,174
285.4	70.0%	Wood	SNCR	Urea	$1.130	$0.361	$5,011

Finally, the CUECost-ICI model results for capital cost were compared with some of the values reported in the literature [US EPA, 1996; NESCAUM, 2000; US EPA, 2003a; US EPA, 2003b; Whiteman, 2006], where available. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using Chemical Engineering Plant Cost Index values.

The NOx capital costs computed with CUECost-ICI were largely consistent with the literature values. (Chapter Two contains a detailed discussion of the literature values for NOx control costs.)

Figure 5-1 compares capital costs for SCR for boilers burning coal, residual (No. 6) oil, and natural gas. The SCR costs appear to be consistent with the literature values. The literature value for SCR as reported by the Ozone Transport Assessment Group (OTAG) [US EPA, 1996] did not describe its basis in any detail, so it is difficult to determine if the OTAG cost estimates assumed a significantly different space velocity or different equipment than assumed in the CUECost-ICI model.

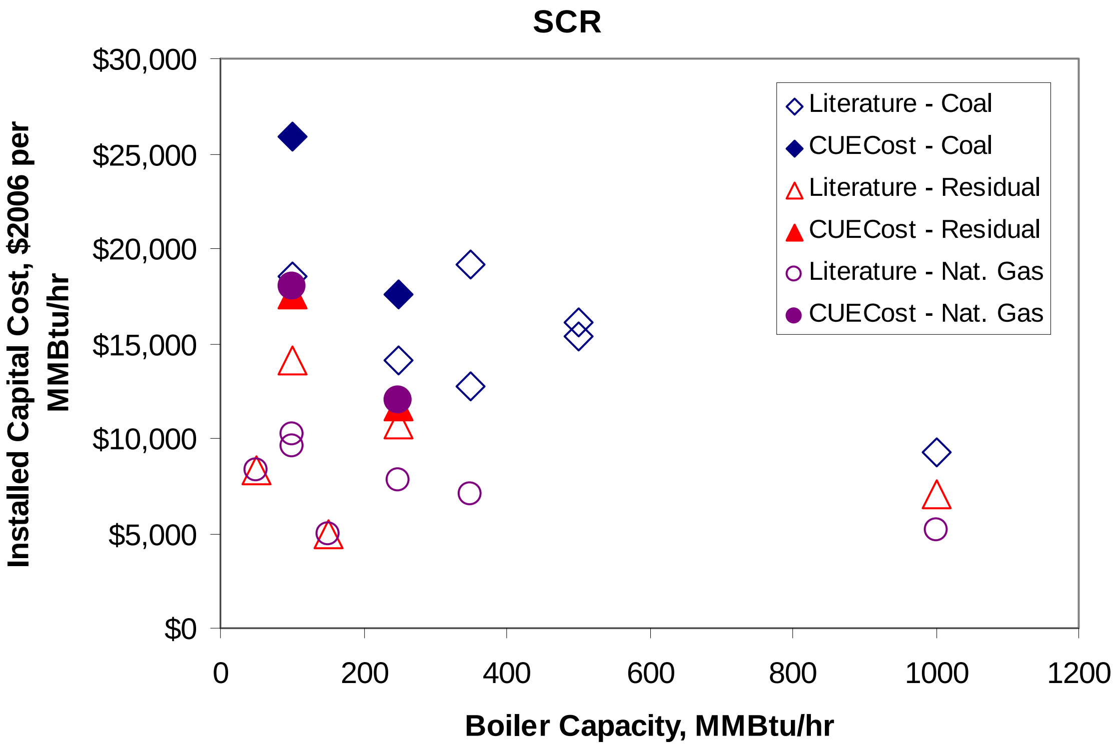

Figure 5-1. Comparison of CUECost-ICI model and reported literature values for capital cost of SCR for NOx control

The capital costs for SNCR (*Figure 5-2*) calculated from the CUECost-ICI model are in good agreement with literature values, particularly the sensitivity of capital cost to boiler capacity, which was also noted by ICAC [Whiteman, 2006].

The capital costs for LNB (*Figure 5-3*) calculated from the CUECost-ICI model for coal-fired boilers were consistent with the literature values, although the capital costs for residual oil-fired boilers were higher in the CUECost-ICI model than the literature values. Again, no details were provided in the literature references.

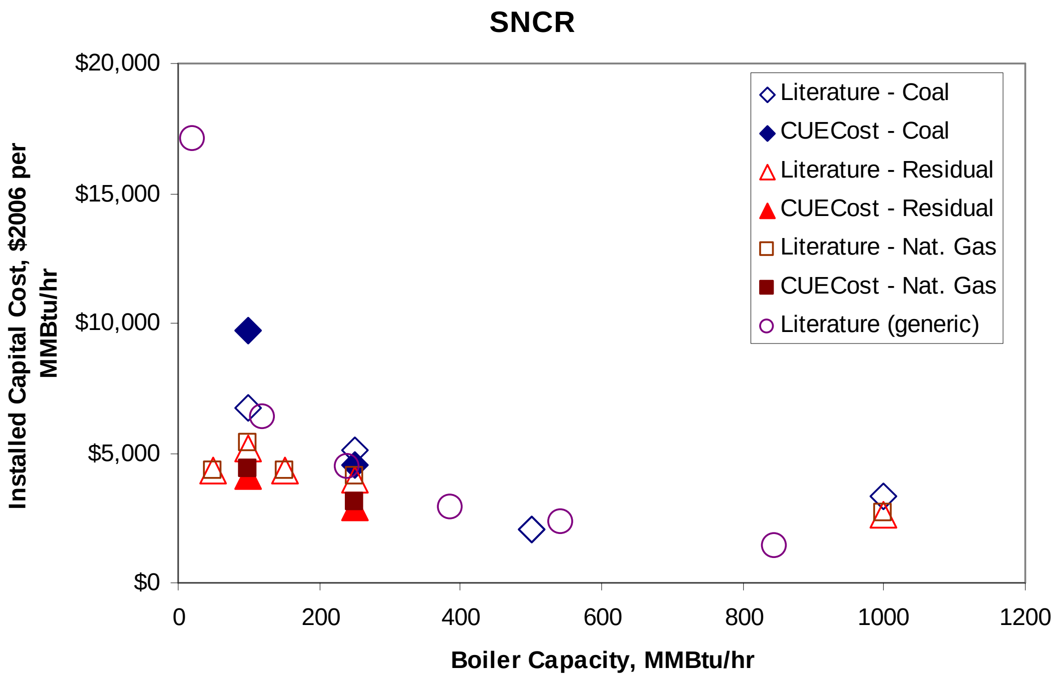

Figure 5-2. Comparison of CUECost-ICI model and reported literature values for capital cost of SNCR for NOx control

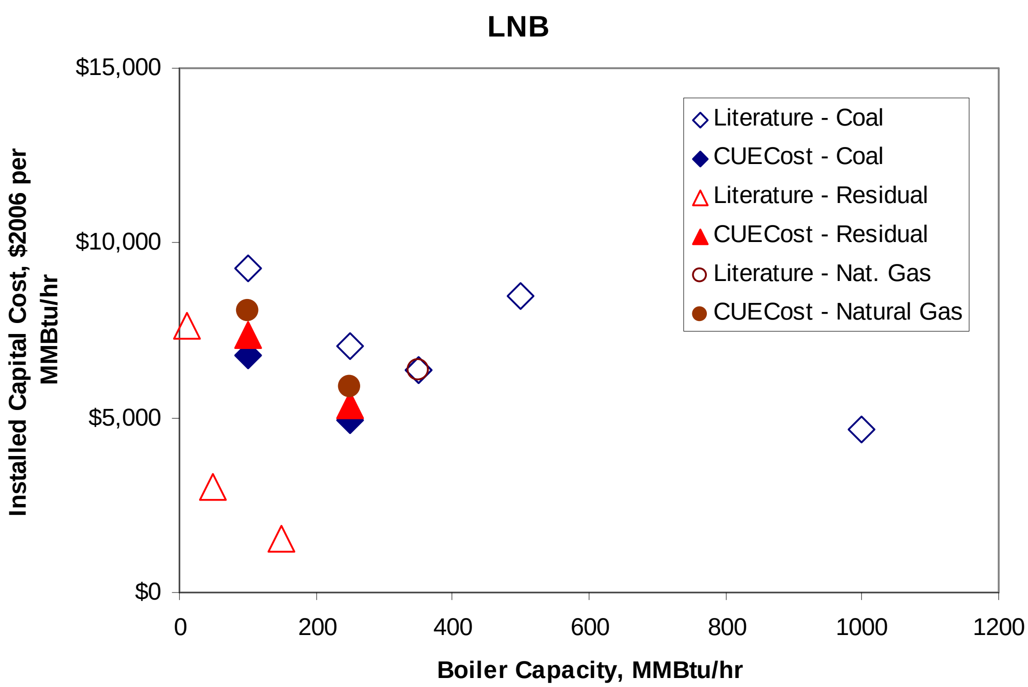

Figure 5-3. Comparison of CUECost-ICI model and reported literature values for capital cost of LNB for NOx control

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs. The SO_2 capital costs computed with CUECost-ICI for spray dryers (SDs) were in the range of the literature values at boiler size of 250 MMBtu/hr (*Figure 5-4*). No literature data were available for residual oil-fired boilers and spray dryers. However, the capital costs calculated by CUECost –ICI for wet FGDs (*Figure 5-5*) were high when compared to the literature values.

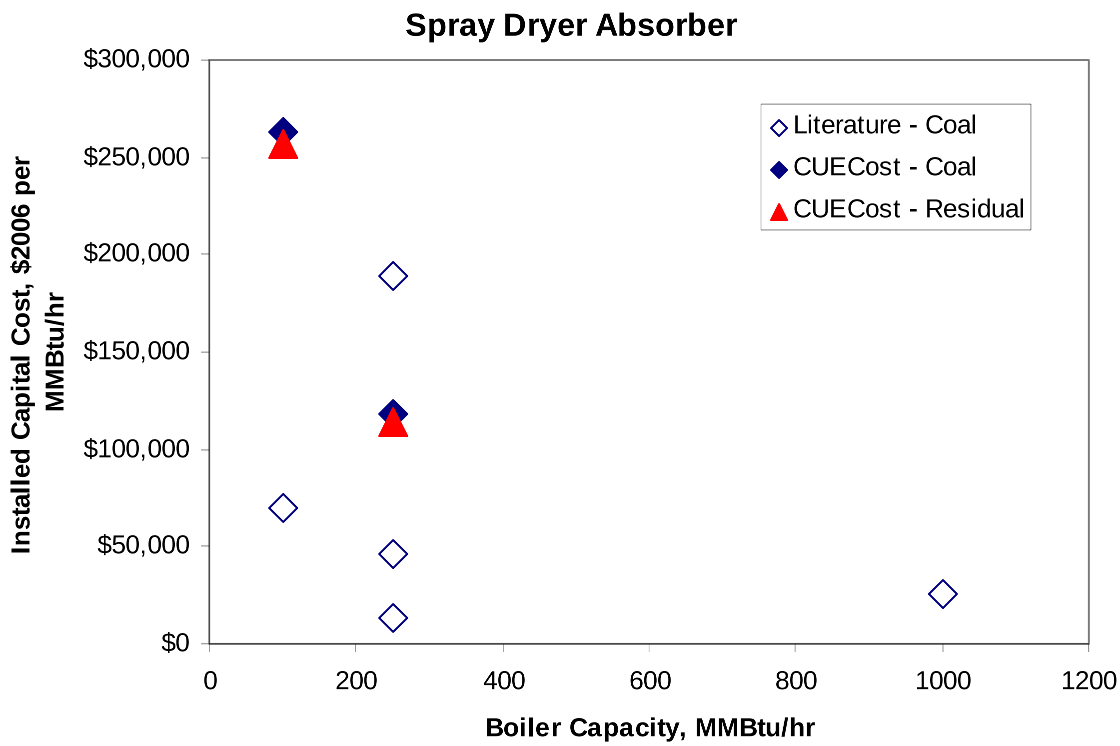

Figure 5-4. Comparison of CUECost-ICI model and reported literature values for capital cost of Spray Dryer for SO_2 control

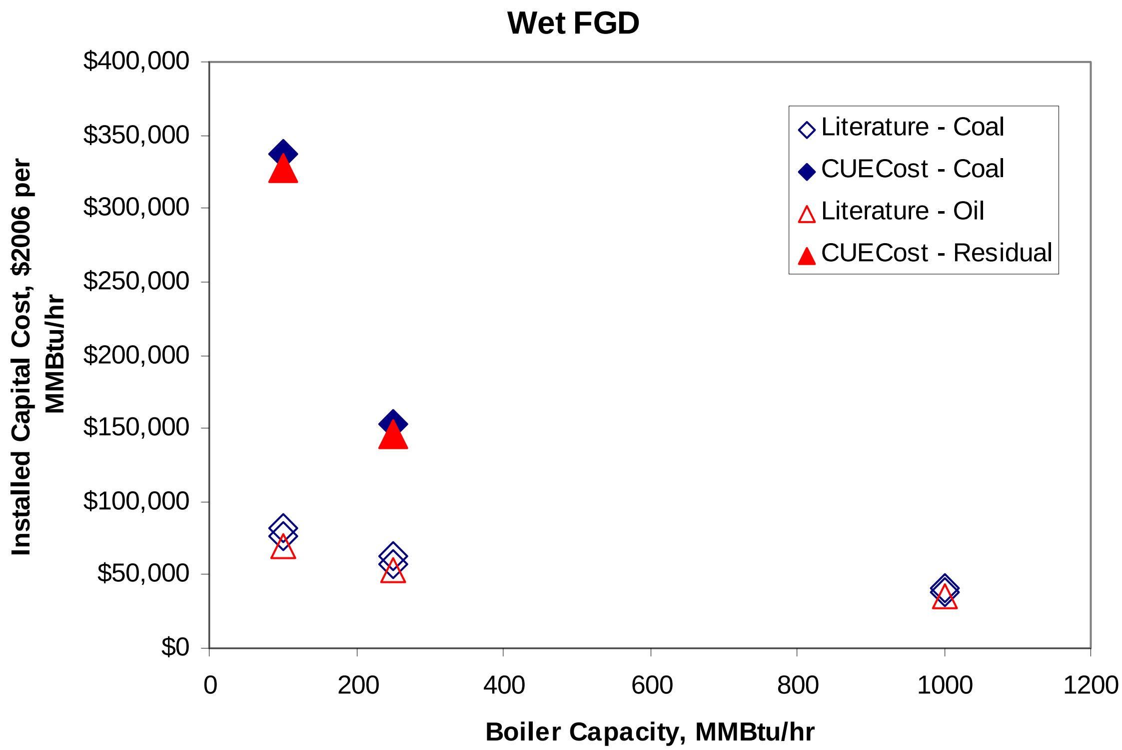

Figure 5-5. Comparison of CUECost-ICI model and reported literature values for capital cost of wet FGD for SO_2 control

Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to ICI boilers [US EPA, 2003a; US EPA, 2003b]. In these references, the capital costs were given in terms of dollars/scfm (2002$). These costs were converted to dollars per MMBtu/hr using the flow rates in *Table 5-3* and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values. Chapter Four contains a detailed discussion of the literature values for PM control costs.

The dry ESP control costs computed with CUECost-ICI were consistent with the literature values, although the CUECost-ICI predicted slightly higher values than reported by EPA for dry, wire-plate ESPs [US EPA, 2003a]. Note that a size was not given in the EPA cost-estimate. The FF costs computed with CUECost-ICI were higher than the literature values for pulse-jet fabric filters [US EPA 2003b].

5.3 Summary

An existing EPA model for estimating costs of selected control technology for NOx, SO_2, and PM for coal-fired EGU boilers greater than 1,000 MMBtu/hr was adapted for ICI boilers. Inputs were modified to allow a wider variety of fuels and to express boiler capacity in MMBtu/hr instead of MW. Modification of the correlations used for the coal-fired EGU model to calculate capital and operating costs for ICI boilers was outside the scope of this work. The new model, CUECost-ICI provided good agreement with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers. The resulting model provided a quick and flexible means to estimate capital and operating costs of

specific control technologies as applied to ICI boilers. Further detailed and extensive work will be needed to validate and refine the model's calculation framework for ICI boilers, and to add other APCD technologies to the model.

5.4 Chapter 5 References

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6 SUMMARY

ICI boilers are a significant source of NO_x, SO_2, and PM emissions, and are relatively uncontrolled, compared to EGUs. More than half of the surveyed ICI boilers in the Northeast have no controls, approximately one-third have PM controls, very few units have NOx controls, and no units have SO_2 controls.

There are a range of technology options for cost-effectively reducing emissions of NOx, SO_2, and PM emissions from ICI boilers in the U.S. Operating costs may differ for ICI boilers than utility boilers, primarily because of their size and location. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs as a percentage of total capital cost than do utility boilers. While ICI boilers often have cost constraints due to their sizes and diversity of plant layout and settings, these factors also provide opportunities for low-cost applications. It is critical to conduct site-specific suitability analyses to assess performance potential or retrofit feasibility, and match the appropriate emission control technology for specific applications given boiler size, fuel type/quality, duty-cycle, and design characteristics.

This study adapted the CUECost model -- initially developed by EPA to estimate costs of selected control technology for NOx, SO_2, and PM for large coal-fired EGU boilers -- to assess ICI boiler control costs. The modeling results were consistent with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers.

6.1 NOx Controls

Most of the commercially available NOx control technologies used extensively in EGUs may also apply to ICI boilers. Some technologies have potential to capture mercury from the flue gas. Employing a combination of technologies can be more effective in reducing emissions than a stand-alone technology. While most of these technologies can be used together, some combinations may be more cost-effective. This should be assessed on a site- and strategy-specific basis. Options include:

- *Boiler Tuning or Optimization*, which can yield reductions of five to 15 percent or more;
- *Low-NOx Burner (LNB) and Overfire Air (OFA)*, which can be used separately or as a system, and can reduce NOx emissions by 40 to 60 percent. LNBs are applicable to most ICI boiler types, and are being increasingly used at ICI boilers less than 10 MMBtu/hr. These technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility.
- *Ultra Low-NOx Burners (ULNB)*, which can achieve NOx emission levels on the order of single digits in ppm.
- *Reburn*, which has been used only in large EGU applications, but is an option for larger watertube-type boilers, including stokers. It requires appropriate technical and economic analyses to determine suitability. Reburn may yield 35 to 60 percent reductions in NOx emissions.
- *Selective Catalytic Reduction (SCR)*, which can achieve reductions higher than 90 percent.

- *Selective Non-Catalytic Reduction* (*SNCR),* which can achieve between a 30 to 60 percent reduction in NOx.
- *Regenerative Selective Catalytic Reduction (RSCR^{TM})*, which is able to reduce NOx by 60 to 75 percent and CO by about 50 percent. These systems allow efficient use of an SCR downstream of a particulate control device, where the flue gas typically has a lower temperature than what is required for a conventional SCR. Such conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the exception of reburn. SNCR and SCR impose some degree of energy demand on the host boiler, including pressure, compressor, vaporization, and steam losses.

Most estimates for ICI boilers indicate capital costs in the range of $1,000 to $6,000 per MMBtu/hr and $1,000 to $7,000 per ton of NOx removed. LNBs and SNCR costs range from $1,000 to $3,000 per ton. For SCR, costs are between $2,000 and $14,000 per ton. SCR and SNCR costs are driven primarily by the consumption of the chemical reagent.

6.2 SO_2 Controls

ICI boilers firing coal are good candidates for employing SO_2 control technologies. Options include:

- *Flue Gas Desulfurization (FGD) or Scrubbers.* These technologies are commercially available, and have been used extensively on EGUs since the 1970s. *Wet scrubbers* (Wet FGD) are the predominant SO_2 control technology currently in use for EGUs, and are typically associated with high-sulfur applications. *Dry scrubbers* include Spray Dryers (SD) and Dry Sorbent Injection (DSI) technologies, and are more compatible with low- to medium-sulfur coals. Some dry scrubber systems can remove 20 to 60 percent of the SO_2, and in some cases up to 90 to 99 percent for HCl and SO_3. DSI technologies are currently being demonstrated on ICI boilers. Furnace Sorbent Injection systems used on cement plants are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent. For SDs, cost per ton of SO_2 removed was in the range of $1,600 to $5,000. Costs were between $1,900 and $3,800 per ton of SO_2 for wet FGDs. While the SO_2 capital costs computed with CUECost for SDs were consistent with the literature at 250 MMBtu/hr, the capital costs computed for wet FGDs were high compared to values reported in the literature.
- *Fuel switching*. While not a control technology *per se*, the emission reduction benefits of fuel switching are directly proportional to the difference in sulfur contents of the fuels. Fuel switching requires considerable cost and operational analyses. In the NESCAUM region, residual oil is commonly used in ICI boilers. Switching from a 3 to a 1 percent sulfur residual oil can provide cost-effective SO_2 reductions at about $771 per ton of SO_2 removed. For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2, as well as in $PM_{2.5}$. The cost of switching to distillate oil is estimated to be much higher than for residual oil, because the higher cost of distillate oil.

6.3 PM Controls

ICI boilers burn a variety of fuels that contain fly ash and thus emit PM. PM control technologies have been commercially available and widely used in EGU boilers for many years. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired boilers. They are very effective in removing total PM and $PM_{2.5}$, with most options removing greater than 99 percent. The options include: (1) *fabric filters or baghouses*; (2) *wet and dry electrostatic precipitators (ESPs)*; (3) *venturi scrubbers*; (4) *cyclones*; and (5) *core separators*. Control technology decisions should be made on a case-by-case basis that accounts for technical, economic, and regulatory considerations. Fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM removed for coal and up to $15,000 per ton of PM removed for oil. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can have a larger parasitic consumption – up to 10 kW/1000 acfm or higher.

APPENDIX A: Survey of Title V Permits in NESCAUM Region

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Solutia Incorporated	MA	Foster Wheeler	249	Coal (Bit. 0.7%S)	-	0.027	baghouse (Carborundum Environmental Systems)	1.2	-	0.525	OFA (Foster wheeler)	-
St. Gobain Abrasives	MA	Riley	230	Coal (Subbit. 0.63%S)	-	0.1	Dust Collector	1.1	-	0.45	LNB	-
UMASS Amherst	MA	Union Iron Works	80	Coal	-	0.12	baghouse	1.1	-	0.43	-	Convert to CHP No. 2 (9/07)
Cooley Dickinson Hospital	MA	Early 1980s	-	Wood	-	-	-	0.008	-	0.16	-	-
Cooley Dickinson Hospital	MA	2006/ AFS Energy Systems	29.88	Wood	-	0.01	Cyclone, Baghouse	0.025	-	0.15	FGR	-
Seaman Paper	MA	2006/ Hurst Boiler	29.88	Wood	-	0.01	Baghouse	0.025	-	0.15	FGR	-

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Cornell University	NY	-	248	Coal	-	0.3	Fabric Filter	Coal 1% S by weight	-	0.4	-	
Cornell University	NY	-	117	Coal	-	0.35	Fabric Filter	Coal 1% S by weight	-	0.4	-	-
Commonwealth Plywood	NY	-	16	Wood	-	-	Multi-Cyclone w/o Fly ash injection	-	-	-	-	-
Crawford Furniture	NY	-	6	Wood	-	-	Single Cyclone	-	-	-	-	-
Deferiet Paper Company	NY	1945/ Combustion Engineering	190	Coal	-	0.46	Multi-Cyclone w/o Fly ash injection, and wet Venturi scrubber	2.5	-	0.5	-	-
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 13

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 14
Eastman Kodak	NY	-	478	Coal (Bit.)	#2 Oil	0.26	ESP	-	-	-	-	Boiler # 15
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 41
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 42
Eastman Kodak	NY	-	640	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 43
Eastman Kodak	NY	-	705	Coal (Bit.)	#2 Oil	0.035	ESP	.6 (coal)	-	0.42	-	Boiler # 44

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Gunlocke Co.	NY	E. Keeler	18	Wood	Oil #2	0.53	Fly Ash Cyclone	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	14.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	41.54	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	27.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Lyonsdale Biomass	NY	Zurn	290	Wood	-	0.1	-	-	-	0.2	-	
Morton International	NY	-	138	Coal	-	0.34	Fabric Filter, ESP	1.7	-	0.5	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
SUNY at Binghamton	NY	International Boiler Works	100	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	X3
SUNY at Binghamton	NY	International Boiler Works	50	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	
US Salt - Watkins Glen Refinery	NY	2000?	160	Coal and/or Wood	NG and/or Coal, Wood	0.051	Fabric Filter	1.2	-	0.18	SNCR	
Dirigo Paper	VT	1977	180	Wood	-	0.20 gr/dscf	multiclone	-	-	0.3	none	-
Ethan Allen	VT	1950	59.5	Wood	-	0.45 gr/dscf	multiclone	-	-	1.94lb/ton wet wood 7.45lb/ton dry wood	none	-
Fraser	NH	1981, Zurn	324	Wood/Bark/Paper	# 6 Oil	0.1	Multi-cyclone + Venturi scrubber	0.8	-	0.25	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Tillotson Rubber	NH	1978	41	Wood	-	0.43	Multi-cyclone	-	-	-	-	
Allen Rogers Limited	NH		5	Wood								
Allen Rogers Limited	NH		5	Wood								
Forest Products Processing Center	NH		47	Wood								
Madison Lumber Mill	NH		13	Wood								
Chick Packaging	NH		10	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Ossipee Mountain Land Company	NH		4	Wood								
Ossipee Mountain Land Company	NH		4	Wood								
Tommila Brothers	NH		11	Wood								
Monadnock Forest Products	NH		30	Wood								
Whitney Brothers Company	NH		2	Wood								
HG Wood Industries	NH		9	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Design Contempo	NH		19	Wood								
Design Contempo	NH		13	Wood								
Solon Manufacturing	NH		9	Wood								
Rochester Shoe Tree/Ashland	NH		4	Wood								
Precision Lumber	NH		9	Wood								
King Forest Industries - Wentworth	NH		29	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Peterboro Basket Company	NH		3	Wood								
Souhegan Wood Products	NH		8	Wood								
Souhegan Wood Products	NH		1	Wood								
Souhegan Wood Products	NH		1	Wood								
Concord Steam Corporation	NH		40	Wood								
Concord Steam Corporation	NH		40	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Boyce Highlands	NH		4	Wood								
Herrick Millwork	NH		5	Wood								
Northland Forest Products	NH		5	Wood								
Anthony Galluzzo Corporation	NH		4	Wood								
Cousineau Wood Products	NH		14	Wood								
Newport Mills Inc	NH		6	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Newport Mills Inc	NH		6	Wood								
Catamount Pellet Corporation	NH		40	Wood								
Durgin & Crowell Lumber Company	NH		10	Wood								
GH Evarts & Company	NH		7	Wood								

References: State Title V Permits, Coal SO_2 Database, ICI Coal Database, MA ICI 100-250 Boiler Database, VT ICI Boiler Database

APPENDIX B: CUECost-ICI Inputs

INPUTS

Description	Units	Input 1	Input 2	Input 3	Input 4	Input 5
General Plant Technical Inputs						
Location - State	Abbrev.	PA	PA	PA	PA	PA
Combustion Configuration	Abbrev.	PC	PC	PC	PC	PC
MW Equivalent of Flue Gas to Control System	MW	25	25.1	28.6	28.6	32.9
Net Plant Heat Rate	Btu/kWhr	10,000	11,370	8,750	8,750	7,600
Plant Capacity Factor	%	66%	66%	66%	66%	66%
Total Air Downstream of Economizer	%	154%	169%	118%	118%	119%
Air Heater Leakage	%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350	350	350	350
Inlet Air Temperature	°F	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013	0.013
Ash Split:						
Fly Ash	%	85%	85%	85%	85%	85%
Bottom Ash	%	15%	15%	15%	15%	15%
Seismic Zone	Integer	1.0	1.0	1.0	1.0	1.0
Retrofit Factor	Integer	1.0	1.0	1.0	1.0	1.0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	2	3	4	5	6
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No	No
Economic Inputs						
Cost Basis -Year Dollars	Year	2006	2006	2006	2006	2006
Service Life (levelization period)	Years	15	15	15	15	15
Inflation Rate	%	3%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	8%	8%	8%	8%	8%
AFDC Rate (current $'s)	%	8%	8%	8%	8%	8%
First-year Carrying Charge (current $'s)	%	22%	22%	22%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%	17%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%	16%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%	12%	12%	12%
Sales Tax	%	6%	6%	6%	6%	6%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	3%	3%	3%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	478.7	478.7	478.7	478.7	478.7
If "No" input escalation rate.	%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%	3%

Operating Labor Rate	$/hr	$25	$25	$25	$25	$25
Power Cost	Mills/kWh	47	47	47	47	47
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs

SO_2 Removal Required	%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2	2
(1 = yes, 2 = no)						
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Reagent Feed Ratio	Factor	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO_2 removed)						
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)						
Number of Absorbers	Integer	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Absorber Pressure Drop	in. H2O	6	6	6	6	6
Reheat Required ?	Integer	1	1	1	1	1
(1 = yes, 2 = no)						
Amount of Reheat	°F	25	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton	$25	$25	$25	$25	$25
Stacking Disposal Cost	$/ton	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO_2 Removal Required	%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147	147
Reagent Feed Ratio	Factor	0.90	0.90	0.90	0.90	0.90
(Mole CaO / Mole Inlet SO_2)						
Recycle Rate	Factor	30	30	30	30	30
(lb recycle / lb lime feed)						
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Spray Dryer Pressure Drop	in. H2O	5	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$60	$60	$60	$60	$60
Dry Waste Disposal Cost	$/ton	$25	$25	$25	$25	$25
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Particulate Control Inputs

Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.03	0.01	0.01	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	6	6	6
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2	2
Gas-to-Cloth Ratio	acfm/ft^2	5.5	5.5	5.5	5.5	5.5
Bag Material (RGFF fiberglass only)	Integer	1	1	1	1	1
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)						
Bag Diameter	inches	6	6	6	6	6
Bag Length	feet	20	20	20	20	20
Bag Reach		3	3	3	3	3
Compartments Out of Service	%	10%	10%	10%	10%	10%
Bag Life	Years	2	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
ESP:						
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0	10.0	10.0
Plate Spacing	in.	12	12	12	12	12
Plate Height	ft.	36	36	36	36	36
Pressure Drop	in. H2O	3	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOx Stoichiometric Ratio	NH3/NOx	0.9	0.9	0.9	0.9	0.9
NOx Reduction Efficiency	Fraction	0.70	0.70	0.70	0.70	0.70
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.4
Space Velocity (Calculated if zero)	1/hr	3000	3000	11800	11800	16800
Overall Catalyst Life	years	4	4	4	4	4
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Catalyst Cost	$/ft3	356.34	356.34	356.34	356.34	356.34
Solid Waste Disposal Cost	$/ton	25.38	25.38	25.38	25.38	25.38
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
Number of Reactors	integer	1	1	1	1	1
Number of Air Preheaters	integer	1	1	1	1	1

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	1:Urea 2:Ammonia	1	1	1	1	1
Number of Injector Levels	integer	3	3	3	3	3
Number of Injectors	integer	18	18	18	18	18
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1	1	1
NOx Reduction Efficiency	Fraction	0.50	0.50	0.50	0.50	0.50
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.2
NH3/NOx Stoichiometric Ratio	NH3/NOx	1.2	1.2	1.2	1.2	1.2
Urea/NOx Stoichiometric Ratio	Urea/NOx	1.2	1.2	1.2	1.2	1.2
Urea Cost	$/ton	200	200	200	200	200
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Water Cost	$/1,000 gal	0.22	0.22	0.22	0.22	0.22
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Low-NOx Burner Technology Inputs

NOx Reduction Efficiency	fraction	0.40	0.40	0.40	0.40	0.40
Boiler Type	T:T-fired, W:Wall	W	W	W	W	W
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%

Natural Gas Reburning Inputs

NOx Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	4.24	4.24	4.24	4.24	4.24
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-90-016
August 1990

Air

EPA

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

EPA-450/3-90-016

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1990

2.3.3 Percent Reduction Standard

1. Comment: Two commenters (IV-D-08, IV-D-28) requested that the 90 percent SO_2 reduction requirement be eliminated and replaced with an emission limit of 520 ng/J (1.2 lb/million Btu) heat input. One commenter (IV-D-08) objected to applying the 90 percent SO_2 reduction requirement to all coal regardless of sulfur content. This commenter stated that the EPA's conclusion that no units will be built in the size range between 22 and 29 MW (75 and 100 million Btu/hr) heat input capacity and operating at greater than 55 percent capacity factor is flawed. This commenter stated that the SO_2 standard of 520 ng/J (1.2 lb/million Btu) heat input for coal-fired plants should apply to all steam generating units in this source category, regardless of size. This commenter further recommended that the full 90 percent SO_2 removal be required only when the 520 ng/J (1.2 lb/million Btu) limit could not be met by using low sulfur coals or by pretreating the coals.

Another commenter (IV-D-28) stated that the 90 percent SO_2 reduction requirement should be removed and that coal-fired steam generating units in the 8.7 to 29 MW (30 to 100 million Btu/hr) range should be required only to meet the 520 ng/J (1.2 lb/million Btu) SO_2 limit. The commenter stated that the percent reduction requirement would place an unjustified cost and performance burden on units in this range that either already meet or are close to meeting the 520 ng/J (1.2 lb/million Btu) SO_2 limit.

Response: Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the

Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable. As discussed in the background document, "Model Boiler Cost Analysis for Controlling Sulfur Dioxide (SO_2) Emissions from Small Steam Generating Units" (EPA-450/3-89-14), a small coal-fired steam generating unit of 22 MW (75 million Btu/hr) size and operating at a 55 percent capacity factor has an incremental cost-effectiveness value of about $3,600/Mg ($3,300/ton) relative to an emission limit standard of 520 ng/J (1.2 lb/million Btu). Capital and annualized costs are projected to increase by approximately 20 percent over the regulatory baseline for the percent reductions standard. However, these values increase significantly for units less than 22 MW (75 million Btu/hr) heat input capacity and for any unit less than 29 MW (100 million Btu/hr) operating at an annual capacity factor for coal of less than 55 percent. Imposing these high costs for these units was considered to be unreasonable when compared to the increase in emission reductions achievable by the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less.

Finally, no conclusion was made that coal-fired steam generating units greater than 22 MW (75 million Btu/hr) heat input and greater than 55 percent capacity factor would not be built. Rather, this was a projection of sales over the next five years based on sales trends over the past several years. The sales projections for coal-fired units had no influence on the conclusion of the reasonableness of the percent reduction requirement. (The assumption was used in generating national impacts of the standards.) The model steam generating unit analysis examined the potential impacts of the percent reduction requirement on a coal-fired unit greater than 22 MW (75 million Btu/hr) and greater than 55 percent capacity factor. Therefore, should a unit be built, requiring 90 percent reduction of emissions would be reasonable.

UFC 3-701-01
23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

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23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

Indicate the preparing activity beside the Service responsible for preparing the document.

U.S. ARMY CORPS OF ENGINEERS

NAVAL FACILITIES ENGINEERING COMMAND (Preparing Activity)

AIR FORCE CIVIL ENGINEER CENTER

Record of Changes (changes are indicated by **\1** ... **/1/**)

Change No.	**Date**	**Location**
1	6-25-18	Update Table 3 with RUC. Text update 3-2.

This UFC supersedes UFC 3-701-01, dated March 2011.

FOREWORD

The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with USD (AT&L) Memorandum dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of Forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the most stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Center (AFCEC) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: Criteria Change Request. The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site http://dod.wbdg.org/.

Refer to UFC 1-200-01, *DoD Building Code (General Building Requirements)*, for implementation of new issuances on projects.

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UNIFIED FACILITIES CRITERIA (UFC)
[REVISION] SUMMARY SHEET

Document: UFC 3-701-01, *DoD Facilities Pricing Guide*

Superseding: UFC 3-701-01, dated March 2011

Description: The document provides updated cost and pricing data in support of facility planning, investment and analysis needs.

Reasons for Document:

- This UFC provides updated cost and pricing data intended to support preparation of the DoD budget.

Impact:

- Provides consistency across the DoD for the development of budgets for military construction projects.

Unification Issues

None

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CHAPTER 1 INTRODUCTION

1-1 PURPOSE AND SCOPE.

The DoD Facilities Pricing Guide supports a spectrum of facility planning, investment, and analysis needs. This version of the Guide reflects updated cost and pricing data for FY 2018 intended to support preparation of the DoD budget for FY 2020. It includes reference information organized into three chapters, as follows:

1-1.1 Chapter 2: Unit Costs for Military Construction Projects.

Chapter 2 describes the usage of facility unit cost data for selected DoD facility types in support of preparing Military Construction (MILCON) project documentation (DD Forms 1391) and other program-level estimates in accordance with UFC 3-730-01, "Programming Cost Estimates for Military Construction."

1-1.2 Chapter 3: Unit Costs for DoD Facilities Cost Models.

Chapter 3 describes the usage of unit costs in support of DoD facilities cost models. These unit costs are based upon the reported average DoD facility size or an established benchmark size, as annotated for each Facility Analysis Category (FAC) in the DoD Real Property Classification System (published separately). These unit costs are intended for macro-level analysis and planning rather than individual facilities or projects.

1-1.3 Chapter 4: Cost Adjustment Factors.

Chapter 4 describes the usage of cost adjustment factors for location and price escalation that are applicable to the base unit costs in both Chapters 2 and 3.

1-2 APPLICABILITY.

This UFC applies to all projects in both the continental US (CONUS) and outside the continental US (OCONUS).

1-3 DATA TABLES.

All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site:
https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

1-4 PROPONENT.

The Office of the Assistant Secretary of Defense for Energy, Installations, and Environment is the proponent for the Facilities Pricing Guide. Recommendations from users toward improving the usefulness of this reference are welcome.

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CHAPTER 2 UNIT COSTS FOR MILITARY CONSTRUCTION PROJECTS

2-1 OVERVIEW.

The facility unit costs in this chapter apply to preparation of programming-level cost estimates for constructing military facilities in accordance with the methodology described in UFC 3-730-01.

All data tables in this UFC are found under "Related Materials" in a combined file accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

2-2 FACILITY UNIT COST TABLE.

Table 2 provides facility unit costs for various DoD facility types in dollars per square meter ($/SM) and equivalent English unit cost data in dollars per square foot ($/SF) as of October 2017. The listed facility types represent only those facilities most frequently constructed by the Military Services, and the application of a facility unit cost may not be directly applicable for those facilities with unique requirements. See UFC 3-730-01 for additional guidance on facility unit costs and their application.

The unit costs in Table 2 are average unit costs for new construction based on no less than three project awards per building type occurring since September 2014 for Army, Navy, Air Force, Defense Education Activities (for school projects) and Defense Health Agency (for medical projects) facilities as entered into the Historical Analysis Generator (HII) unit cost database prior to 1 Nov 2017. Facility additions which are less than 25% of the Reference Size of the listed facility type, and projects outside of the continental United States (OCONUS), are included only for Family Housing and DoD Schools. For additional information regarding how the facility unit costs are determined, refer to paragraph 2-3, Guidance Unit Cost Development.

2-3 GUIDANCE UNIT COST (GUC) DEVELOPMENT METHODOLOGY.

2-3.1 Data Source.

The data source for the facility unit costs is all reliable HII project records, after excluding records for reasons stated in paragraph 2-2. In general, all project records for the CONUS and projects from Alaska and Hawaii are included.

Facility level information from all three Services projects is entered into HII database for comparable service category codes (CATCODEs). Normalized project unit costs are statistically analyzed to eliminate outliers before calculating the guidance unit cost (GUC).

2-3.2 Business Rules.

The business rules are reviewed annually prior to updating Table 2 Facility Unit Costs for Military Construction. The business rules include the following components.

- The Tri-Service CATCODEs Cross-walk table groups like service CATCODEs to a common Office of the Secretary of Defense (OSD) Code. OSD Codes are not published and are only utilized for this task of segregating data. A minimum of three projects are required within those defined years to create a dataset. If there is insufficient data available within the above three-year period, the dataset search is extended to the last four years.
- Projects are new construction only.
- Projects are located within the CONUS, plus Hawaii and Alaska, except where noted otherwise in Table 2.
- Projects with extreme variation from the mean (50%) are excluded., and
- Exclusion of inappropriate data for cause.

2-3.3 Data Normalization.

Each facility-specific data set is normalized to the National Average Area Cost Factor (ACF=1) and number of bidders, and escalated to October of the year of interest, before unit costs are averaged.

- Escalation: The DoD Selling Price Index (DoD-SPI), which is an average of three commonly accepted national construction price escalation indices, is utilized to escalate actual project award cost data to October of 2017 for this UFC,
- Number of Bidders: Based on actual bid data for the data set,
- Location: Normalize each project award by the appropriate ACF to the national average of 1.0, and
- Facility Size: Normalize each facility award amount in the dataset for facility size, using a normalization process that looks at the facility size as compared to the average facility size of the selected dataset by OSD code.

2-3.4 Primary Facility Included Costs.

The facility unit costs include the following:

- Minimum antiterrorism design features (reference UFC 4-010-01, “DoD Minimum Antiterrorism Standards for Buildings”) inside the building meeting Table B-1 standoff distance requirements,
- Sales tax on building materials,

- Building information system costs (e.g., conduits, racks, trays, telecommunication rooms) without any specialized communications requirements,
- Installed (built-in) building equipment and furnishings normally funded with MILCON funds,
- Energy Management Control System (EMCS) connections,
- Intrusion Detection System (IDS) infrastructure, including conduits, racks, and trays,
- Sustainable design and construction features - energy consumption reduction requirements mandated before 6 November 2016; and all other sustainable design features for criteria in effect from September 2014 thru September 2017 with the exception of renewable energy generation elements,
- Progressive Collapse premiums for the following specific facility types: Inpatient Hospital/Medical Center, Primary Care Clinic (Attached), Major Command Headquarters Building, Barracks/Dormitory, and Recruit Open Bay (Barracks), and
- Standard foundation systems (e.g. strip/spread footings, thickened edge slab for slab on grade).

2-3.5 Primary Facility Excluded Costs.

The unit costs do not include the following:

- Gross receipt taxes or gross taxes, gross excise taxes, or state commerce taxes,
- “Acts of God” or unusual market conditions,
- Supporting facility costs,
- Equipment acquired with other fund sources, including pre-wired workstations or furnishing systems, intrusion detection systems,
- Sustainable design and construction features - renewable energy generation elements; energy consumption reduction requirements mandated on or after 6 November 2016; and all other features mandated since September 2017; these will be estimated separately in accordance with component guidelines and documented on DD Form 1391 per DoD Instruction 4170.11, Installation Energy Management,
- Special foundations (e.g. pre-stressed concrete piles, caissons), intrusion detection system installation, base exterior architectural preservation guidelines,

- Enhanced Anti-Terrorism (AT) standards (exceeding the minimum in UFC 4-010-01, or when minimum standoff distances [Table B-1] are not achieved) construction contingency allowances,
- Cybersecurity costs,
- Supervision, inspection, and overhead (SIOH),
- Design costs (design-build contracts), and Construction cost growth resulting from user changes, unforeseen site conditions, or contract document errors and omissions.

2-3.6 Primary Facility Cost Considerations.

The following are cost considerations for primary facilities:

- Medical facilities: Unit costs include category A and category B equipment and building infrastructure for category C equipment,
- Housing for Unaccompanied Military Personnel: Unit costs for barracks, dormitories, and Unaccompanied Officers Quarters do not include free-standing kitchen equipment. In addition to using the size adjustment factors, use the project size adjustment factors in UFC 3-730-01,
- Child Development Centers: Unit costs do not include free-standing food service equipment or playground area and equipment,
- Family housing: Unit costs are based upon gross area and include sprinkler systems or fire-rated construction. Unit costs include post-award design costs,
- Reserve facilities other than reserve centers: Use the unit cost of the appropriate facility type, and
- Costs are independent of the acquisition strategy and are not specific to any single construction type.

CHAPTER 3 UNIT COSTS FOR DOD FACILITIES COST MODELS

3-1 OVERVIEW.

This chapter describes the unit costs and related factors used in support of DoD facilities cost models. These unit costs are intended for macro-level analysis and planning and are not reliable for individual facilities or project estimates.

Unit costs and related factors are associated with FACs represented by a 4-digit code in the DoD Real Property Classification System (RPCS), which is a hierarchical scheme of real property types and functions that serves as the framework for identifying, categorizing, and modeling the DoD's inventory of land and facilities. FACs are common across the department and suitable for department-wide applications. For each FAC, Table 3 identifies the associated unit cost to be used in DoD facilities cost models and metrics.

Whenever possible, unit costs and factors have been based upon approved government or commercial benchmarks. Detailed supporting data for unit costs is available, and accompanies this UFC on the WBDG Web site. All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-2 REPLACEMENT UNIT COSTS (RUC).

3-2.1 \1\ Definition and Use of Replacement Unit Costs. /1/

\1\ Replacement unit costs form the basis of calculating Plant Replacement Value (PRV) in a consistent manner across DoD, representing a complete and useable facility built to current DoD design standards. Replacement unit costs can also support large-scale program-level estimates for re-stationing plans with the addition of allowance for site preparation, earthwork, landscaping, and related factors. Replacement unit costs should not be used for individual project estimates. /1/

Replacement \1\ unit /1/ costs include construction of standard foundations, all interior and exterior walls and doors, the roof, utilities out to the 5-foot line, all built-in plumbing and lighting fixtures, security and fire protection systems, electrical distribution, wall and floor coverings, heating and air conditioning systems, and elevators. Replacement \1\ unit /1/ costs do not include project costs such as design, supporting facility costs, special foundations, equipment acquired with other funding sources (e.g. mission-funded components), contingency costs, or supervision, inspection, and overhead (SIOH). \1\ unit /1/ costs also do not include items that are generally considered personal property such as computer systems, and furniture. See paragraph 3-5, Revising Unit Costs, for guidance on requesting changes \1\ to replacement unit costs /1/in Table 3.

3-2.2 \1\ Plant Replacement Value (PRV). /1/

DoDI 4165.14 defines PRV as the cost to design and construct a notional facility to current standards to replace an existing facility on the same site. The factor values are provided in the “Report of the Plant Replacement Value (PRV) Panel, August 2001-May 2003” published by the Office of the Deputy Under Secretary of Defense (Installations and Environment). The standard DoD formula for calculating PRV is:

Equation 3-2 Calculating PRV

PRV = Q x RUC x ACF x HF x PD x SIOH x CF

Where:

PRV is plant replacement value

Q is facility quantity, in the same unit of measure as the RUC

RUC is replacement unit cost found in Table 3 of this UFC

ACF is area cost factor found in Table 4 of this UFC, to account for geographical differences in the costs of labor, materials and equipment

HF is an adjustment of 1.05 to account for increased costs for replacement of historical facilities or for construction in a historic district. The factor is 1.0, should the facility not qualify as “historical”.

PD is a factor to account for the planning and design of a facility; the current value of this factor is 1.09 for all but medical facilities, and 1.13 for medical facilities.

SIOH is the factor to account for the supervision, inspection, and overhead activities associated with the management of a construction project. The current value of the factor is 1.057 for facilities in the (CONUS), and 1.065 (USACE) or 1.062 (NAVFAC) for facilities in the (OCONUS).

CF is a factor of 1.05 to account for construction contingencies

3-3 SUSTAINMENT UNIT COSTS (SUC).

3-3.1 Definition.

Sustainment provides for maintenance and repair activities necessary to keep a typical inventory of facilities in good working order over its expected service life. It includes the following:

- Regularly scheduled adjustments and inspections, including maintenance inspections (e.g., fire sprinkler heads, HVAC systems) and regulatory inspections (e.g., elevators, bridges),
- Preventive maintenance tasks,
- Emergency response and service calls for minor repairs, and
- Major repair or replacement of facility components (usually accomplished by contract) that are expected to occur periodically throughout the facility service life.

Sustainment includes regular roof replacement, refinishing wall surfaces, repairing and replacing electrical, heating, and cooling systems, replacing tile and carpeting and similar types of work as well as overhead costs which include architectural and engineering services. It does not include repairing or replacing non-attached equipment or furniture, or building components that typically last more than 50 years (such as foundations and structural members). Sustainment does not include restoration, modernization, environmental compliance, facility leases, specialized historical preservation, general facility condition inspections and assessments, planning and design (other than shop drawings), or costs related to Acts of God, which are funded elsewhere. Other tasks associated with facilities operations (such as custodial services, grass cutting, landscaping, waste disposal, and the provision of central utilities) are also not included.

3-3.2 Use of Sustainment Unit Costs.

Sustainment unit costs represent the annual average sustainment cost for each FAC, and serve as the basis for calculating annual facilities sustainment requirements for DoD using the following formula:

Equation 3-3 Calculating Sustainment Requirement

$$SR = Q \times SUC \times SACF \times I$$

Where:

SR is sustainment requirement

Q is facility quantity, in the same unit of measure as the SUC

SUC is sustainment unit cost found in Table 3

SACF is sustainment area cost factor found in Table 4

I is the value(s) representing future-year escalation for operation and maintenance accounts, published in Table 4-4.

The Sustainment Requirement for each qualifying asset in the DoD inventory is aggregated by sustaining organization and sustainment fund type in the Facilities Sustainment Model (FSM), published annually.

3-4 UNIT COST SOURCES.

Unit costs for DoD cost models are developed using a variety of sources. These sources fall into the three categories described below, listed in order of preference of use. The source description and source group for each unit cost are identified in Table 3. Supporting documentation for each unit cost calculation is available in the "Supporting documentation" file download accompanying this UFC document on the WBDG website: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-4.1 Source 1 Published Data

Standard, easily-accessible published data that is highly applicable to the FAC. Source 1 is the most desirable due to ease of access, general applicability, and lack of bias. Examples include the DoD Tri-Service Committee on Cost Engineering, Service-specific cost guidance (USACE), commercial cost-estimating guidelines or models, or other Government-published cost guidance from federal, state, or local government agencies (e.g. Fairfax County (Virginia) Park Authority). Non-DoD source 1 data may require refinement for application in DoD, but is still considered source 1 if it closely matches the design attributes of the FAC.

3-4.2 Source 2 Similar Data

Data that is applied to facilities with similar but not identical characteristics (e.g., sewage waste treatment facilities and industrial waste treatment facilities). Source 2 also includes unpublished government or trade association cost data, and Component-validated costs for non-standard facilities that have no commercial counterparts (e.g. missile launch facilities or military ranges).

3-4.3 Source 3 Derived Data

Unpublished project-specific data derived from Component project documents (e.g. DD Forms 1391) or from calculating costs from reported Plant Replacement Value and inventory, or derived from using a ratio of sustainment to construction from a similar source 1 Facilities Analysis Category (e.g. FAC 2115, Aircraft Maintenance Hangar, Depot derived from FAC 2111, Aircraft Maintenance Hangar).

3-5 REVISING UNIT COSTS.

Users of this UFC are encouraged to suggest revisions to the published cost factors, particularly for facilities unique to their mission. Submit proposed changes to the proponent office in accordance with the following guidelines:

- Revised costs should come from an equivalent or superior source,
- Revised costs should be easily audited,
- Revised costs should be consistent with the functional definitions,
- Revised costs should be consistent with the FAC scope and
- Revised costs should be suitable for application throughout DoD.

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CHAPTER 4 COST ADJUSTMENT FACTORS

4-1 LOCATION ADJUSTMENTS.

Table 4-1 provides area cost factors (ACFs) to be used for adjusting “bare” unit costs to location-specific costs for the most common locations.

All data tables in this UFC are found in a combined file under “Related Materials” accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

4-1.1 Application

For military construction projects, use the MILCON ACFs with the primary facility unit costs from Chapter 2 or approved Air Force, Army, or Navy MILCON Pricing Guide. For calculating Plant Replacement Value, use the MILCON ACFs with the appropriate RUCs from Chapter 3. For calculating sustainment costs, use the sustainment ACFs with the appropriate SUCs from Chapter 3.

Do not use the MILCON ACFs to modify parametric cost estimates, detailed quantity-take-offs, unit price book (UPB) line items, commercial cost data, or user-generated unit costs. These cost estimating methods and databases have their own processes and factors for adjusting costs to different locations. MILCON ACFs or any component(s) that make up MILCON ACFs are only applicable to construction costs and should not be applied or utilized for any other purpose.

4-1.2 Data Source

In general, the Tri-Service Cost Engineering ACF software program evaluates the local costs for a United States market basket of eight labor crafts, 18 construction materials, and four equipment items. These labor, materials, and equipment (LME) items are representative of the types of products, services, and methods used to construct most military facilities in the United States. Each of the LME costs is normalized and weighted to represent its contribution to the total cost of a typical facility. The normalized LME is then modified by seven matrix factors that cover local conditions affecting construction costs. These matrix factors include weather, seismic, climatic (frost zone, wind loads, and HVAC systems), labor availability, contractor overhead and profit, logistics, and labor productivity and are relative to the U.S. standard. The resultant ACF for each location is normalized again by dividing by the 96-Base-City average to provide a final ACF that reflects the relative relationship of construction costs between that location and the 96-Base-City average as 1.00.

MILCON ACFs are calculated using a LME ratio of 35/63/2. Sustainment ACFs are calculated using a LME ratio of 53/46/1.

4-1.3 Survey

Both CONUS and OCONUS construction market surveys were conducted in 2017. The CONUS survey covered 300 locations that included 96 Base Cities (two per state in the continental U.S.). The OCONUS survey included 75 locations, and was based on a market basket of goods for typical U.S. labor, material, equipment, and construction methods.

CONUS and OCONUS surveys are performed annually. When local materials and construction methods differ from those represented by the published ACF, specific adjustments may need to be added to the project estimate to account for any differences. There is no easy correlation between the current MILCON ACFs and previous MILCON ACFs for specific locations. No common benchmarks exist because both the Base City average and the relationships between cities change with each survey. It is possible, however, to compare differences between several locations in this database with differences between the same locations in previous databases.

4-1.4 Force Majeure

The ACF is not intended to, or capable of, responding to rapid changes in the market place. Examples include Acts of God, accelerated construction schedules, changes in the demand and supply for construction materials, labor, and equipment. An increased demand for labor beyond what the local market can supply may require the enticement of premium pay, overtime hours, temporary living expenses, and travel expenses.

4-1.5 User Requested Revisions

Users may request revisions to published ACFs when market conditions unexpectedly change. Each request must be initiated by the USACE District senior cost engineer through HQUSACE or by the NAVFAC regional cost engineer to their corresponding NAVFAC Atlantic or Pacific Tri-Service Cost Engineering committee member. The local cost engineer shall provide updated market basket ACF software input factors with adequate backup documentation to HQUSACE or NAVFAC for them to update the Tri-Service Cost Engineering ACF software.

4-2 ESCALATION.

Tables 4-2, 4-3, and 4-4 provide escalation (inflation) factors used to adjust unit costs in Tables 2 and 3 (expressed in base-year dollars) to the desired year, as follows:

4-2.1 Military Construction.

Military construction project estimates that use unit costs from Table 2 should use the military construction escalation factor from table 4-2 for the expected midpoint of construction as described in UFC 3-730-01.

4-2.2 Plant Replacement Value Escalation Rates.

Plant Replacement Value (PRV) calculations that use replacement unit costs from Table 3 should use the escalation factor from Table 4-3 for the desired program year.

4-2.3 Facilities Sustainment.

Modeled facilities sustainment cost estimates that use unit costs from Table 3 should use the O&M escalation factor from Table 4-4 for the desired program year.

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APPENDIX A REFERENCES

UNIFIED FACILITIES CRITERIA

http://www.wbdg.org/ccb/browse_cat.php?o=29&c=4

UFC 3-730-01, *Programming Cost Estimates for Military Construction*

PLANT REPLACEMENT VALUE

https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01

Report of the Plant Replacement Value (PRV) Panel, August 2001 – May 2003, R&K Engineering, Inc. for the Office of the Deputy Under Secretary of Defense (Installations and Environment)

Proposed BACT Alternative

November 19, 2018

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1.0 Introduction

The Fairbanks North Star Borough (FNSB) has levels of fine particulate matter ($PM_{2.5}$) that are above the health based National Ambient Air Quality Standard (NAAQS). In November 2009 the area was designated as a Moderate Nonattainment Area (NAA) based on monitoring data indicating the area did not meet the 2006 24-hour $PM_{2.5}$ standard. On April 28, 2017, the area was re-designated as a "Serious" NAA as a result of not attaining the $PM_{2.5}$ standard within 5-years from designation. As a result, the state is required to propose additional measures to bring the area into compliance within 10-years from designation (i.e., December 2019).

Once EPA re-classified the FNSB $PM_{2.5}$ nonattainment area to Serious, it triggered the requirement for stationary sources with over 70 tons per year (tpy) potential to emit (PTE) for $PM_{2.5}$ or its precursors (SO_2, NO_x, VOC, & NH_3) to conduct a Best Available Control Technology (BACT) analysis. Based on the Alaska Department of Environmental Conservation (ADEC) preliminary evaluations, sulfur dioxides are being evaluated for point source control measures under BACT. At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO2) control. Preliminary Determinations by ADEC suggest a capital cost to Aurora Energy, LLC (Aurora) for BACT compliance of $12,332,076 for an 80% removal efficiency using dry sorbent injection.

Aurora asserts that the proposed Best Available Control Technologies for sulfur dioxide emissions are not economically feasible. Confronted with this fact, ADEC and the EPA have asked Aurora to suggest an alternative to the ADEC proposed BACT. Within the context of this document Aurora is providing a proposal for alternative BACTs, all of which mitigate Aurora's impact to the nonattainment area problem.

The alternative BACTs proposed by Aurora provide meaningful solutions in offsetting the largest contributing factor to the $PM_{2.5}$ problem in Fairbanks: home heating. The alternative BACTs being proposed by Aurora are more efficient from a dollar per ton of pollutant removed than the ADEC proposed BACT. Aurora strongly believes that these alternatives can have a more positive impact to the air quality issue than the ADEC proposed BACT. Before implementing these alternative BACTs, Aurora needs ADEC and EPA to agree that these alternative BACTs satisfy Aurora's obligations for compliance with the NAA issue and that future controls to address $PM_{2.5}$ in the NAA will not be required.

Additionally, Aurora is making this alternative proposal based on the premise that ADEC and EPA will consider a precursor demonstration to determine the actual contribution of $PM_{2.5}$ by the point sources in the NAA. It has been stated repeatedly that the point sources are not the primary cause of the $PM_{2.5}$ problem. However there has never been a thorough analysis done to understand to what extent the point sources are or are not contributing to the problem. Should a precursor demonstration show that the point sources within the NAA are not major contributors to the $PM_{2.5}$ problem, all $PM_{2.5}$ compliance requirements imposed on the point sources shall be vacated. If however the precursor demonstration shows that the point sources are above the insignificance threshold, the alternative BACTs proposed by Aurora would satisfy the requirements for compliance within the NAA.

In closing, Aurora desires to be a part of the solution to reduce the $PM_{2.5}$ levels within the NAA. Aurora remains convinced that the ADEC proposed BACT is cost prohibitive and an inefficient use of funds. Instead Aurora is proposing alternative BACTs that directly help solve the PM2.5 problem. In proposing these alternatives, Aurora needs ADEC and the EPA to agree to continue to study the source of PM2.5

pollution as well as confirm that these alternative BACTs meet Aurora's compliance with the Clean Air Act for purposes of NAA attainment.

1.1 ADEC BACT Analysis

ADEC provided its review of a BACT analysis for Aurora which included an evaluation of technologies to mitigate emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form $PM_{2.5}$ in the atmosphere post combustion. The BACT analysis evaluated all available control options for equipment emitting the triggered pollutants and followed a process for selecting the best option based on feasibility, economics, energy, and other impacts. The results of the BACT analysis are reflected in Table 1.

Table 1: Department Economic Analysis for Technically Feasible NOx and SO_2 controls.

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 3,930,809.00	$ 957,728.00	$ 2,226.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 17,331,770.00	$ 2,787,995.00	$ 3,240.00
Dry Sorbent Injection (DSI)[2]	SO_2	$ 12,332,076.00	$ 4,284,104.00	$ 6,308.00
Spray Dry Absorber (SDA)[2]	SO_2	$ 60,270,115.00	$ 11,862,577.00	$ 15,525.00
Wet Scrubber (WS)[2]	SO_2	$ 65,957,875.00	$ 12,160,961.00	$ 14,469.00

1 - Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)

2 - Capital Recovery Factor = 0.1098 (7% interest rate for a 15 year equipment life)

1.2 Aurora BACT Analysis

The ADEC requested additional information concerning Aurora's BACT analysis in a letter dated September 13, 2018. One of the ADEC's request were that Aurora comment on the cost analysis spreadsheets developed by ADEC and provided with the Preliminary Draft SIP. Comments were made on the spreadsheets and submitted to the ADEC on November 1, 2018. Below (Table 2) are the results of Aurora's inputs considering EPA and ADEC's comments. Spreadsheets are included along with this proposal for review by the agencies. Several changes to the inputs are documented in the summary for the spreadsheet inputs (See Appendix A & B). In conjunction with the changes made to the spreadsheets, site-specific quote for SO_2 controls, namely Dry Sorbent Injection (DSI), was provided to the ADEC as requested and included as a parameter within the cost analysis spreadsheets for the referenced control technologies. The EPA is requiring that the cost analyses include a 30 year equipment life for the control technologies except SNCR which is evaluated for 20 year equipment life.

Table 2: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.1

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[2]	NOx	$ 6,208,948.00	$ 989,197.00	$ 3,107.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 2,921,054.00	$ 4,587.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,601,940.00	$ 8,423.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 51,115,267.00	$ 8,716,232.00	$ 12,408.00
Wet Scrubber (WS)[1,3]	SO_2	$ 56,318,290.00	$ 8,839,892.00	$ 11,440.00

1 – Capital Recovery Factor = 0.0669 (5.25% interest rate for a 30 year equipment life) [EPA requirement per comments]
2 – Capital Recovery Factor = 0.0820 (5.25% interest rate for a 20 year equipment life) [EPA requirement per comments]
3 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

Table 3 reflects another iteration (V.2) of Aurora's changes to the ADEC's spreadsheets. The results in Table 3 consider a lower emission rate for both SO_2 and NO_x based on 2011 source testing information and/or additional information. The SO_2 emission rate assumed by the state and Aurora has been 0.39 lbs/MMBtu. The coal analysis for feed coal during the test showed elevated sulfur content (0.18%) in comparison to the 5-year weighted average sulfur content from 2013-2017 (0.14 %). Using a conservative conversion from sulfur content (0.14%) to sulfur dioxide, the 5-year weighted average SO_2 emission rate would be 0.36 lbs/MMBtu. This conservative emission rate was used in the calculations to derive the cost effectiveness values in Table 2. The sulfur content during the source test conducted in 2011 (0.18%) when converted to a heat input emission rate considering total conversion of sulfur to SO_2 yields an emission factor of 0.48 lbs/MMBtu. The actual tested emission rate was 0.40 lbs/MMBtu. The emission rate for SO_2 was 83% of the maximum potential. This suggests there is 17% capture of sulfur compounds in the ash. As such, the emission rate derived and used in Table 3, considers a 17% capture of sulfur in the ash. The conversion of sulfur to SO_2 based on the 5-year weighted average sulfur content in coal and a 17% capture rate yields 0.30 lbs/MMBtu (0.36 lbs/MMBtu X 0.834 = 0.30 lbs/MMBtu). The results in Table 3 account for the current sulfur content in coal and the rate adjustment for sulfur capture fraction from the process based on a source test conducted in 2011.

Also accounted for in Table 3 is a more realistic equipment life expectancy for the facility and control equipment. It is not reasonable to consider a 30 year and 20 year life expectancy for the control equipment and the boilers. Considering the age of the Chena Power Plant, Units 1-3 are 50,000 lb/hr boilers that were installed in the early 1950s, and Unit 5 is a 200,000 lb/hr boiler which was installed in 1970. Units 1-3 are already +65 years and Unit 5 is +45 years old. A 30 year horizon should not be applicable to the Chena Power Plant. A 15 year equipment life is considered in the following cost effectiveness analysis (Table 3).

Table 3: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.2

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 6,208,948.00	$ 1,088,694.00	$ 3,419.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 3,721,132.00	$ 5,844.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,914,480.00	$ 10,785.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 50,880,540.00	$ 10,084,456.00	$ 17,213.00
Wet Scrubber (WS)[1,2]	SO_2	$ 56,318,290.00	$ 10,314,589.00	$ 16,005.00

1 – Capital Recovery Factor = 0.0980 (5.25% interest rate for a 15 year equipment life)
2 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

2.0 Economic Infeasibility

The BACT review process as outlined by EPA includes five-step approach to determine the best control option. The economic feasibility of potential measures are addressed under Step 4 of the review process. Since there is no cost threshold for economic feasibility for controls within a serious nonattainment area, a source has to make the assertion to the regulatory agencies in order for economic infeasibility to be considered. Aurora's BACT results, as illustrated in Table 3, show that the least expensive SO_2 control technology is a $20 million dollar investment and the cost effectiveness value is above $10,000/ton of SO_2 removed.

Therefore, per the fine particulate implementation guidance, if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology demonstrated to be economically feasible, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators to the extent applicable:[1]

1. Fixed and variable production costs;
2. Product supply and demand elasticity;
3. Product prices (cost absorption vs. cost pass-through);
4. Expected costs incurred by competitors;
5. Company Profits;
6. Employment costs;
7. Other costs (e.g., for BACM implemented by public sector entities).

At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO_2) control. ADEC's preliminary determination suggests Aurora invest $12,332,076 for DSI technology to remove 80% of the SO_2 emissions from the Chena Power Plant. ADEC estimates that annualized costs for the application would be $4,284,104. ADEC's projected capital cost for retrofit SO_2 control technology is just above half of the costs of a +50/-30 design (e.g., capital cost $20,682,000) which was recently submitted to the ADEC. Even if the lower cost for controls estimated by the ADEC were valid, it is not economically feasible and therefore should not be required. Further, ADEC does not know whether the installation of DSI or any control technology on stationary sources will have a significant impact on the overall air quality in the non-attainment area.

Aurora has one electric customer and approximately 200 district heating customers. Income from power production is from wholesale electric sales to the local electrical cooperative, Golden Valley Electrical Association (GVEA). Aurora has a long term contract with GVEA which would be difficult to renegotiate for necessary price increases to accommodate additional control technologies. Pass-through cost opportunities for Aurora's district heating are not viable. The necessary product price increases to cover additional costs of the proposed control technology would price Aurora out of the market for both heat and power. The result would be higher electric and heat costs, coupled with an increase in $PM_{2.5}$ pollution due to the introduction of ground-level emissions from oil and/or gas fired furnaces and boilers that would be installed to replace uneconomic district heat. As Aurora customers switch to less expensive fossil fuels – or yet even less expensive wood – the resulting burden on Aurora's remaining customers will increase, causing more and more of them to switch, resulting in a continuous increase in particulate emissions in the Fairbanks core, and in a death spiral for Aurora as an economically viable business. Within this section, Aurora will address the financial indicators applicable to demonstrate the economic infeasibility of installing and operating ADEC's proposed control technology.

1. Production Costs

Aurora's five year operating costs for electric and district heating (RCA) are provided below in Table 4. Operating costs consist of operations expense, maintenance expense, administrative expenses, and depreciation expense. The net operating costs for power generation was $0.08/kW in 2017 (Table 4). The

[1] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085.

margin for income is small as reflected in Table 6. District heating operating costs exceed income generated resulting in a net loss over the past 5 years (Table 6). [2]

Table 4: Aurora Energy Operating Costs

Year	Electrical Total	Net kWh	$/kWh	District heating Total	Net MMBtu	$/MMBtu
2017	$13,795,480	181,113,600	$0.08	$4,658,655	262,189	$17.77
2016	$13,707,259	189,093,610	$0.07	$5,285,399	249,151	$21.21
2015	$12,582,952	194,083,220	$0.06	$5,395,212	267,686	$20.16
2014	$12,250,548	184,058,400	$0.07	$5,648,209	273,089	$20.68
2013	$10,833,349	181,569,600	$0.06	$5,387,853	274,139	$19.65
Average	***$12,633,918***	***185,983,686***	***$0.07***	***$5,275,066***	***265,251***	***$19.89***

2. Supply and Demand Elasticity

The issue of supply and demand elasticity is addressed in more detail within the context of the following sections. The cost of control technologies cannot be absorbed by Aurora under the current pricing to consumers for district heating and power. Aurora has no alternative but to pass those costs to its customers. Those customers, in turn, would have no choice but to go elsewhere for their heat and power, as Aurora would no longer be competitive with other options. This would be the beginning of a death spiral for Aurora as a business, and the beginning of an increase in lower level emissions in the Fairbanks core as more and more buildings switch to oil or gas for heat.

3. Product prices (cost absorption vs cost pass-through)

Aurora's current product prices are competitive with other power suppliers and heating sources. Aurora's heat business is generally regulated by the Regulatory Commission of Alaska (RCA). District heating prices are set based on Aurora's cost to produce the heat. At the same time, many district heat customers are able to switch to alternative sources of heat, such as oil, gas or wood; therefore, Aurora has a powerful incentive to maintain district heating prices competitive with other heating options. Likewise, GVEA maintains several contracts with various power producers including Aurora. GVEA's portfolio includes power generated with natural gas, hydroelectric gradient, wind, solar, coal, and oil. Aurora's contract with GVEA ensures Aurora's power pricing is competitive and marketable.

District Heating

District heating prices cannot absorb the pass through costs of control technology. Aurora's district heating customer base is approximately 200 including mostly commercial and some residential customers. District steam heating rates are set with oversight by the RCA and do not vary. Hot water district heating prices differ depending on consumers' annual heating needs. The hot water district heating rates are adjusted throughout the year to be competitive with other sources of heat.

Absorbing full or partial costs for upgrades or control technologies is not feasible through district heating rate adjustments. The price adjustment necessary to compensate for the current average annual net loss from district heating (Table 6) would be an increase of $3.71/MMBtu representing a 20% increase in heating costs. A 20% increase in district heat prices per unit energy (MMBtu) is not marketable. The potential is a loss of revenue from customers switching to alternative forms of heat which would make

[2] Based on RCA annual filing from 2013-2017.

district heating even less sustainable and exacerbate air quality due to an increase in ground level emissions.

Electric Generation

Aurora's power pricing cannot absorb the pass through cost of control technologies without revising the current contract and becoming less marketable. Aurora sells its power at wholesale price to GVEA, its sole electric customer. Aurora has averaged 186,000 MWh in net sales annually. Pass through of any additional incurred cost would have to be negotiated with GVEA, and would cause an increase in power costs to all customers in GVEA's service area.

Product Pricing for GVEA including Control Technology Costs

ADEC indicates that SO_2 controls are being considered for BACT or Most Stringent Measures (MSM) at this time.[3] ADEC's estimate of the capital investment of the preferred control technology for Aurora is estimated to be $12,332,076 and the annualized cost is estimated to be $4,284,104. The requirement is that BACT must be installed within 4 years of reclassification of an area from a moderate to a serious nonattainment area.[4] The Fairbanks North Star Borough nonattainment area designation change from "Moderate" to "Serious" was effective June 9, 2017.[5] Since the area is now identified as serious, BACT control would have to be in place by June of 2021. Funds for the capital investment would need to be arranged by 2019 to allow for construction and installation of the control equipment. The power purchase agreement with GVEA would need to be renegotiated prior to committing to construction.

Assuming electrical sales would correspond to the 5-year average (185,984 MWh), the weighted average price per MWh at the Chena Power Plant (CPP) would be $85.51.[6] When the annualized cost of operating the preferred control technology is included, the price of power from the CPP increases to $108.55/MWh; a 27% increase in price of power. The average total electric power consumption of sulfur control on Healy Unit #2 is 550.5 kW.[7] Assuming a comparable station service use, SO_2 control on the Chena Power Plant could require an additional 2.6% for station service load.

The SO_2 control technologies being considered (DSI) require the addition of lime, limestone, or sodium bicarbonate to the gas path prior to the baghouse. The amount of unreacted sorbent added to the process could alter the leaching characteristics of metals from coal ash. Recent testing of coal ash from coal blended with 2% by weight limestone, demonstrated elevated metals leaching from coal ash at various pH. Metals leaching in excess of water quality standards could require Aurora to incur additional disposal costs for coal ash. Aurora would either have to build a coal ash landfill, or take the coal ash to the municipal landfill at a cost to Aurora of $90/ton.[8] If additional costs were incurred by Aurora for disposing 20,000 tons of coal ash, then the price per MWh would need to increase to $118.60; which represents a 39% increase in the price of power.

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[3] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[4] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016.
[5] Federal Register, Vol. 82, No.89, Wednesday May 10, 2017.
[6] 2013 Contract Pricing for 2020: $79.37/MWh (≤150,000 MWh) + $112.12/MWh (>150,000 MWh).
[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.
[8] FNSB. 2014. Interior AK Coal Ash. Pg. 42

Table 5: $/kWh Wholesale Pricing for GVEA including Control Technology Costs

	Average kWh/year (2013-2017)	No Controls	SO2 - DSI	SO2 - SDA	SO2 - WS
Annual BACT Operating Cost		$ -	$4,284,104	$11,862,577	$12,160,961
2020 ($/kWh)	185,983,686	$ 0.09	$ 0.11	$ 0.15	$ 0.15
2020 ($/kWh) -2.5% station load (BACT)	181,334,094	$ 0.08	$ 0.11	$ 0.15	$ 0.15
Coal Ash Disposal - Borough Landfill[1]		$ -	$ 0.12	$ 0.16	$ 0.16

1 - Borough Landfill disposal cost based on 20,000 tons of ash; $90/ton (FNSB. 2014). Interior AK Coal Ash. Pg 42.

Aurora's price of power is in competition with other power producers. If the price of power exceeds that of the competition, Aurora would not be as competitive in the energy market. Currently, GVEA will take as much power as Aurora can produce; however, it is likely that GVEA would reduce the amount of power accepted from Aurora if product prices increase above those of the competition.

4. Expected costs incurred by competitors

The FNSB nonattainment area impacts stationary sources within the area. Aurora's main competitors are power producers outside of the nonattainment area. Aurora's competition will not be required to consider BACT or MSM as a new requirement of a nonattainment area. This puts Aurora at a serious economic disadvantage. It is the only private for-profit power producer in the state being subjected to the $PM_{2.5}$ nonattainment area BACT requirements. Table 5 illustrates the price of wholesale power in $/kWh from Aurora. The price of power with controls is $0.11/kWh. When additional disposal requirements are considered as a result of the use of the control technology, the price of Aurora's wholesale power to GVEA is $0.12/kWh.

Aurora's competition for power sales is primarily natural gas generated power; including Anchorage Municipal Light and Power (AMLP), Matanuska Electric Association, Inc. (MEA), and Chugach Electric Association (CEA). Aurora is also in competition with GVEA's fleet including the coal facilities (Healy #1 and Healy #2). The expected increase in price of Aurora's power due to BACT will make its power less marketable. At $0.12/kWh, the price of Aurora's power to GVEA would exceed AMLP ($0.09/kWh), Healy #1 ($0.10/kWh), MEA ($0.10/kWh), and CEA ($0.11/kWh) based on GVEA's cost of power report in 2017[9]. Aurora currently provides 14% of GVEA's power requirements. At current prices, Aurora's power is competitive. An increase in the price of power to $0.11/kWh or $0.12/kWh would likely change that perspective.

5. Company Profits

Net income (loss) for Aurora over the past five years are not sufficient to absorb annual control technology costs for any of the control technologies proposed. Table 6 below includes the net income (loss) from district heating, electrical generation and the combined company income (loss) for years 2013

[9] 2017 GVEA Annual Report to the RCA.

through 2017. Net income (loss) include income generated from district heat and power sales minus the operating costs as presented in Table 2 and include nonutility income, interest income, miscellaneous amortizations, and interest expenses.

Table 6: Aurora Energy, LLC – 5 Year Net Income (Losses)

Year	Electric	District Heating	Net Income (loss)
2017	$ 801,037.00	$ (377,585.00)	$ 423,452.00
2016	$ 419,092.50	$ (1,808,914.00)	$ (1,389,821.50)
2015	$ 1,094,599.25	$ (1,059,348.00)	$ 35,251.25
2014	$ 321,876.05	$ (892,950.00)	$ (571,073.95)
2013	$ 420,072.77	$ (775,432.00)	$ (355,359.23)
Average	***$ 611,335.51***	***$ (982,845.80)***	***$ (371,510.29)***

The annual cost to operate the preferred technology is $4,284,104 (Table 1 & 4); the average 5-year net income (loss) for Aurora is ($371,510) [Table 6]. Conclusively, Aurora is not able to absorb the cost of additional control technologies.

The only alternative for Aurora to address annual operating expenses for any proposed control technologies would be to attempt to renegotiate the power contract to raise the price of power to GVEA. However, the rate adjustment would increase the price of Aurora's power to the extent that it would be less competitive.

6. Employment Cost

The state's calculations for annual operation costs of the proposed technologies include labor cost increases. The increases vary depending on the type of control technology. As a part of the state's analysis for SO_2 controls, annualized cost increases include the projection of additional labor for operation, maintenance, and administration.

7. Other Costs

No additional costs were considered.

ADEC has not shown that Aurora's, nor other stationary source's, SO_2 emissions are a significant contributor to the nonattainment area problem. ADEC does not know whether installation of BACT or MSM on stationary sources will significantly mitigate the impact of SO_2 on particulate concentration. Aurora cannot afford the control measure or technology that has been selected by the ADEC in the preliminary BACT analyses. The basis for this determination is that Aurora has consistently shown insufficient income to absorb the cost of the control technologies. Alternatively, increasing the price of power or heat to accommodate the cost of control technology will price Aurora's products out of the market. Any increase in district heating prices would make alternative sources of heat more attractive to consumers. The result would be a loss in business from customers switching to alternate sources of heat. This change in heating source could exacerbate pollution emissions at the ground level due to customers' use of distributed home heating alternatives. Aurora's district heating displaces the emissions from the equivalent of 2 – 2.5 million gallons of heating oil. The current power purchase agreement with GVEA allows Aurora's power to be competitive with other power sellers. The cost of additional control technology would have to be negotiated with Aurora's one customer based on its power purchase agreement and make Aurora's power prices less competitive; and subsequently, less sustainable.

3.0 Proposed Alternative BACT – District Heating

Aurora is sympathetic to the requirements of the Serious Nonattainment Area and believe that a reasonable alternative exists within the framework of what is economically feasible. As previously discussed, Aurora asserts that imposing retrofit controls, as proposed by ADEC, on its older boilers in the next four years is economically infeasible and could have negative impacts on the goals of the community to achieve attainment with the $PM_{2.5}$ standard. As such, Aurora has developed a list of mitigating measures that are more economically sustainable and will have a direct impact on the community with respect to achieving attainment with the $PM_{2.5}$ standard. Included as alternatives are the expansion of district heating, a wood drying kiln, and the potential use of biomass.

3.1 District Heating

Aurora is proposing that past district heat expansions as well as future district heating projects be considered as BACT for the Chena Power Plant. As it stands, Aurora's district heating displaces about 42 tons of SO_2 and 2 tons of particulates annually. District heating is referenced in both the Moderate Area State Implementation Plan (SIP)[10] and the Preliminary Serious Area SIP[11] as a Pollution Control Measure for the FNSB NAA. As stated in the Moderate Area SIP, "An increase in the coverage of the district heating systems would therefore result in a decrease in measured $PM_{2.5}$ concentrations". Based on modeling results, the $PM_{2.5}$ concentration attributed to Aurora during an episode in 2008 was 0.02 μg/m^3 and the SO_2 concentration at ground level from Aurora represents 0.75 μg/m^3 (See Table 7).[12] The implication of the small pollutant contribution from Aurora at ground level is that taller stacks decrease the impact from emissions at ground level. The amount of pollutant loading at ground level within the nonattainment area is mitigated by district heating through the removal of ground level source emissions and vertically displacing them. An added benefit to increasing district heat coverage is an increase in efficiency at the plant. The plant is generally base loaded and driven to operate at a maximum capacity; there is moderate room for growth, but realistically, the plant is nearing its maximum capacity. The plant could accommodate, roughly, an additional 100 MMBtu/hour of heating capacity while still being able to provide a modest amount of electricity.

Table 7: Summary of Six Major Fairbanks Point Source Plumes from CALPUFF for the Episode (Jan.23rd to Feb. 9th, 2008) Average Surface Concentrations at the State Office Building of PM2.5 and SO2 in ug/m3.

Power Plant	Episode average SO_2 (μg/m^3)	Episode average $PM_{2.5}$ (μg/m^3)
UAF- 316	2.75	0.16
Aurora- 315	0.75	0.02
Zehnder-109	0.48	0.19
Flint Hills-071	0.016	0.38
GVEA NP-110	3.8	1.45
Ft. WW- 1121	14	1.6
Total surface concentration	21.8	3.8

In order to quantify the impact district heating has on the nonattainment area, Aurora evaluates the potential use of fuel oil based on

[10] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 42.
[11] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[12] ADEC. 2014. Moderate Area State Implementation Plan. Section III.D.5.8-11.

a conversion from the heating load compensated by the plant for district heating. A fuel oil heating value of 137,000 btu/gal and an assumed efficiency of 85% for heating appliances are used to determine the quantity of heating oil equivalent to the district heating load. Since SO_2 and $PM_{2.5}$ are the pollutants of most concern, Aurora is using emission rates for fuel oil using EPA's emission inventory warehouse, AP-42. Using the value of 2566 ppm sulfur in heating oil[13], an emission rate of 36.92 lbs/10^3 gallons (2.64×10^{-1} lbs/MMBtu) for SO_2 emissions and 0.4 lbs/10^3 gallons (2.86×10^{-3} lbs/MMBtu) for filterable or direct $PM_{2.5}$ and 1.3 lbs/10^3 gallons (9.29×10^{-3} lbs/MMBtu) for condensable $PM_{2.5}$ are derived. Using these emission rates, Aurora can evaluate the impact of district heating on the removal of SO_2 and $PM_{2.5}$ from the nonattainment area.

As part of a further analysis, the SO_2 is converted to $PM_{2.5}$ by using an ADEC derived method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration from various sources. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Through the use of a dispersion model, CALPUFF, ADEC determined that 22% of modeled SO_2 concentration are from point sources at ground level, 78% are from central oil, and <1% from mobile sources. Using this information and the ADEC's methodology (based on 'scenario 2'), a ratio of 5.5 tons SO2 emissions from major sources is estimated to form 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate [8.38 TPD/(1.1 µg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$.[14] Based on the same methodology, the ratio of SO_2 from fuel oil (78% of modeled concentration) to particulates is 0.8 tons of fuel oil SO_2 emissions to 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate [4.12 TPD[15]/(3.9 µg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. To summarize this information and that in Table 8, wood smoke produces 18 times more $PM_{2.5}$ than the SO_2 from point sources and 2.6 times more $PM_{2.5}$ than fuel oil.

Table 8: Source pollutant emission and equivalent contribution in µg/m^3 of $PM_{2.5}$.

Pollutant	Point Sources (SO_2)	Fuel Oil (SO_2)	Wood Smoke
Emissions (tons)	5.5	0.8	0.3
$PM_{2.5}$ Equivalent Concentration (µg/m^3)	1	1	1

3.2 District Heat Expansion

District heating from Aurora mitigates emissions from ground level sources. The 5-year average (2013-2017) heating value of Aurora's district heat supply is 265,251 mmbtu/year. That is equivalent to about 2.3 million gallons of heating oil per year; assuming a heating value of 137,000 btu/gal and an 85% efficiency for an oil fired furnace. Using these values, district heat displaces about 42 tons of SO_2 from ground level emissions per year and 2 tons of $PM_{2.5}$ in the down town area. Since 2008, Aurora has added district heating equivalent to 243,000 gallons of fuel oil per year. The impact of the addition is equivalent to the removal of 3510 lbs of wood smoke per year based on SO_2 reduction from fuel oil [4.5 TPY SO_2 fuel oil/0.77 tons SO2 fuel oil/1 µg/m^3 x 0.3 tons wood smoke/1 µg/m^3 x 2000 lbs/ton]. District heating records show that 67% of heating use is between November – March (151 days). The loading that

[13] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 102.
[14] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.
[15] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 27.

was mitigated since 2008 is approximately 16 lbs/day of wood smoke equivalence during the winter months.

Aurora has the mechanical potential to expand district heating another 100 mmbtu/hr of additional heating. The equivalent SO_2 removal potential would be about 24 tons per year based on the displacement of 1.3 million gallons of heating oil No.2 (fuel oil S% = 0.26).

3.3 District Heating Economics

Installation of district heating can be costly. The evaluation of DH as a control technology for the plant is difficult to assess a cost/ton comparison. Ideally, the expansion cost would be mitigated by revenue generated from the use of district heating. The business model for district heating would justify the expansion; the added benefit would be the reduction in pollutants emissions from ground level sources, and a decrease in the output based emission rate. In general, efficiency gains at the plant is a sustainable practice with the benefit of reducing pollutant emissions at ground level.

3.4 Output Based Emission

District heat expansion has the added benefit of making the plant more efficient. A method of illustrating efficiency gains with respect to pollutant emissions is in the derivation of an output based emission rate. The output based emission rate for SO_2 at the plant is approximately 4.6 lbs/MW of energy output. The emission rate is based on a conservative calculation using the 5-year weighted average coal sulfur content and converting all of it to SO_2. The denominator consists of net power and net district heat sales in MW. When the maximum output of district heating is added to the denominator, the emission rate is reduced to 3.4 lbs/MW. This represents a 27% reduction in the emission rate per energy output.

The output based emission rate can be used to show efficiency gains with respect to pollutant emissions. Efficiency gains through the use of central heat and power facilities clearly demonstrate the advantages of minimize emission increases while maximizing energy output.

4.0 Proposed Alternative BACT - Firewood Drying Kiln

Couched within the benefits of district heating, Aurora is proposing an alternative to address its potential formation of fine particulate matter ($PM_{2.5}$) from sulfur dioxide. According to a 2008 report by the Northeast States for Coordinated Air Use Management (NESCAUM), for every 10 percentage point increase in the moisture content of wood, the $PM_{2.5}$ emissions increase by 65% to 167%. The increase in emissions is due to increased amount of wood needed to evaporate the extra moisture and poor combustion conditions leading to reduced heat transfer efficiency. Wood fuel use may double if wet wood were burned as opposed to dry wood.[16] Aurora is proposing to develop and operate a firewood drying kiln using district heat from the Aurora plant to help mitigate the use of wet wood. The general idea is that, along with district heat conversions, Aurora would offset its potential $PM_{2.5}$ formation by providing dry wood to the community from a kiln. The kiln would require 3.5 mmbtu/hour of thermal loading from district heating. The initial moisture content in the wood is assumed to be around 50%; the kiln would evaporate 35% of the moisture to a wood moisture content of 15% or less. By conditioning solid fuel (fire wood) to be used in homes, district heating is effectively expanded without the cost of installation.

[16] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 22.

4.1 Equivalent Emissions

The state has derived a method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Based on 22% of modeled SO_2 concentration from point sources at ground level, a ratio of 5.5 tons SO_2 emissions is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$ as ammonium sulfate. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 $\mu g/m^3$ of $PM_{2.5}$.[17] Using the fore mentioned conversions, Aurora estimated the power plants SO_2 emissions equivalent to wood smoke emissions. Based on an emission rate at Aurora of 608.3 tons/year of SO_2 (1.67 tpd), the wood smoke emission equivalent is 181 lbs/day [1.67 TPD/ (5.5 tons SO_2 from major sources/1 $\mu g/m^3$) x 0.3 tons of wood smoke/1 $\mu g/m^3$ x 2000 lbs/ton]. The equivalent annual wood smoke emission to 608.3 tons of SO_2 emission is proposed to be mitigated through drying wood by reducing 35% moisture from cord wood.

Table 9: SO2 Conversion to Wood Smoke Equivalent Emission

Source of Emissions	SO_2 Emissions (tpd)	$SO_2/PM_{2.5}$ (tpd)/($\mu g/m^3$)	Wood Smoke/$PM_{2.5}$ (tpd)/($\mu g/m^3$)	Wood Smoke Equivalent (lbs/day)
Aurora Energy	1.67	5.5	0.3	181
Displaced Heating Oil Use - DH	0.01	0.8	0.3	10

The emission reduction for $PM_{2.5}$ in lbs/MMBtu was derived using the ADEC's referenced information within the Appendices of the Moderate Area State Implementation Plan (See Tables 10 & 11). The average emission rate for wood burning devices at 50% moisture (1.14 lbs/MMBtu) was subtracted from the average emission rate for wood burning devices at 15% moisture (0.67 lbs/MMBtu). The equivalent amount of cords needed to account for 100% of Aurora's annual SO_2 emissions is 8,495 cords per year.

Table 10: Emission Factors based on wood moisture content

Wood Burning Devices	EF PM2.5 lbs/ton[1]	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu
Moisture content (%)		0		15		50	
non-EPA certified Wood Stoves	11.6	8,119	7.14E-01	6,901	8.40E-01	4,060	1.43E+00
EPA Wood stove non-catalytic	7.57	8,119	4.66E-01	6,901	5.48E-01	4,060	9.32E-01
EPA Wood stove catalytic	8.4	8,119	5.17E-01	6,901	6.09E-01	4,060	1.03E+00
Hydronic Heater weighted 80/20 (OWB unqualified/OWB-Ph2)	9.43	8,119	5.81E-01	6,901	6.83E-01	4,060	1.16E+00
Average emission factor	9.25	8,119	5.70E-01	6,901	6.70E-01	4,060	1.14E+00
Note: 1 - Appendix III.D.5.6-105, Table 5.6-40; 2 - Appendix III.D.5.6-86, Table 5.6-31							

[17] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

Table 11: Calculation to determine how much kiln dried wood is necessary to mitigate AE's SO_2 emissions.

PM 2.5 Daily Emissions Reduction [Scenario 2] (lbs/day)	181
PM 2.5 Annual Emissions Reduction (lbs/year)	66,003
Spruce weight at 20% moisture	2,550
Dry Wood (%) moisture	15
Wet Wood (%) moisture	50
Emission Diff. wet vs. dry (lbs/MMBtu)	4.69E-01
Daily Wood processing minimum (MMBtu/year)	140,695
Cords per year	8,495
cords/load	42
Loads per year	202

4.2 Firewood Kiln Economics

The capital cost and annualized cost of the kiln is much less than that of the other BACT alternatives. The cost effectiveness is determined by a $/Cost ratio based on drying wood at a maximum potential of 8,495 cords of wood to reduce, effectively, 608.3 tons per year of SO_2-equivalent emission. The annualized cost is used to derive the cost effectiveness ratio of $980 per ton of pollutant removed.

Table 12: Cost Effectiveness of Kiln

Control Technology	PM 2.5 Reduction (tpy)	Equivalent SO2 Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Cost ($/year)	Cost Effectiveness ($/ton SO_2)
Wood Kiln	32.5	608.3	$ 1,500,000	$ 736,078	$ 980

Unlike a traditional BACT approach, the effective emission reduction is hinged on the marketability of dry wood. Aurora plans to market the kiln dried wood as a benefit from a performance and air quality standpoint. The Fairbanks Northstar Borough, ADEC and EPA all have an important role in enforcing the use of dry wood for home heating the NAA.

5.0 Proposed Alternative BACT - Biomass Co-Firing

Aurora's boilers are subject to 40 CFR 63 subpart JJJJJJ. Under the rule, the Chena Power Plant (CPP) boiler units are classified as coal-fired boilers. The definition of coal-fired boiler subcategory extends to coal boilers that burn up to 15% biomass on a total fuel annual heat input basis. This flexibility in definition would allow Aurora to burn up to 15% biomass and still retain its classification as a coal-fired boiler. Aurora has been involved in a projects with Alaska Center for Energy and Power (ACEP) and the US Forestry Service using biomass (wood chips and refuse) as a substitute for coal. The projects did not demonstrate much of a change to the current operations; however, the material used had a significant amount of moisture (40%) and was not uniform. Sizing of the material was an issue and created problems. Biomass refuse and chips were not appropriately sized and created issues with material feeding through the auxiliary coal feed system. Also, due to density differences, material segregation within the bunkers occurred; wood chips tended to be pushed to the top of the coal. Ultimately, the lessons learned from the project were that with the right material sizing and processing, biomass could be used in the boilers to

help increase efficiency. As noted by operators during the project, the biomass burned off quickly leaving holes within the coal bed which allowed for air pockets which qualitatively made coal combustion more effective. The theory is that air voids left after the biomass was burned off facilitated greater air-to-fuel contact. Also, the rapid burning of the biomass may have increased the heat of the coal bed which helped coal combustion. Although this theory has not been vetted though rigorous research, the potential benefits of using biomass within the process may be substantial. At the very least, biomass has very little sulfur and could be a measure to mitigate the emissions of SO_2 from the plant.

The material used during the biomass project at Aurora was unprocessed and, consequently, not uniform. If the biomass material was processed and met some consistency standards there could be a significant measurable gain in efficiency. As such, processed biomass in the form of industrial grade pellets can provide a consistent sizing which would be compatible with the sizing of the stoker coal used at the Chena Power Plant (CPP). The benefit of using an industrial grade pellet is that the anticipated heat content of the pellets are assumed to be upwards of 8300 btu/lb, the moisture content is near 0%, and there is very little sulfur in the fuel. The cons of using an industrial grade biomass pellet is the cost of the fuel which could be as high as $295/ton. At this cost, the use of biomass is not economical. Furthermore, Aurora has not determined whether or not enough raw timber supply is available around the Fairbanks area to accommodate a consistent 15% blend rate. However, if waste biomass material, such as sawdust or bark, from local wood sellers were processed into pellets the raw material could be acquired at a low cost.

5.1 Biomass Economics

Biomass pellets, due to their lack of sulfur, could be used as mitigation for SO_2 emissions. As stated above, the negative aspect of pellets is in the cost and potential lack of access to raw material supply. In order to derive a price point for pellets that would be acceptable as a control technology, a cost effectiveness value of $3,125/ton SO_2 removed is used as a reference. This is a conservative estimate derived by the state in the moderate area SIP.[18] If the 5-year average revenue generated by the plant is divided by the 5-year average coal use we get a value of $79.09 revenue/ton of coal. Pellets have a higher btu/lb content than the coal and pellets have no moisture. To account for this discrepancy, coal heating value is considered after the evaporation of moisture. The energy needed to vaporize free moisture (h_{vap} =1049 btu/lb @ 77F) is multiplied by the moisture fraction of coal to derive the heat content of the coal at 0% moisture. When comparing the wood pellets to coal, the 5-year average heat content (7623 btu/lb) and moisture (29%) is considered. The heating value of coal without moisture is 7304 btu/lb (7623 btu/lb –

Table 13: Biomass and Coal Fuel Revenue/MMBtu

hhv pellets btu/lb	8,300
hhv pellets mmbtu/ton	16.6
hhv coal btu/lb	7,613.05
coal moisture	29%
heat of vaporization of water @ 77F btu/lb	1,049.70
coal btu/lb -vaporized free water	7,304
coal mmbtu/ton -vaporized free water	14.6
pellet coal equivalent	1.14
revenue/ton of coal	$ 79.09
revenue/mmbtu of coal	$ 5.41
revenue/mmbtu of pellets	$ 4.76

[18] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

1049.7*29/100). Pellets would have a heating content of 8300 btu/lb and no moisture. If the price of the pellets were $84/ton, the cost effectiveness value would be $3,093.04/ton SO_2 removed.

The emission reduction potential using pellets at 15% total fuel loading is 91.24 tons of $S0_2$ per year. Aurora is actively pursuing this concept; however, running the boiler with 15% biomass has not been tested and a supply of industrial wood pellets at the preferred price has not been identified nor has the availability of the raw material supply been verified.

Table 14: Biomass Cost Effectiveness Calculation

capital investment (hopper modification to auxillary coal feed system)	$300,000.00
loan period (years)	$5.00
interest rate (%)	8%
monthly loan amount	$6,082.92
Annual loan amount	$72,995.04
Burden for 0.5 man equivalent (2016)	$65,520
5-year avg Annual Coal (tons)	221,758.29
5-year avg coal sulfur (%)	0.14%
potential max SO2 (tons/yr)	608.24
Annual pellets (%)	15%
Annual pellets (tons)	29,272.22
emission reduction (tons/yr)	91.24
Cost pellets ($/ton)	$84.00
Annual cost	$2,597,381.16
Annual revenue	$2,315,186.17
annual burden of pellets	$282,194.99
cost/ton removed	3,093.04

6.0 Proposed Alternative BACT – Reduction in Potential to Emit

Aurora proposes to monitor the stack gas emissions out of the common stack. The purpose of the monitoring would be to ensure compliance with an SO_2 emission rate of 190 ppm. Instead of taking a reduction in the sulfur content of the coal or PTE for SO_2 emissions, monitoring the stack gas emissions and maintaining a rolling 30-day average at or under 190 ppm ensures that the plant is not exceeding a certain loading rate equal to 0.25% coal sulfur content. Using the SO_2 emission calculation in the Air Quality Operating permit AQ0315TVP03 Rev. 1, Condition 22.1.c; a stack gas concentration of 7.5% O_2; and adjusting the S% to 0.25 (in this ultimate analysis the S% is 0.26), the SO_2 concentration is 188 ppm as illustrated below:

Figure 1: SO_2 emission calculation

SO2 Concentration PPM = (1.00X 10^6 xmol_{SO2})/(mol_{SO2} +mol_{CO2}+mol_{O2}+mol_{N2})					
SO2 PPM =					
Where:					
mol SO2 =	[wt% Sfuel,%]/32.06				
mol CO2 =	[wt%Cfuel,%]/12.01				
mol O2 =	MF x [(wt%Nfuel,%]/28.01)+(4.76xmolCO2)+(4.76xmolSO2)+(1.88xmolH2O)-(3.76x[wt%Ofuel,%]/32.00)]				
MF =	[vol%O2,exhaust,%]/(100%-4.76x[vol%O2, exhaust, %])				
mol H2O =	[wt%Hfuel,%]/2.016				
mol N2 =	([wt%Nfuel,%]/28.01)+(3.76xmolSO2)+(3.76xmolCO2)+(1.88xmolH2O)+(3.76xmolO2)-([wt% Ofuel,%]/8.51)				
Constituent	mols in flue gas	Ultimate/proximate analysis (AE08162018)	%weight (dry)	Atomic Mass	Atomic Mass
mol_{SO2}	0.007796663	wt% $Sulfur_{fuel}$, %	0.25	Sulphur	32.065
mol_{CO2}	5.219382233	wt% $Carbon_{fuel}$, %	62.69	Carbon	12.011
mol_{H2O}	2.277011608	wt% $Hydrogen_{fuel}$, %	4.59	Hydrogen	1.0079
mol_{O2}	3.098516312	wt% $Nitrogen_{fuel}$, %	0.93	Nitrogen	14.007
mol_{N2}	33.05690137	wt% $Oxygen_{fuel}$, %	21.8	Oxygen	15.999
MF	0.116640747		%vol		
		Oxygen exhaust %	7.5		
SO_2 Concentration	188.404394	Source Test Required if exhaust SO_2 Concentration is greater than 500 ppm			

As mentioned, 190 ppm of SO2 emissions on a 30-day rolling average represents an overall PTE reduction from 0.4% sulfur content to 0.25% while still allowing flexibility with respect to coal quality exceeding 0.25% sulfur.

7.0 Precursor Demonstration

As part of the Serious SIP development, states are required to develop Best Available Control Measures for all source sectors that emit $PM_{2.5}$ and the four major precursor gases (e.g., NOx, SO_2, NH_4, and VOC). The analysis specific to the major stationary source is a Best Available Control Technology analysis. Within the rule, if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls for a precursor gas are not required to be implemented.[19] The regulations provide for three kinds of precursor analyses, comprehensive (which consider precursor emissions from all sources in the nonattainment area), Major stationary source (which consider precursor emissions from major sources), and Nonattainment New Source Review (which considers potential precursor emissions from new sources).[20] For each of the first two analyses, there are two varieties available to the state: a concentration-based analysis (compares the precursor contributions to a numerical threshold) and a sensitivity-based analysis which consider other factors to evaluate if reductions in the precursor emissions would significantly reduce $PM_{2.5}$ levels in a nonattainment area.

The ADEC has successfully demonstrated that oxides of nitrogen NOx and VOC are not a significant precursors to the area. The NOx precursor demonstrations included a comprehensive demonstration with a sensitivity based analysis for the community and a Major Stationary Source – concentration based analysis which demonstrated that major sources are not a significant contributor to the nitrate-based particulate formation.[21] The state also conducted a comprehensive, concentration-based analysis for SO_2 and concluded that SO_2 emissions in the NAA contribute 5.4 $\mu g/m^3$ in the Fairbanks area and 4.9 $\mu g/m^3$ of $PM_{2.5}$ in the North Pole area. Since these concentrations exceed the significance threshold of 1.3 $\mu g/m^3$ (now 1.5 $\mu g/m^3$)[22], the ADEC proposes not to conduct a sensitivity-based precursor demonstration nor are they considering a major source precursor demonstration.

EPA's draft precursor guidance recognizes that the significance of a precursors contribution is determined based on the facts and circumstances of the area which include source characteristics such as source type, stack height, and location.[23] The rationale for doing a precursor demonstration fits with the site-specific factors listed in the EPA guidance, namely tall stacks. However, the ADEC and EPA have been resistant to performing or further considering a Major Source precursor demonstration.

Aurora sought a third party opinion (Ramboll Environmental) regarding the possibility of a successful SO_2 precursor demonstration that could demonstrate that major stationary sources are an insignificant part of the contribution to the nonattainment area. According with the EPA's precursor demonstration guidelines, a successful major stationary source precursor demonstration must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ standard (1.5 $\mu g/m^3$). If the 'contribution-based'

[19] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[20] See 40 C.F.R. § 51.1006
[21] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[22] Draft EPA (2016b) guidance recommended 1.3 $\mu g/m^3$ for the $PM_{2.5}$ 24-hour NAAQS as the appropriate threshold to identify insignificant contributions to $PM_{2.5}$ concentrations. A more recent updated technical basis document, EPA (2018) now recommends a threshold for identifying significance of 1.5 $\mu g/m^3$.
[23] EPA's 2016 Draft $PM_{2.5}$ Precursor Demonstration Guidance.

analysis indicates that the impact 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 have only an insignificant impact on lowering $PM_{2.5}$.

Two main hurdles exist to conducting a credible SO_2 precursor demonstration; 1) the large contribution of sulfate by major and minor source contribution to the nonattainment area; and 2) the large under prediction of sulfate mass through the model (CMAQ). In essence, while the SO_2 sources are observed to contribute significantly to the $PM_{2.5}$ nonattainment area, current modeling systems are not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2.

Utilizing the ADEC's information within the Moderate Area SIP, Aurora's third party consult suggests that there is relevant data to suggest major sources are potentially insignificant contributors to the NAA.

> "…data analyses and modeling conducted for the Fairbanks moderate area SIP provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment."[24]

As such, a Major Source SO_2 precursor demonstration must be pursued by the ADEC. It is an undue burden for Aurora and other major sources within the NAA subject to the requirements of control measures (BACT, and more likely MSM) considering that there is data to suggest that major sources could be insignificant. Even though updating models and research into the chemistry of sulfate particulate formation is costly and time consuming, it is due diligence on the agencies part to further elucidate the impact of major sources. Ultimately, Aurora will continue to pursue alternative control measures as proposed within this document under the assumption that the agencies (ADEC and EPA) will continue to vet the sulfate contribution disparity between model and observed values with the perspective of major stationary source contribution.

8.0 Conclusion

The proposed BACT alternatives in this document and accompanying information demonstrate that the ADEC proposed BACT are economically infeasible and do very little to solve the air quality problem in the nonattainment area. EPA, the State of Alaska, as well as the local community understand and agree that the majority of the $PM_{2.5}$ problem in the area is from home heating sources. Aurora contends that requiring the implementation of the ADEC proposed BACT controls would cause the pollution problem to worsen due to our district heat customer's refusal to accept a higher cost heating product and instead switching to fuel oil, or wood burning.

Aurora does not believe ADEC has demonstrated that the point sources, or more specifically Aurora, are contributing to the $PM_{2.5}$ problem in a significant enough way to warrant the need for additional control measures. Aurora believes that a precursor demonstration would prove this assertion one way or another. Aurora believes a precursor demonstration is possible and requests that ADEC and the EPA move forward with conducting a precursor demonstration in parallel with the implementation of the SIP. Should a precursor demonstration show that the point sources do not cross over the significance threshold, all point sources should be released from further compliance with the $PM_{2.5}$ requirements.

Even though Aurora is not convinced that major source emissions exceed the significance threshold for $PM_{2.5}$ within the NAA, Aurora is interested in being a part of the solution to reduce $PM_{2.5}$. Aurora's

[24] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks".2018.

proposed alternative BACT controls are more effective from an environmental perspective and cost substantially less than the ADEC proposed BACT controls. The table below shows the potential amount of SO_2 and $PM_{2.5}$ removed from the NAA by Aurora's proposed alternative BACT.

Table 15: Summary of BACT Alternatives and Potential Emission Reduction

Emissions	SO2 (tpy)	PM 2.5 (tpy)	Qualifying Parameters
District Heating (Current Operating Conditions)	42 tpy at ground level	2 tons at ground level	250,000 – 300,000 mmbtu per year
District Heating (Potential Expansion)	24 tpy at ground level	1 ton at ground level	100 mmbtu/hr expansion potential
Wood Kiln	608.3tpy	33 tons at ground level	8495 cords/yr
Biomass Co-Firing	91.2 tpy	--	15% by fuel heat input from industrial pellets
Potential to emit reduction	38% reduction in PTE (854 tpy)	--	State upper limit of 500 ppm over 3 hours. Proposed 190 ppm as a new PTE
Total Potential Reduction	1,619.5 tpy	36 tpy	

As clearly shown in this table, the environmental benefits from Aurora's proposed alternative BACTs will positively impact the current NAA. Aurora is prepared to move forward with implementing these alternative BACTs as soon as ADEC is able to provide Aurora with the assurance that additional control measures or fees will not be required in order to demonstrate compliance with the PM2.5 regulations for the NAA.

Aurora is committed to continuing to work with ADEC, EPA and the local community in working toward meaningful solutions to the air quality problem in Interior Alaska.

Appendix A (Economic Analysis Spreadsheets – V1)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 450 Feet above sea level

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80 percent
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	10 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2 acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	30 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50 percent*
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016
CEPCI for 2016	536.4 Enter the CEPCI value for 2016 — 584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea
Electricity ($Cost_{elect}$)	0.210 $/kWh
Catalyst cost ($CC_{replace}$)	160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*
Operator Labor Rate	63.00 $/hour (including benefits)

CEPCI = Chemical Engineering Plant Cost Index

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day 4.00 hours/day* * 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005
Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year
NOx removal factor (NRF) =	EF/80	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour
Residence Time	$1/V_{space}$	0.03	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF x\ CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$1,728,014 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$2,921,054 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,723,709 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,728,014 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,921,054 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$4,587 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

<u>Step 1</u>: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

<u>Step 2</u>: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

<u>Step 3</u>: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

<u>Step 4</u>: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

<u>Step 5</u>: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 497 MMBtu/hr

What is the higher heating value (HHV) of the fuel? 7,560 Btu/lb

What is the estimated actual annual fuel consumption? 569,114,000 lbs/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 365 days

Plant Elevation 450 Feet above sea level

Inlet NO_x Emissions (NOx_{in}) to SNCR 0.37 lb/MMBtu

NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known) 40 percent

Estimated Normalized Stoichiometric Ratio (NSR) 1.05

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Concentration of reagent as stored (C_{stored}) 50 percent*

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Denisty of reagent as stored (ρ_{stored}) 71 lb/ft^3

Concentration of reagent injected (C_{inj}) 50 percent

Number of days reagent is stored ($t_{storage}$) 30 days

Estimated equipment life 20 Years

Select the reagent used Urea

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25 Percent		
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*		
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0088 $/gallon*		
Electricity ($Cost_{elect}$)	0.210 $/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times tstorage \times 24)$/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent} \times ((1/C_{inj})-1)$ =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565 in 2016 dollars
Indirect Annual Costs (IDAC) =	$511,631 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$989,197 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82 in 2016 dollars
Direct Annual Cost =		$477,565 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$508,837 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$511,631 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$989,197 per year in 2016 dollars
NOx Removed =	318 tons/year
Cost Effectiveness =	$3,107 per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO_2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.222	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na_2SO_4 and unreacted dry sorbent as Na_2CO_3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.24**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015-07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($) Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection, but not including field installatior
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	6.64	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.07	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectio
VOMP ($/MWh) = Q*T*10	=	$	0.507	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**9.21**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i (1+i)^n] / [(1+i)^n - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 30				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0669	=	$	1,383,976	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**2,430,578**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,015,463**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,601,940**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		546	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**8,423**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.122	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.280	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.462**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.876	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars) **Comments**

Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5

BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,028,350	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,426,798	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	34,042,802	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,238	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,404,280	Engineering and construction management costs
A2 = 10% of BM	=	$	3,404,280	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,404,280	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,255,642**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,609**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,212,782	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,468,425**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,690**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,646,842	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**51,115,267**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,859**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO (\$/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	\$	38.12	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = BM*0.015/(B*A*1000)	=	\$	12.38	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	\$	1.29	Fixed O&M additional administrative labor costs
FOM (\$/kW yr) = FOMO + FOMM + FOMA	**=**	**\$**	**51.79**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR (\$/MWh) = K*P/A	=	\$	1.06	Variable O&M costs for lime reagent
VOMW (\$/MWh) = L*Q/A	=	\$	0.31	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	=	\$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	=	\$	0.75	Variable O&M costs for makeup water
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**\$**	**7.29**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	\$	854,570	CC Manual
Administrative charges (2% of total capital investment)	=	\$	1,022,305	CC Manual
Property tax (1% of total capital investment)	=	\$	511,153	CC Manual
Insurance (1% of total capital investment)	=	\$	511,153	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	\$	3,420,477	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**\$**	**6,319,657**	
TOTAL ANNUALIZED OPERATING COSTS (2012 \$)	**=**	**\$**	**9,499,458**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 \$)	**=**	**\$**	**8,716,232**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		702	
SO_2 COST-EFFECTIVENESS, \$/ton removed	=	**\$**	**12,408**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.16	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.283	1.811*K
Aux Power	**M**	**(%)**	**2.098**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.913	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,531,374	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,684,600	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,323,921	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,508,019	Total base cost including retrofit factor
BM ($/kW)	=	$	1,364	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,750,802	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,750,802	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,750,802	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	**=**	**$**	**48,760,424**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	**=**	**$**	**1,773**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,438,021	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	**=**	**$**	**51,198,446**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	**=**	**$**	**1,862**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,119,844.55	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**56,318,290**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	**=**	**$**	**2,048**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.25**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.36	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.41	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**7.10**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	713,645	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,126,366	CC Manual
Property tax (1% of total capital investment)	=	$	563,183	CC Manual
Insurance (1% of total capital investment)	=	$	563,183	CC Manual
Capital Recovery Factor (CRF) = [i (1+i)^n] / [(1+i)^n - 1]				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,768,647	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,735,024**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,634,230**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,839,892**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		773	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**11,440**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix B (Economic Analysis Spreadsheets – V2)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron: No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)? 497 MMBtu/hr

What is the higher heating value (HHV) of the fuel? 7,560 Btu/lb

Simpson, Aaron: Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron: Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

What is the estimated actual annual fuel consumption? 569,114,000 lbs/year

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the net plant heat input rate (NPHR) 18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 450 Feet above sea level

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (selected) Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 365 days

Number of days the boiler operates (t_{plant}) 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR 0.37 lb/MMBtu

NOx Removal Efficiency (EF) provided by vendor 80 percent

Stoichiometric Ratio Factor (SRF) 0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron: Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron: EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Number of empty catalyst layers (R_{empty}) 1

Ammonia Slip (Slip) provided by vendor 10 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known) UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known) 179,783.2 acfm

Simpson, Aaron: April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$) 24,000 hours

Estimated SCR equipment life 15 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T) 310 °F

Simpson, Aaron: April 7, 2016 Source Test

Base case fuel gas volumetric flow rate factor (Q_{fuel}) 516 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored}) 50 percent*

Density of reagent as stored (ρ_{stored}) 71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$) 30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used Urea

Enter the cost data for the proposed SCR:

Desired dollar-year 2016

CEPCI for 2016 536.4 Enter the CEPCI value for 2016 584.6 2012 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i) 5.25 Percent

Reagent ($Cost_{reag}$) 1.62 $/gallon for a 50 percent solution of urea

Electricity ($Cost_{elect}$) 0.210 $/kWh

Simpson, Aaron: GVEA rates. http://www.gvea.com/rates/rates

Catalyst cost ($CC_{replace}$) 160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Labor Rate 63.00 $/hour (including benefits)

Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year	
NOx removal factor (NRF) =	EF/80	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour	
Residence Time	$1/V_{space}$	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0980

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$2,528,093 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$3,721,132 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,523,788 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,528,093 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,721,132 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$5,844 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Is the boiler a fluid-bed boiler?	No
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40 percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05

Plant Elevation: 450 Feet above sea level

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Concentration of reagent as stored (C_{stored})	50 percent*
Denisty of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	50 percent
Number of days reagent is stored ($t_{storage}$)	30 days
Estimated equipment life	15 Years
Select the reagent used	Urea

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25 Percent		
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*		
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0088 $/gallon*		
Electricity ($Cost_{elect}$)	0.210 $/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0980

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	\$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	\$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$477,565 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$611,129 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$1,088,694 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$93,134 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$372,444 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$9,166 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$0 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$2,739 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$82 in 2016 dollars
Direct Annual Cost =		\$477,565 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$2,794 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$608,335 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$611,129 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$1,088,694 per year in 2016 dollars
NOx Removed =	318 tons/year
Cost Effectiveness =	\$3,419 per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.28	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.185	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.20**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection, but not including field installatior
Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284)				
Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)				
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	5.53	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.00	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectio
VOMP ($/MWh) = Q*T*10	=	$	0.423	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**7.96**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 15				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0980	=	$	2,026,363	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**3,072,965**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,356,087**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,914,480**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		456	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**10,785**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.101	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.234	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.461**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.874	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,004,722	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,268,968	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	33,861,344	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,231	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,386,134	Engineering and construction management costs
A2 = 10% of BM	=	$	3,386,134	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,386,134	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,019,747**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,601**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,200,987	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,220,735**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,681**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,622,073	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**50,842,808**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,849**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.73**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	0.88	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.25	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.06**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	853,468	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,016,856	CC Manual
Property tax (1% of total capital investment)	=	$	508,428	CC Manual
Insurance (1% of total capital investment)	=	$	508,428	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	4,981,433	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**7,868,614**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**10,990,629**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,084,456**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		586	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**17,213**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.13	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.236	1.811*K
Aux Power	**M**	**(%)**	**2.079**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.908	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,485,962	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,542,315	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,220,076	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,216,477	Total base cost including retrofit factor
BM ($/kW)	=	$	1,353	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,721,648	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,721,648	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,721,648	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,381,420**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,759**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,419,071	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**50,800,491**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,847**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,080,049.08	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**55,880,540**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,032**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.53	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.14**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.14	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.26	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.37	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**6.78**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	711,875	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,117,611	CC Manual
Property tax (1% of total capital investment)	=	$	558,805	CC Manual
Insurance (1% of total capital investment)	=	$	558,805	CC Manual
Capital Recovery Factor (CRF) = $[\, i\,(1+i)^{n}\,] / [\,(1+i)^{n} - 1\,]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	5,475,016	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	=	**$**	**8,422,112**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**11,241,441**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,314,589**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		644	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**16,005**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix C (Coal Analyses Summary)

Coal Analyses Summary (As Received)					
Year	Report	Coal	HHV	Moisture	Sulfur
Units		(tons)	(btu/lb)	(%)	(%)
2013	A	103,122.35	7,670	27.22	0.15
2013	B	115,917.00	7,599	27.95	0.17
2014	A	117,659.65	7,652	27.89	0.15
2014	B	103,979.45	7,617	27.86	0.14
2015	A	103,904.80	7,599	29.16	0.14
2015	B	120,758.30	7,610	29.02	0.15
2016	A	115,282.20	7,683	31.21	0.12
2016	B	107,687.35	7,604	29.23	0.14
2017	A	106,040.35	7,567	32.20	0.11
2017	B	114,440.00	7,529	32.52	0.10
Weighted average		221,758.29	7,613	29.44	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 6/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	7552	28.06	8.58	36.44	26.93	0.12	TII	V6	6	1,177.90
AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	16906.60	7511.00	28.08	8.95	35.75	27.23	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2013	10	7504	27.93	9.16	34.93	27.98	0.20	T II	T4	4	961.05
AURORA ENERGY LLC	1/3/2013	11	7599	26.87	9.32	35.99	27.83	0.18	P2/STK	C1	6/N	1,000.35
AURORA ENERGY LLC	1/4/2013	9	7685	27.59	8.22	36.39	27.81	0.17	P2/STK	C1	6/N	816.20
AURORA ENERGY LLC	1/5/2013	13	7711	27.47	8.17	36.74	27.63	0.18	P2/STK	C1	6/N	1,263.55
AURORA ENERGY LLC	1/7/2013	11	7612	27.77	8.70	35.41	28.12	0.17	P2/STK	C1	6/N	1,057.50
AURORA ENERGY LLC	1/8/2013	9	7565	26.55	10.25	35.37	27.84	0.17	TII/P2	T4/C1	4/6	858.05
AURORA ENERGY LLC	1/9/2013	12	7584	27.03	9.43	35.53	28.01	0.18	T II/P2	T4/C1	4/6	1,113.90
AURORA ENERGY LLC	1/10/2013	6	7692	25.65	9.78	36.60	27.96	0.17	P2/STK	C1	6/N	562.40
AURORA ENERGY LLC	1/11/2013	13	7507	27.09	10.00	35.86	27.05	0.18	P2/STK	C1	6/N	1,223.50
AURORA ENERGY LLC	1/14/2013	9	7566	26.87	9.70	35.71	27.72	0.16	P2/STK	C1	6/N	872.75
AURORA ENERGY LLC	1/15/2013	14	7632	28.16	8.04	35.42	28.38	0.20	TII	T4	4	1,261.60
AURORA ENERGY LLC	1/16/2013	12	7784	27.66	7.41	36.36	28.57	0.17	TII	T4	4	1,096.85
AURORA ENERGY LLC	1/17/2013	7	7758	27.48	8.08	35.70	28.75	0.19	P2/STK	C1	6/N	645.20
AURORA ENERGY LLC	1/18/2013	11	7788	26.88	7.92	36.52	28.68	0.16	P2/STK	C1	6/N	1,007.45
AURORA ENERGY LLC	1/21/2013	8	7678	26.95	8.63	35.72	28.71	0.17	T II/STK	T4	4/N	737.10
AURORA ENERGY LLC	1/22/2013	13	7709	27.10	8.34	35.59	28.98	0.18	T II/STK	T4	4/N	1,166.85
AURORA ENERGY LLC	1/23/2013	14	7746	27.10	8.39	36.04	28.47	0.17	P2/STK	C1	6/S	1,223.50
AURORA ENERGY LLC	1/25/2013	7	7754	27.88	7.45	36.79	27.89	0.15	P2/STK	C1	6/N	633.50
AURORA ENERGY LLC	1/25/2013	11	7585	26.81	9.72	36.20	27.28	0.15	P2/STK	C1	6/N	994.60
AURORA ENERGY LLC	1/28/2013	9	7484	26.40	11.09	35.58	26.94	0.15	P2/STK	C1	6/S	807.55
AURORA ENERGY LLC	1/29/2013	11	7691	26.62	9.22	36.11	28.05	0.15	P2/STK	C1	6/S	994.45
AURORA ENERGY LLC	1/30/2013	13	7482	28.23	9.21	35.05	27.52	0.16	P2/STK	C1	6/S	1,150.80
AURORA ENERGY LLC	1/31/2013	10	7460	26.87	10.25	34.89	27.99	0.15	TII/P2	T3/C1	3/6	920.60
AURORA ENERGY LLC	2/1/2013	8	7529	28.24	9.08	35.07	27.61	0.14	TII	T3	3	763.65
AURORA ENERGY LLC	2/4/2013	7	7545	28.48	8.71	34.47	28.34	0.13	TII	T3	3	629.95
AURORA ENERGY LLC	2/5/2013	11	7463	28.30	9.56	34.22	27.92	0.14	T II	T3	3	1,015.15
AURORA ENERGY LLC	2/7/2013	8	7491	28.60	8.93	34.76	27.72	0.13	P2/TII	C1/T3	6/3	755.05
AURORA ENERGY LLC	2/8/2013	12	7637	27.97	8.09	36.09	27.86	0.14	P2/TII	C1/T3	6/3	1,113.25
AURORA ENERGY LLC	2/9/2013	12	7740	26.73	8.61	37.24	27.42	0.14	P2	C1	6	1,102.05
AURORA ENERGY LLC	2/11/2013	9	7506	26.87	9.55	35.20	28.38	0.16	T II/P2	T3/C1	3/6	848.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	2/12/2013	15	7649	27.94	8.20	35.09	28.77	0.15	T II	T3	3	1,378.10
AURORA ENERGY LLC	2/13/2013	21	7556	27.99	9.13	34.51	28.38	0.15	T II	T3	3	1,914.10
AURORA ENERGY LLC	2/14/2013	8	7819	26.40	8.38	36.31	28.91	0.14	P2/STK	C1	6/N	701.80
AURORA ENERGY LLC	2/15/2013	15	7437	27.31	10.59	34.59	27.51	0.15	P2/STK	C1	6/S	1,300.35
AURORA ENERGY LLC	2/18/2013	9	7616	27.77	8.69	34.75	28.80	0.14	TII	T3	3	852.10
AURORA ENERGY LLC	2/19/2013	5	8065	26.73	6.36	37.32	29.59	0.13	P2/STK	C1	6/S	448.60
AURORA ENERGY LLC	2/20/2013	18	7824	27.32	7.48	37.11	28.09	0.15	P2/STK	C1	6/S	1,648.60
AURORA ENERGY LLC	2/21/2013	7	7607	26.43	10.17	36.29	27.11	0.15	P2/STK	C1	6/S	615.40
AURORA ENERGY LLC	2/22/2013	15	7510	28.05	9.42	35.26	27.28	0.14	TII	T3	3	1,390.45
AURORA ENERGY LLC	2/25/2013	9	7697	28.21	7.72	34.80	29.27	0.14	TII	T3	3	817.70
AURORA ENERGY LLC	2/26/2013	14	7588	28.23	8.43	35.08	28.26	0.14	TII/P2	T3/C1	3/6	1,275.05
AURORA ENERGY LLC	2/28/2013	17	7872	27.40	6.91	37.27	28.43	0.15	P2/STK	C1	6/S	1,587.05
AURORA ENERGY LLC	3/4/2013	11	7508	26.13	11.00	35.23	27.65	0.15	P2/TII	C1/T3	6/3	1,033.95
AURORA ENERGY LLC	3/5/2013	11	7682	26.99	8.13	36.34	28.55	0.14	P2/STK	C1	6/S	959.30
AURORA ENERGY LLC	3/6/2013	14	7648	27.25	7.96	36.56	28.23	0.15	P2/STK	C1	6/S	1,302.85
AURORA ENERGY LLC	3/7/2013	7	7717	26.40	8.27	37.82	27.53	0.15	P2/STK	C1	6/S	619.15
AURORA ENERGY LLC	3/8/2013	6	7469	26.55	9.86	37.18	26.41	0.16	P2/STK	C1	6/S	538.30
AURORA ENERGY LLC	3/11/2013	11	7857	27.02	7.45	37.34	28.20	0.15	P2/STK	C1	6/S	1,016.00
AURORA ENERGY LLC	3/12/2013	13	7868	26.99	7.27	37.32	28.43	0.14	P2/STK	C1	6/S	1,200.55
AURORA ENERGY LLC	3/13/2013	18	7437	28.70	8.86	35.07	27.37	0.14	P2/STK	C1	6/S	1,586.50
AURORA ENERGY LLC	3/15/2013	7	7253	25.91	13.37	35.02	25.70	0.14	P2/STK	C1	6/S	652.45
AURORA ENERGY LLC	3/19/2013	11	7570	26.44	10.41	36.24	26.91	0.16	P2/STK	C1	6/S	1,034.15
AURORA ENERGY LLC	3/19/2013	8	7723	26.43	9.14	36.80	27.63	0.14	P2/STK	C1	6/S	734.00
AURORA ENERGY LLC	3/20/2013	11	7812	26.67	8.36	36.58	28.40	0.15	P2/STK	C1	6/S	1,058.60
AURORA ENERGY LLC	3/21/2013	3	7805	26.35	8.46	36.75	28.44	0.15	P2/STK	C1	6/S	264.35
AURORA ENERGY LLC	3/22/2013	8	7580	26.59	10.17	36.01	27.24	0.15	P2/STK	C1	6/S	747.60
AURORA ENERGY LLC	3/25/2013	6	7835	26.61	7.98	37.07	28.35	0.15	P2/STK	C1	6/S	545.80
AURORA ENERGY LLC	3/26/2013	10	7873	26.37	7.94	37.21	28.48	0.16	P2/STK	C1	6/S	911.95
AURORA ENERGY LLC	3/27/2013	11	7633	26.67	9.68	35.80	27.86	0.16	P2/STK	C1	6/S	1,011.95
AURORA ENERGY LLC	3/28/2013	4	7776	26.70	8.29	37.09	27.93	0.15	P2/STK	C1	6/S	363.85
AURORA ENERGY LLC	4/1/2013	6	7964	26.30	7.22	37.59	28.89	0.15	P2/STK	C1	6/S	527.90
AURORA ENERGY LLC	4/2/2013	11	[illegible]	[illegible]	[illegible]	[illegible]	29.16	0.15	P2/STK	C1	6/S	993.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	4/3/2013	10	7812	27.29	7.75	36.64	28.33	0.14	P2/STK	C1	6/S	935.20
AURORA ENERGY LLC	4/4/2013	5	7779	26.72	8.53	36.84	27.92	0.14	P2/STK	C1	6/S	458.50
AURORA ENERGY LLC	4/5/2013	9	7866	26.26	8.67	36.80	28.28	0.15	P2/STK	C1	6/N	855.30
AURORA ENERGY LLC	4/8/2013	10	7363	27.30	11.58	34.23	26.89	0.16	P2/JDRC	C1/C13	6/3	934.30
AURORA ENERGY LLC	4/9/2013	14	7381	29.34	8.61	35.20	26.86	0.14	TII	V6	6	1,269.45
AURORA ENERGY LLC	4/11/2013	10	7736	28.34	7.26	36.44	27.97	0.15	TII	V6	6	885.25
AURORA ENERGY LLC	4/11/2013	6	7591	28.62	7.89	36.55	26.95	0.14	TII	V6	6	556.70
AURORA ENERGY LLC	4/16/2013	11	7286	29.40	11.50	32.67	26.44	0.15	JD/GRP	C13	3/C	1,062.00
AURORA ENERGY LLC	4/16/2013	10	7385	29.01	10.61	33.14	27.25	0.17	JDRC	C13	3	939.50
AURORA ENERGY LLC	4/18/2013	8	7746	27.55	7.98	36.17	28.31	0.15	T II	V6	6	730.15
AURORA ENERGY LLC	4/20/2013	8	7783	26.84	9.01	35.88	28.28	0.16	T II/STK	V6	6/W	750.40
AURORA ENERGY LLC	4/22/2013	7	7659	27.90	8.10	36.27	27.74	0.16	T II/STK	V6	6/W	657.70
AURORA ENERGY LLC	4/23/2013	8	7706	27.47	8.38	36.53	27.61	0.16	T II/STK	V6	6/W	741.05
AURORA ENERGY LLC	4/25/2013	9	7589	27.83	8.91	36.03	27.24	0.15	T II	V6	6	856.65
AURORA ENERGY LLC	4/25/2013	7	7505	26.90	10.26	36.16	26.69	0.14	TII	V6	6	640.30
AURORA ENERGY LLC	4/26/2013	8	7601	27.54	8.54	37.23	26.69	0.15	TII	V6	6	746.30
AURORA ENERGY LLC	4/29/2013	10	7495	28.32	8.82	35.78	27.09	0.14	T II	V6	6	915.65
AURORA ENERGY LLC	4/30/2013	12	7123	27.64	12.55	34.60	25.21	0.14	T II	V6	6	1,130.20
AURORA ENERGY LLC	5/1/2013	12	7962	24.90	11.11	35.05	28.95	0.17	GRP/STK		M/N	1,238.65
AURORA ENERGY LLC	5/2/2013	10	7815	25.21	11.77	34.52	28.51	0.17	GRP/STK		M/S	940.15
AURORA ENERGY LLC	5/3/2013	7	7574	25.05	13.91	33.39	27.66	0.18	GRP/STK		M/S	670.35
AURORA ENERGY LLC	5/3/2013	13	8042	24.57	11.80	34.49	29.14	0.18	GRP/STK		M/S	1,223.00
AURORA ENERGY LLC	5/6/2013	3	8200	23.89	10.98	34.73	30.41	0.19	GRP/STK		M/N	278.80
AURORA ENERGY LLC	5/20/2013	8	7876	26.05	9.72	36.04	28.19	0.16	GRP/STK		M/N	765.10
AURORA ENERGY LLC	5/21/2013	16	8437	24.71	8.98	35.53	30.78	0.18	GRP/STK		M/N	1,459.45
AURORA ENERGY LLC	5/23/2013	10	8746	23.37	8.77	35.33	32.54	0.18	GRP		M	954.30
AURORA ENERGY LLC	5/23/2013	11	8414	24.03	9.96	34.57	31.45	0.17	GRP		M	1,064.60
AURORA ENERGY LLC	5/27/2013	9	8508	23.93	9.27	35.49	31.31	0.18	GRP/STK		M/N	819.70
AURORA ENERGY LLC	5/28/2013	12	8514	24.06	9.27	35.30	31.38	0.18	GRP/STK		M/N	1,151.15
AURORA ENERGY LLC	5/30/2013	10	7619	27.91	8.56	36.48	27.05	0.13	T II	V6	6	956.70
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	[illegible]	[illegible]	[illegible]	[illegible]	26.93	0.12	TII	V6	6	1,177.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103122.35	7670.00	27.22	9.05	35.76	27.98	0.15

This analysis is representative of the coal shipped using sulfur standard ASTM D4239-12

Coleen Thompson

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2013	7	7360	26.50	11.80	35.40	26.30	0.15	TBR	C1	6	652.55
AURORA ENERGY LLC	7/2/2013	21	7675	26.40	9.51	36.33	27.77	0.15	TBR	C1	6	1,961.70
AURORA ENERGY LLC	7/5/2013	23	7565	27.34	9.39	34.94	28.34	0.19	T II	U4	4	2,171.90
AURORA ENERGY LLC	7/8/2013	10	7538	28.53	8.36	34.23	28.88	0.19	TII	U4	4	917.50
AURORA ENERGY LLC	7/9/2013	29	7645	28.51	7.49	35.44	28.57	0.16	T II	U4	4	2,700.95
AURORA ENERGY LLC	7/11/2013	13	7502	28.50	8.82	35.62	27.06	0.18	TBR	C1	6	1,224.95
AURORA ENERGY LLC	7/15/2013	12	7485	29.53	7.66	35.01	27.81	0.19	TII	U4	4	1,067.35
AURORA ENERGY LLC	7/16/2013	11	7317	27.95	10.29	34.12	27.68	0.25	T II	U4	4	1,019.50
AURORA ENERGY LLC	7/22/2013	11	7609	28.80	7.97	34.86	28.37	0.18	TII	U4	4	1,018.45
AURORA ENERGY LLC	7/24/2013	25	7467	28.43	8.50	34.68	28.41	0.19	T II	U4	4	2,303.20
AURORA ENERGY LLC	7/25/2013	13	7416	28.52	9.36	34.76	27.37	0.20	TII	U4	4	1,239.20
AURORA ENERGY LLC	7/29/2013	9	7339	29.30	9.16	33.88	27.67	0.20	T II	U4	4	836.20
AURORA ENERGY LLC	8/1/2013	27	7749	27.87	8.65	34.52	28.97	0.15	JR/GRP	C13	4/M	2,483.15
AURORA ENERGY LLC	8/5/2013	10	7833	27.43	9.00	34.23	29.35	0.17	JD/GRP	C13	4/M	948.40
AURORA ENERGY LLC	8/6/2013	18	7752	29.20	7.09	34.40	29.31	0.14	JR/GRP	C13	4/M	1,657.00
AURORA ENERGY LLC	8/8/2013	12	7737	28.58	7.91	34.30	29.22	0.14	JR/GRP	C13	4/M	1,172.25
AURORA ENERGY LLC	8/8/2013	16	7648	28.65	8.33	34.49	28.53	0.13	JR/GRP	C13	4/M	1,524.25
AURORA ENERGY LLC	8/9/2013	12	7552	28.48	8.20	35.34	27.99	0.20	TII	U4	4	1,085.70
AURORA ENERGY LLC	8/12/2013	7	7610	28.79	7.51	34.66	29.05	0.16	TII	U4	4	657.40
AURORA ENERGY LLC	8/13/2013	17	7503	29.40	8.11	34.39	28.11	0.15	JR/T II	C13/U4	4/4	1,550.05
AURORA ENERGY LLC	8/19/2013	9	7696	28.53	8.03	34.46	29.00	0.16	JR	C13	4	834.85
AURORA ENERGY LLC	8/20/2013	17	7764	28.71	7.65	34.86	28.79	0.14	JR/GRP	C13	4/M	1,569.00
AURORA ENERGY LLC	8/22/2013	11	8309	24.18	10.01	34.82	31.00	0.20	GRP/STK		M/N	1,008.60
AURORA ENERGY LLC	8/22/2013	15	8288	24.11	9.99	35.32	30.58	0.17	GRP/STK		M/N	1,412.05
AURORA ENERGY LLC	8/26/2013	5	7656	27.01	10.63	33.80	28.57	0.19	T II/GRP	U3	3/M	491.15
AURORA ENERGY LLC	8/27/2013	12	7557	27.38	10.91	33.44	28.26	0.15	T II/GRP	U3	3/M	1,141.90
AURORA ENERGY LLC	8/28/2013	10	7705	27.60	9.20	34.46	28.74	0.14	T II/GRP	U3	3/M	905.40
AURORA ENERGY LLC	8/29/2013	12	7822	26.89	10.18	34.14	28.79	0.15	TII/GRP	U3	3/M	1,149.70
AURORA ENERGY LLC	9/3/2013	11	7996	26.39	10.28	34.01	29.33	0.16	TII/GRP	U3	3/M	1,048.10
AURORA ENERGY LLC	9/5/2013	10	7654	26.76	10.82	33.81	28.61	0.15	T II/GRP	U3	3/M	935.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	9/5/2013	12	7566	28.02	8.70	34.71	28.58	0.12	T II	U3	3	1,051.50
AURORA ENERGY LLC	9/7/2013	9	7584	28.16	8.73	35.10	28.01	0.12	T II	U3	3	808.00
AURORA ENERGY LLC	9/9/2013	5	7525	28.89	8.44	34.02	28.66	0.13	T II	U3	3	479.85
AURORA ENERGY LLC	9/11/2013	20	6894	29.54	12.49	32.88	25.09	0.13	JR	C13	3	1,938.20
AURORA ENERGY LLC	9/13/2013	20	7578	27.99	8.74	34.77	28.50	0.13	TII/STK	U3	3/N	1,900.70
AURORA ENERGY LLC	9/16/2013	8	7507	27.68	9.36	34.53	28.43	0.12	TII	U3	3	769.35
AURORA ENERGY LLC	9/18/2013	12	7474	28.91	8.87	34.24	27.99	0.13	T II	U3	3	1,134.85
AURORA ENERGY LLC	9/19/2013	18	7447	28.38	9.45	34.11	28.06	0.12	T II	U3	3	1,756.50
AURORA ENERGY LLC	9/20/2013	15	7567	28.36	8.52	34.37	28.75	0.12	T II	U3	3	1,459.60
AURORA ENERGY LLC	9/24/2013	21	7503	27.57	9.98	35.65	26.81	0.15	TBR	C1	6	2,034.85
AURORA ENERGY LLC	9/25/2013	15	7615	26.60	9.92	36.33	27.16	0.15	TBR	C1	6	1,425.25
AURORA ENERGY LLC	9/26/2013	13	7626	26.57	9.47	37.08	26.88	0.15	TBR	C1	6	1,261.65
AURORA ENERGY LLC	9/30/2013	6	7556	26.97	10.47	35.62	26.95	0.15	TBR	C1	6	572.95
AURORA ENERGY LLC	10/2/2013	8	7354	27.62	11.21	33.98	27.20	0.18	TBR	C1	6	758.30
AURORA ENERGY LLC	10/7/2013	11	7515	27.82	9.13	34.36	28.69	0.16	T II	V4	4	1,009.45
AURORA ENERGY LLC	10/10/2013	23	7298	28.57	10.30	33.77	27.36	0.15	T II	V4	4	2,203.90
AURORA ENERGY LLC	10/11/2013	17	7295	28.25	10.17	34.26	27.32	0.21	TII	V4	4	1,618.40
AURORA ENERGY LLC	10/15/2013	13	7770	27.43	8.67	34.47	29.43	0.21	T II	V4	4	1,250.95
AURORA ENERGY LLC	10/16/2013	9	7622	28.16	8.19	34.71	28.94	0.18	T II	V4	4	834.60
AURORA ENERGY LLC	10/17/2013	16	7560	28.73	7.77	34.73	28.78	0.19	T II	V4	4	1,448.90
AURORA ENERGY LLC	10/18/2013	13	7582	27.73	7.91	35.43	28.93	0.18	TII	V4	4	1,209.15
AURORA ENERGY LLC	10/21/2013	15	7584	27.84	9.19	34.45	28.53	0.20	T II	V4	4	1,476.80
AURORA ENERGY LLC	10/22/2013	13	7492	28.05	9.43	34.58	27.95	0.20	T II	V4	4	1,280.80
AURORA ENERGY LLC	10/23/2013	18	7557	28.26	8.52	34.70	28.52	0.20	T II	V4	4	1,756.85
AURORA ENERGY LLC	10/26/2013	14	7539	27.86	9.52	34.75	27.88	0.20	T II/T II	V4/W4	4/4	1,307.25
AURORA ENERGY LLC	10/28/2013	13	7536	27.75	9.19	34.92	28.15	0.20	TII	W4	4	1,171.30
AURORA ENERGY LLC	10/29/2013	12	7871	28.27	5.87	35.86	30.00	0.14	Bdl	Bx	3	1,070.25
AURORA ENERGY LLC	10/30/2013	13	7644	27.59	8.16	34.73	29.52	0.12	Bdl	C4	3	1,251.70
AURORA ENERGY LLC	11/2/2013	17	7709	28.33	7.68	35.49	28.50	0.15	T II	W4	4	1,561.60
AURORA ENERGY LLC	11/4/2013	9	7745	28.25	7.16	35.46	29.13	0.17	Bdl	C4	3	828.45
AURORA ENERGY LLC	11/5/2013	11	7603	28.42	8.04	34.70	28.84	0.16	T II	W4	4	1,007.45
AURORA ENERGY LLC	11/6/2013	14	7565	28.35	8.34	[illegible]	28.52	0.18	T II	W4	4	1,280.20

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	11/7/2013	11	7677	28.65	6.91	35.74	28.70	0.13	T II	W4	4	939.25
AURORA ENERGY LLC	11/8/2013	8	7833	27.17	7.05	36.48	29.30	0.13	Bdl	C4	3	726.25
AURORA ENERGY LLC	11/12/2013	13	7498	28.03	9.12	34.66	28.19	0.21	TII	W4	4	1,230.50
AURORA ENERGY LLC	11/13/2013	17	7622	28.11	7.98	34.84	29.08	0.20	T II	W4	4	1,615.85
AURORA ENERGY LLC	11/14/2013	15	7466	27.50	9.91	34.21	28.39	0.21	TII	W4	4	1,368.50
AURORA ENERGY LLC	11/15/2013	12	7512	28.08	8.72	34.44	28.78	0.20	TII	W4	4	1,137.60
AURORA ENERGY LLC	11/18/2013	12	7497	27.70	9.39	34.26	28.65	0.21	TII	W4	4	1,169.75
AURORA ENERGY LLC	11/19/2013	13	7183	26.91	12.26	33.66	27.18	0.23	TII	W4	4	1,238.50
AURORA ENERGY LLC	11/20/2013	10	7196	27.55	12.16	33.17	27.13	0.25	T II	W4	4	928.10
AURORA ENERGY LLC	11/21/2013	3	7305	27.84	11.04	33.48	27.65	0.25	T II	W4	4	282.10
AURORA ENERGY LLC	11/22/2013	9	7444	28.14	9.57	34.53	27.77	0.22	TII	W4	4	853.00
AURORA ENERGY LLC	11/23/2013	25	7557	28.84	7.91	34.72	28.54	0.19	TII	W4	4	2,370.10
AURORA ENERGY LLC	11/26/2013	3	7521	28.65	8.47	34.71	28.18	0.20	TII	W4	4	292.95
AURORA ENERGY LLC	11/27/2013	14	7453	28.74	9.06	34.31	27.89	0.20	TII	W4	4	1,322.45
AURORA ENERGY LLC	11/29/2013	10	7658	27.34	8.86	34.71	29.09	0.16	TII/STK	W4	3/N	946.40
AURORA ENERGY LLC	12/2/2013	17	7630	28.09	8.37	34.99	28.56	0.18	TII	W4	4	1,494.70
AURORA ENERGY LLC	12/3/2013	10	7595	28.49	8.08	34.80	28.63	0.20	T II	W4	4	869.90
AURORA ENERGY LLC	12/4/2013	10	7734	27.36	7.78	35.11	29.76	0.17	T II	W4	4	904.75
AURORA ENERGY LLC	12/5/2013	8	7810	27.74	6.95	35.21	30.10	0.13	Bdl	C4	3	763.85
AURORA ENERGY LLC	12/9/2013	11	7711	27.99	7.91	34.53	29.57	0.13	Bdl/TII	C4/W4	3/4	1,063.85
AURORA ENERGY LLC	12/10/2013	13	7739	27.62	7.73	34.74	29.92	0.13	Bdl	C4	3	1,275.10
AURORA ENERGY LLC	12/11/2013	9	7674	27.46	8.60	34.24	29.71	0.13	Bdl	C4	3	881.40
AURORA ENERGY LLC	12/13/2013	3	7696	27.89	8.39	34.21	29.51	0.11	Bdl/STK	C4	3/N	286.75
AURORA ENERGY LLC	12/16/2013	9	7702	27.46	8.54	34.06	29.94	0.12	Bdl	C4	3	852.80
AURORA ENERGY LLC	12/17/2013	8	7800	27.48	7.89	34.58	30.05	0.13	Bdl	C4	4	776.85
AURORA ENERGY LLC	12/18/2013	12	7960	27.33	6.37	35.46	30.85	0.13	Bdl	C4	3	1,176.55
AURORA ENERGY LLC	12/19/2013	10	7856	28.26	6.73	34.92	30.10	0.12	Bdl	C4	3	966.55
AURORA ENERGY LLC	12/20/2013	7	7801	27.63	7.58	34.88	29.92	0.13	Bdl/STK	C4	3/N	669.90
AURORA ENERGY LLC	12/23/2013	15	7802	28.04	7.12	34.75	30.09	0.12	Bdl/STK	C4	3/N	1,473.00
AURORA ENERGY LLC	12/24/2013	15	7676	27.81	8.37	34.17	29.65	0.15	Bdl/STK	C4	3/N	1,459.65
AURORA ENERGY LLC	12/27/2013	5	7632	28.24	8.14	35.09	28.53	0.19	TII	X4	4	431.00
AURORA ENERGY LLC	12/27/2013	6	[illegible]	[illegible]	[illegible]	[illegible]	27.70	0.22	TII	X4	4	547.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	12/29/2013	27	7744	27.93	7.68	35.17	29.23	0.17	TII	X4	4	2,307.45
AURORA ENERGY LLC	12/30/2013	10	7520	27.94	9.09	34.77	28.20	0.22	T II	X4	4	942.95
AURORA ENERGY LLC	12/31/2013	8	7602	27.77	8.55	34.81	28.87	0.22	T II	X4	4	744.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115917.70	7599.00	27.95	8.81	34.72	28.53	0.17

This analysis is representative of the coal shipped using sulfur standard ASTM D4239-12

Coleen Thompson
1-3-14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2014	15	7592	27.80	8.87	34.55	28.78	0.20	T II	X4	4	1,370.90
AURORA ENERGY LLC	1/3/2014	15	7615	29.16	7.32	35.00	28.52	0.17	TII	X4	4	1,440.35
AURORA ENERGY LLC	1/6/2014	8	7633	28.42	7.70	34.85	29.03	0.16	T II	X4	4	779.40
AURORA ENERGY LLC	1/7/2014	12	7642	28.93	7.31	34.80	28.97	0.17	TII	X4	4	1,137.10
AURORA ENERGY LLC	1/8/2014	13	7615	28.31	8.20	34.76	28.74	0.19	T II	X4	4	1,229.35
AURORA ENERGY LLC	1/9/2014	11	7538	28.03	8.94	34.41	28.63	0.23	T II	X4	4	1,070.75
AURORA ENERGY LLC	1/10/2014	13	7571	28.86	8.02	34.63	28.49	0.18	TII	X4	4	1,216.15
AURORA ENERGY LLC	1/13/2014	10	7453	27.84	9.86	34.82	27.48	0.22	TII	X4	4	984.25
AURORA ENERGY LLC	1/14/2014	11	7489	28.42	8.99	34.32	28.27	0.22	Bdl	C4	3	1,031.80
AURORA ENERGY LLC	1/15/2014	8	7608	28.12	8.69	34.32	28.87	0.20	T II	X4	4	756.60
AURORA ENERGY LLC	1/16/2014	13	7588	28.25	8.55	34.40	28.80	0.20	T II	X4	4	1,251.05
AURORA ENERGY LLC	1/18/2014	16	7679	29.63	6.32	34.82	29.24	0.14	TII	X4	4	1,478.00
AURORA ENERGY LLC	1/20/2014	10	7735	28.53	7.06	34.71	29.71	0.16	T II	X4	4	953.85
AURORA ENERGY LLC	1/21/2014	9	7833	28.40	6.48	34.96	30.17	0.13	Bdl	C4	3	805.85
AURORA ENERGY LLC	1/22/2014	12	7767	27.95	7.35	34.72	29.99	0.13	Bdl	C4	3	1,168.20
AURORA ENERGY LLC	1/23/2014	3	7759	28.53	7.30	34.21	29.97	0.13	Bdl	C4	3	293.50
AURORA ENERGY LLC	1/27/2014	9	7379	28.65	9.78	33.16	28.41	0.12	Bdl/JR	C4/C13	3/3	853.10
AURORA ENERGY LLC	1/28/2014	9	7700	28.25	7.82	34.50	29.43	0.15	Bdl/JR	C4/C13	3/3	810.95
AURORA ENERGY LLC	1/29/2014	10	7721	28.70	7.00	34.48	29.82	0.14	Bdl/STK	C4	3/N	917.25
AURORA ENERGY LLC	1/30/2014	15	7737	28.41	7.34	34.81	29.44	0.13	Bdl	C4	3	1,357.75
AURORA ENERGY LLC	1/31/2014	22	7529	29.01	8.13	33.66	29.21	0.12	Bdl	C4	3	2,046.90
AURORA ENERGY LLC	2/3/2014	19	7560	28.92	8.26	33.56	29.26	0.14	Bdl	C4	3	1,809.10
AURORA ENERGY LLC	2/4/2014	12	7527	29.18	8.14	33.53	29.14	0.13	Bdl/ T II	C4/X3	3/3	1,138.90
AURORA ENERGY LLC	2/5/2014	6	7533	28.73	8.62	34.00	28.66	0.13	TII	X3	3	549.45
AURORA ENERGY LLC	2/6/2014	9	7582	28.26	8.89	33.92	28.93	0.12	T II	X3	3	833.35
AURORA ENERGY LLC	2/10/2014	11	7548	28.78	8.49	33.65	29.08	0.13	T II	X3	3	997.40
AURORA ENERGY LLC	2/12/2014	13	7669	28.02	8.03	34.85	29.10	0.13	T II	X3	3	1,178.00
AURORA ENERGY LLC	2/12/2014	8	7568	27.51	9.42	34.40	28.68	0.12	T II	X3	3	735.35
AURORA ENERGY LLC	2/13/2014	12	7810	26.92	8.17	35.24	29.67	0.19	Bdl	A	4	1,085.25
AURORA ENERGY LLC	2/15/2014	10	7841	26.99	7.79	36.16	29.07	0.21	Bdl	A	4	964.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	2/17/2014	8	7821	26.21	8.59	36.19	29.02	0.26	Bdl	A	4	771.90
AURORA ENERGY LLC	2/18/2014	12	7857	26.05	8.45	35.90	29.61	0.23	Bdl	A	4	1,099.50
AURORA ENERGY LLC	2/19/2014	16	7803	26.19	8.75	35.91	29.15	0.21	Bdl/STK	A	4/N	1,524.75
AURORA ENERGY LLC	2/20/2014	7	7738	26.33	9.11	35.75	28.82	0.20	Bdl/STK	A	4/N	670.45
AURORA ENERGY LLC	2/21/2014	18	7702	26.91	8.70	35.77	28.63	0.20	Bdl/STK	A	4/N	1,716.05
AURORA ENERGY LLC	2/24/2014	13	7721	27.34	8.35	35.25	29.07	0.19	Bdl/STK	A	4/N	1,244.25
AURORA ENERGY LLC	2/25/2014	14	7663	27.53	8.50	34.81	29.15	0.15	TII/Bdl	X3/A	3/4	1,314.15
AURORA ENERGY LLC	2/27/2014	18	7704	27.80	7.88	35.13	29.20	0.14	T II	X3	3	1,743.25
AURORA ENERGY LLC	2/28/2014	19	7519	28.26	8.83	34.59	28.33	0.13	Bdl/T II	A/X3	4/3	1,856.75
AURORA ENERGY LLC	3/3/2014	11	7539	28.91	8.17	33.90	29.03	0.11	TII/Bdl	X3/A	3/4	1,078.75
AURORA ENERGY LLC	3/4/2014	13	7678	26.91	9.19	35.01	28.89	0.23	Bdl/STK	B	4/N	1,195.00
AURORA ENERGY LLC	3/5/2014	11	7784	26.75	8.53	35.75	28.96	0.21	Bdl/STK	B	4/N	1,084.80
AURORA ENERGY LLC	3/6/2014	7	7723	26.83	8.71	35.41	29.05	0.18	Bdl/STK	B	4/N	691.95
AURORA ENERGY LLC	3/7/2014	7	7758	26.72	8.49	35.58	29.20	0.19	Bdl/STK	B	4/N	666.20
AURORA ENERGY LLC	3/10/2014	7	7719	26.52	9.09	35.53	28.86	0.22	Bdl/STK	B	4/N	671.50
AURORA ENERGY LLC	3/11/2014	11	7675	27.64	8.15	35.24	28.97	0.20	Bdl/STK	B	4/N	1,016.05
AURORA ENERGY LLC	3/12/2014	4	7634	27.35	8.82	35.17	28.66	0.21	Bdl/STK	B	4/N	394.50
AURORA ENERGY LLC	3/13/2014	16	7120	26.15	14.55	33.06	26.25	0.25	Bdl/STK	B	4/N	1,555.45
AURORA ENERGY LLC	3/14/2014	12	7615	27.55	9.03	34.97	28.45	0.18	Bdl/STK	B	4/N	1,178.10
AURORA ENERGY LLC	3/17/2014	3	7872	26.97	7.37	36.05	29.62	0.18	Bdl	B	4	281.15
AURORA ENERGY LLC	3/18/2014	12	7750	27.82	7.64	34.83	29.70	0.16	Bdl/STK	B	4/N	1,093.55
AURORA ENERGY LLC	3/19/2014	12	7798	27.45	7.40	35.78	29.38	0.18	Bdl/STK	B	4/N	1,128.70
AURORA ENERGY LLC	3/20/2014	10	7948	26.46	7.32	36.57	29.84	0.23	Bdl/STK	B	4/N	951.45
AURORA ENERGY LLC	3/21/2014	12	7916	27.92	6.00	35.87	30.22	0.12	Bdl	B	4	1,075.20
AURORA ENERGY LLC	3/24/2014	12	7882	27.38	6.81	35.69	15.13	0.14	Bdl/STK	B	4/N	1,043.95
AURORA ENERGY LLC	3/25/2014	1	8057	26.46	6.27	36.20	31.04	0.13	Bdl/STK	B	4/N	85.90
AURORA ENERGY LLC	3/26/2014	15	7887	27.68	6.78	35.65	29.90	0.12	Bdl/T II	B/X3	4/3	1,414.80
AURORA ENERGY LLC	3/27/2014	26	7482	27.96	9.07	34.76	28.21	0.11	TII	X3	3	2,390.75
AURORA ENERGY LLC	3/31/2014	8	7310	27.68	11.54	33.38	27.41	0.13	T II	X3	3	783.60
AURORA ENERGY LLC	4/1/2014	9	7832	28.80	5.23	35.61	30.37	0.10	Bdl	A	3	825.10
AURORA ENERGY LLC	4/2/2014	13	7776	28.29	5.87	35.47	30.37	0.11	Bdl/STK	A	3/N	1,226.70
AURORA ENERGY LLC	4/3/2014	9	7549	27.52	8.97	34.22	29.30	0.13	Bdl/STK	A	3/N	892.80

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	4/4/2014	5	7695	28.07	7.91	34.98	29.05	0.11	T II/Bdl	X3/A	3/3	486.30
AURORA ENERGY LLC	4/7/2014	10	7899	28.09	5.97	35.24	30.71	0.12	Bdl	A	3	913.65
AURORA ENERGY LLC	4/8/2014	10	7861	28.29	6.32	34.97	30.43	0.12	Bdl/STK	A	3/N	951.00
AURORA ENERGY LLC	4/9/2014	14	7878	27.84	6.59	35.28	30.30	0.12	Bdl/STK	A	3/N	1,358.65
AURORA ENERGY LLC	4/10/2014	13	7734	28.36	7.47	34.44	29.73	0.12	Bdl/STK	A	3/N	1,286.85
AURORA ENERGY LLC	4/11/2014	9	7609	28.55	8.22	34.50	28.74	0.12	Bdl/STK	A	3/N	866.30
AURORA ENERGY LLC	4/14/2014	10	7769	27.99	7.38	34.83	29.80	0.11	Bdl/STK	A	3/N	938.10
AURORA ENERGY LLC	4/15/2014	12	7662	28.55	7.20	36.80	27.46	0.13	T II	LST	6	1,108.05
AURORA ENERGY LLC	4/16/2014	11	7262	27.55	11.33	35.30	25.83	0.13	T II	LST	6	950.55
AURORA ENERGY LLC	4/17/2014	13	7462	28.02	9.11	36.75	26.14	0.10	TII	LST	6	1,131.00
AURORA ENERGY LLC	4/18/2014	13	7632	29.53	4.91	36.14	29.42	0.07	Bdl/STK	A	3/N	1,247.60
AURORA ENERGY LLC	4/21/2014	9	7627	27.72	7.25	35.32	29.71	0.11	Bdl/STK	B	3/N	832.25
AURORA ENERGY LLC	4/22/2014	11	7451	27.99	9.12	35.47	27.43	0.13	T II	LST	6	1,070.80
AURORA ENERGY LLC	4/23/2014	11	7525	28.07	8.16	35.70	28.07	0.12	Bdl/STK	B	3/N	999.30
AURORA ENERGY LLC	4/24/2014	12	7570	28.32	8.11	36.21	27.36	0.12	T II	LST	6	1,162.05
AURORA ENERGY LLC	4/25/2014	13	7464	28.40	8.61	36.49	26.51	0.13	TII	LST	6	1,204.30
AURORA ENERGY LLC	4/28/2014	11	7451	27.57	9.55	35.68	27.20	0.13	T II	LST	6	1,083.20
AURORA ENERGY LLC	4/30/2014	12	7397	27.69	9.76	36.58	25.97	0.12	TII	LST	6	1,093.95
AURORA ENERGY LLC	5/1/2014	12	7464	27.86	9.03	36.29	26.82	0.13	TII	LST	6	1,094.60
AURORA ENERGY LLC	5/5/2014	11	7601	28.24	8.15	36.22	27.39	0.14	T II	LST	6	994.65
AURORA ENERGY LLC	5/6/2014	10	7735	27.79	7.63	36.55	28.04	0.14	T II	LST	6	906.90
AURORA ENERGY LLC	5/7/2014	12	7638	28.23	7.46	36.83	27.49	0.13	T II	LST	6	1,121.35
AURORA ENERGY LLC	5/8/2014	14	7544	28.57	8.21	35.22	28.00	0.13	T II/Bsl	LST/A	6/3	1,403.70
AURORA ENERGY LLC	5/12/2014	16	7796	27.50	8.05	35.31	29.14	0.13	Bdl/STK	A	3/N	1,548.15
AURORA ENERGY LLC	5/14/2014	12	7746	28.25	6.78	37.35	27.62	0.12	Bdl/TII	A/LST	3/6	1,055.15
AURORA ENERGY LLC	5/15/2014	9	7712	28.25	7.12	37.35	27.28	0.12	Bdl/TII	A/LST	3/6	858.05
AURORA ENERGY LLC	5/16/2014	10	7707	27.99	7.76	36.08	28.18	0.11	TII/Bdl	LST/A	6/3	974.80
AURORA ENERGY LLC	5/19/2014	8	7769	26.93	7.92	35.48	29.68	0.13	TII/Bdl	LST/B	6/3	769.15
AURORA ENERGY LLC	5/20/2014	11	7915	28.22	6.07	35.62	30.10	0.11	Bdl/STK	B	3/N	1,041.70
AURORA ENERGY LLC	5/21/2014	9	7761	27.26	8.12	35.07	29.56	0.12	Bdl/STK	B	3/N	891.85
AURORA ENERGY LLC	5/22/2014	7	7809	27.38	7.27	35.93	29.43	0.11	Bdl/STK	B	3/N	693.85
AURORA ENERGY LLC	5/23/2014	8	[illegible]	[illegible]	[illegible]	[illegible]	26.52	0.12	TII	LST	6	724.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	5/26/2014	7	7723	28.31	6.78	38.02	26.90	0.12	TII	LST	6	614.05
AURORA ENERGY LLC	5/28/2014	14	7654	26.98	8.94	35.73	28.36	0.12	Bdl/STK	B	3/N	1,342.05
AURORA ENERGY LLC	5/29/2014	12	7514	27.86	9.02	34.63	28.50	0.13	Bdl/STK	B	3/N	1,174.15
AURORA ENERGY LLC	5/30/2014	12	7673	27.44	8.50	34.98	29.08	0.11	Bdl/STK	B	3/N	1,150.20
AURORA ENERGY LLC	6/2/2014	8	7688	27.53	8.31	34.79	29.39	0.11	Bdl/STK	B	3/N	793.70
AURORA ENERGY LLC	6/3/2014	8	7949	27.23	6.72	36.14	29.91	0.11	Bdl/STK	B	3/N	779.60
AURORA ENERGY LLC	6/5/2014	13	7690	28.12	7.45	36.87	27.56	0.13	T II	LST	6	1,236.80
AURORA ENERGY LLC	6/9/2014	5	7676	28.30	7.60	36.90	27.20	0.12	T II	LST	6	481.65
AURORA ENERGY LLC	6/11/2014	7	7704	26.60	10.00	35.94	27.47	0.14	T II/GRP	LST	6/M	683.90
AURORA ENERGY LLC	6/12/2014	5	7669	27.41	8.70	37.27	26.62	0.11	GRP/TII	LST	M/6	489.40
AURORA ENERGY LLC	6/16/2014	10	7632	27.40	8.88	36.76	26.96	0.12	T II	LST	6	964.10
AURORA ENERGY LLC	6/18/2014	16	7672	27.62	7.90	37.02	27.47	0.12	T II	LST	6	1,534.80
AURORA ENERGY LLC	6/19/2014	18	7458	27.53	9.65	36.66	26.16	0.11	TII	LST	6	1,681.40
AURORA ENERGY LLC	6/23/2014	9	7311	28.02	10.34	35.77	25.87	0.15	T II	LST	6	867.60
AURORA ENERGY LLC	6/24/2014	10	7712	27.76	8.03	34.70	29.51	0.12	Bdl/STK	C	3/N	931.05
AURORA ENERGY LLC	6/25/2014	13	7751	28.21	7.20	34.95	29.64	0.11	Bdl/STK	C	3/N	1,259.45
AURORA ENERGY LLC	6/26/2014	12	7776	27.04	7.86	35.66	29.45	0.11	Bdl/STK	C	3/N	1,172.35
AURORA ENERGY LLC	6/30/2014	9	7695	28.75	7.46	34.73	29.06	0.11	Bdl/STK	C	3/N	829.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	117659.65	7652.00	27.89	8.15	35.29	28.54	0.15

This analysis is representative of the coal shipped using sulfur standard ASTM D4239 - 12

Colleen Thompson
7-2-14

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2014	17	7525	28.93	8.28	34.19	28.60	0.12	Bdl/STK	C	3/N	1,638.75
AURORA ENERGY LLC	7/2/2014	11	7442	29.33	8.64	34.80	27.23	0.13	Bdl/STK	C	3/N	1,079.80
AURORA ENERGY LLC	7/4/2014	7	7656	27.98	8.07	36.98	26.97	0.11	TII	LST	6	627.85
AURORA ENERGY LLC	7/7/2014	13	7622	28.13	7.79	37.11	26.97	0.12	T II	LST	6	1,239.90
AURORA ENERGY LLC	7/9/2014	33	7578	28.14	8.43	36.77	26.67	0.13	T II	LST	6	3,141.00
AURORA ENERGY LLC	7/14/2014	13	7395	27.68	9.60	36.03	26.72	0.13	T II	LST	6	1,276.45
AURORA ENERGY LLC	7/16/2014	18	7619	28.26	7.73	36.94	27.08	0.12	T II	LST	6	1,699.05
AURORA ENERGY LLC	7/17/2014	18	7570	28.11	8.29	36.76	26.84	0.12	T II	LST	6	1,778.65
AURORA ENERGY LLC	7/21/2014	14	7442	28.16	9.30	36.11	26.43	0.13	T II	LST	6	1,346.20
AURORA ENERGY LLC	7/23/2014	16	7409	28.35	9.31	36.18	26.16	0.12	T II	LST	6	1,446.00
AURORA ENERGY LLC	7/24/2014	17	7621	27.21	8.61	37.30	26.88	0.11	TII	LST	6	1,544.95
AURORA ENERGY LLC	7/28/2014	5	7539	27.66	8.85	36.81	26.69	0.12	T II	LST	6	490.95
AURORA ENERGY LLC	7/30/2014	6	7675	26.58	9.28	36.70	27.45	0.14	Bdl	C1	6	569.15
AURORA ENERGY LLC	8/4/2014	8	7404	29.01	8.95	35.65	26.39	0.13	T II	LST	6	795.30
AURORA ENERGY LLC	8/5/2014	8	7750	27.08	8.18	37.34	27.40	0.13	TBR	C1	6	703.80
AURORA ENERGY LLC	8/6/2014	17	7586	26.84	9.66	36.79	26.71	0.14	TBR	C1	6	1,686.45
AURORA ENERGY LLC	8/7/2014	13	7425	27.57	10.25	36.28	25.91	0.13	TBR	C1	6	1,299.70
AURORA ENERGY LLC	8/11/2014	8	7702	27.08	8.56	36.95	27.42	0.13	TBR	C1	6	781.45
AURORA ENERGY LLC	8/13/2014	18	7601	26.69	9.52	36.64	27.16	0.13	TBR	C1	6	1,605.50
AURORA ENERGY LLC	8/14/2014	16	7510	26.42	10.35	36.71	26.53	0.12	TBR	C1	6	1,500.05
AURORA ENERGY LLC	8/16/2014	10	7952	25.09	10.53	36.52	27.87	0.19	GRP/STK		M/N	937.00
AURORA ENERGY LLC	8/18/2014	4	7846	25.81	10.48	35.39	28.33	0.17	GRP/STK		M/N	403.90
AURORA ENERGY LLC	8/20/2014	5	7972	25.66	10.21	34.89	29.25	0.16	GRP/STK		M/N	479.00
AURORA ENERGY LLC	8/21/2014	5	7947	25.16	10.86	35.53	28.45	0.16	GRP/STK		M/N	472.20
AURORA ENERGY LLC	8/25/2014	6	7585	26.17	11.19	35.79	26.86	0.14	GRP/STK		M/N	575.15
AURORA ENERGY LLC	8/27/2014	5	7844	26.46	9.73	35.49	28.33	0.15	GRP/STK		M/N	459.95
AURORA ENERGY LLC	8/28/2014	5	7573	27.55	9.51	35.82	27.13	0.13	TBR	C1	6	453.20
AURORA ENERGY LLC	9/2/2014	5	7853	25.68	10.15	35.75	28.43	0.16	GRP/STK		M/N	444.10
AURORA ENERGY LLC	9/3/2014	7	7595	27.30	9.44	35.06	28.21	0.23	Bdl	E	4	599.15
AURORA ENERGY LLC	9/5/2014	9	7114	24.06	18.70	32.48	24.76	0.24	GRP/STK		M/N	804.25

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	9/5/2014	3	7828	23.73	14.19	34.29	27.79	0.22	GRP/STK		M/N	268.65
AURORA ENERGY LLC	9/5/2014	6	7651	23.59	15.37	33.86	27.19	0.23	GRP/STK		M/N	539.60
AURORA ENERGY LLC	9/8/2014	6	7455	27.39	10.16	36.70	25.75	0.13	Bdl	E	4	535.55
AURORA ENERGY LLC	9/10/2014	12	7336	28.02	10.03	35.87	26.09	0.13	T II	LST	6	1,100.05
AURORA ENERGY LLC	9/11/2014	10	7155	27.65	12.33	34.95	25.08	0.13	T II	LST	6	941.35
AURORA ENERGY LLC	9/15/2014	5	7517	27.42	9.62	35.72	27.25	0.17	Bdl	E	4	464.40
AURORA ENERGY LLC	9/17/2014	7	7531	27.52	9.06	36.59	26.84	0.13	T II	LST	6	652.45
AURORA ENERGY LLC	9/18/2014	6	7493	27.99	8.91	35.72	27.39	0.19	T II	LST	6	539.45
AURORA ENERGY LLC	9/22/2014	5	7793	28.38	6.50	35.62	29.51	0.14	Bdl	E	4	481.40
AURORA ENERGY LLC	9/24/2014	9	7206	26.90	12.00	35.04	26.07	0.13	T II	LST	6	864.35
AURORA ENERGY LLC	9/25/2014	10	7528	28.00	8.47	36.92	26.61	0.12	TII	LST	6	971.75
AURORA ENERGY LLC	9/27/2014	11	7739	28.34	6.81	36.34	28.51	0.18	Bdl	E	4	1,007.10
AURORA ENERGY LLC	9/29/2014	11	7739	28.09	6.87	35.86	29.18	0.19	Bdl	F	4	1,034.60
AURORA ENERGY LLC	9/30/2014	11	7749	28.54	6.60	35.47	29.41	0.16	Bdl	F	4	984.35
AURORA ENERGY LLC	10/1/2014	26	7815	28.29	6.55	35.84	29.32	0.16	Bdl	F	4	2,485.80
AURORA ENERGY LLC	10/6/2014	10	7591	28.11	8.20	36.05	27.65	0.16	Bdl/TII	F/LST	4/6	856.70
AURORA ENERGY LLC	10/8/2014	9	7403	27.49	10.14	35.31	27.07	0.16	Bdl/T II	F/LST	4/6	810.80
AURORA ENERGY LLC	10/8/2014	11	7499	28.23	8.70	36.11	26.96	0.12	T II	LST	6	985.90
AURORA ENERGY LLC	10/9/2014	12	7495	28.17	8.40	36.91	26.52	0.12	T II	LST	6	1,116.25
AURORA ENERGY LLC	10/11/2014	13	7566	28.43	7.85	38.08	25.65	0.12	T II	LST	6	1,133.10
AURORA ENERGY LLC	10/13/2014	7	7405	27.91	9.44	36.23	26.43	0.13	T II	LST	6	676.50
AURORA ENERGY LLC	10/15/2014	11	7971	26.15	9.33	35.38	29.13	0.15	GRP/STK		M/N	997.30
AURORA ENERGY LLC	10/16/2014	16	8040	25.93	8.50	36.45	29.13	0.16	GRP/STK		M/N	1,476.75
AURORA ENERGY LLC	10/20/2014	9	7629	27.68	8.84	36.03	27.45	0.14	T II	LST	6	864.20
AURORA ENERGY LLC	10/21/2014	12	7874	27.45	7.56	35.30	29.69	0.13	Bdl	D	3	1,113.15
AURORA ENERGY LLC	10/22/2014	15	7932	27.59	6.48	35.31	30.62	0.12	Bdl	E	3	1,424.60
AURORA ENERGY LLC	10/23/2014	14	7880	27.56	6.24	36.02	30.19	0.10	Bdl	E	3	1,343.80
AURORA ENERGY LLC	10/24/2014	9	7169	30.71	6.85	34.67	27.79	0.12	Jumbo			783.45
AURORA ENERGY LLC	10/27/2014	12	7748	28.04	7.14	35.35	29.47	0.13	Bdl/STK	D	3/N	1,187.15
AURORA ENERGY LLC	10/28/2014	10	7616	28.45	7.79	35.64	28.13	0.12	Bdl/T II	D/LST	3/6	922.05
AURORA ENERGY LLC	10/29/2014	10	7494	28.14	8.94	35.97	26.95	0.13	T II	LST	6	939.80
AURORA ENERGY LLC	10/30/2014	11	[illegible]	[illegible]	[illegible]	[illegible]	26.15	0.12	TII	LST	6	1,074.40

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	10/31/2014	10	7754	28.43	7.39	36.13	28.06	0.13	TII/Bdl	LST/D	6/3	943.50
AURORA ENERGY LLC	11/3/2014	6	7675	29.16	6.72	34.86	29.26	0.12	Bdl/JD	D	3/4	566.40
AURORA ENERGY LLC	11/4/2014	13	7741	28.44	6.73	35.24	29.59	0.11	Bdl/JD	D	3/4	1,279.15
AURORA ENERGY LLC	11/5/2014	12	7651	28.22	7.68	35.38	28.73	0.12	Bdl/JD	D	3/4	1,176.25
AURORA ENERGY LLC	11/6/2014	9	7622	28.67	7.42	34.84	29.07	0.12	Bdl/JD	D	3/4	848.35
AURORA ENERGY LLC	11/7/2014	12	7769	28.00	7.20	35.32	29.48	0.11	Bdl/JD	D	3/4	1,064.60
AURORA ENERGY LLC	11/10/2014	7	7769	28.21	6.77	35.31	29.71	0.10	Bdl/JD	D	3/4	650.70
AURORA ENERGY LLC	11/11/2014	12	7739	28.65	6.64	35.20	29.52	0.11	Bdl/JD	D	3/4	1,141.50
AURORA ENERGY LLC	11/12/2014	12	7644	29.46	6.67	34.68	29.19	0.12	Bdl/JD	D	3/4	1,120.25
AURORA ENERGY LLC	11/13/2014	9	7613	29.14	6.79	35.81	28.27	0.11	Bdl/JD	D	3/4	840.50
AURORA ENERGY LLC	11/14/2014	7	7805	27.58	7.75	36.16	28.52	0.14	Bdl/JD	D	3/4	638.10
AURORA ENERGY LLC	11/17/2014	6	7749	26.36	10.84	34.65	28.16	0.19	GRP/STK		M/N	604.55
AURORA ENERGY LLC	11/18/2014	31	7295	26.35	14.74	33.00	25.91	0.17	GRP/STK		M/N	3,113.25
AURORA ENERGY LLC	11/19/2014	12	7822	25.92	11.05	34.90	28.14	0.17	GRP/Bdl	D	M/3	1,161.75
AURORA ENERGY LLC	11/21/2014	4	7765	27.96	9.54	34.70	27.80	0.14	GRP/JD		M/4	355.30
AURORA ENERGY LLC	11/24/2014	9	7821	29.00	5.59	36.00	29.41	0.11	Bdl/JD	F	3/4	792.50
AURORA ENERGY LLC	11/25/2014	12	7837	28.38	5.94	35.63	30.05	0.10	Bdl/JD	F	3/4	1,101.60
AURORA ENERGY LLC	11/26/2014	13	7636	29.62	6.57	35.03	28.79	0.09	Bdl/JD	D	3/4	1,157.55
AURORA ENERGY LLC	11/28/2014	9	7798	28.82	6.04	35.55	29.58	0.09	Bdl/JD	F	3/4	775.45
AURORA ENERGY LLC	12/1/2014	8	7814	28.53	6.40	35.39	29.68	0.10	Bdl/STK	F	3/N	742.55
AURORA ENERGY LLC	12/2/2014	11	7843	27.99	6.73	35.16	30.13	0.11	Bdl/STK	F	3/N	1,039.75
AURORA ENERGY LLC	12/3/2014	10	7718	28.26	7.17	35.07	29.51	0.10	Bdl/STK	F	3/N	862.65
AURORA ENERGY LLC	12/4/2014	8	7659	27.93	7.94	35.42	28.71	0.10	Bdl/STK	F	3/N	753.20
AURORA ENERGY LLC	12/5/2014	13	7660	27.86	8.23	35.41	28.51	0.12	Bdl/STK	F	3/N	1,222.65
AURORA ENERGY LLC	12/8/2014	11	7399	26.38	12.62	34.16	26.85	0.31	Bdl/STK	G	4/N	1,068.05
AURORA ENERGY LLC	12/9/2014	10	7758	27.16	8.46	35.76	28.61	0.25	Bdl/STK	G	4/N	933.35
AURORA ENERGY LLC	12/10/2014	8	7671	27.12	8.79	35.30	28.79	0.23	Bdl/STK	G	4/N	730.55
AURORA ENERGY LLC	12/11/2014	9	7762	27.40	8.01	35.48	29.12	0.21	Bdl/Bdl	G/F	4/3	846.70
AURORA ENERGY LLC	12/12/2014	14	7657	27.61	8.26	35.28	28.85	0.15	Bdl/STK	F	3/N	1,285.70
AURORA ENERGY LLC	12/15/2014	12	7491	29.18	8.10	35.28	27.44	0.15	Bdl/JD	G	4/4	1,100.15
AURORA ENERGY LLC	12/16/2014	18	7630	28.23	8.32	35.71	27.74	0.19	Bdl/JD	G	4/4	1,705.05
AURORA ENERGY LLC	12/17/2014	8	[illegible]	[illegible]	[illegible]	[illegible]	28.40	0.16	Bdl/JD	G	4/4	770.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	12/18/2014	20	7528	31.48	6.44	34.37	27.71	0.13	JD		4	1,850.00
AURORA ENERGY LLC	12/19/2014	4	7626	28.89	7.57	35.42	28.12	0.15	Bdl/JD	G	4/4	372.05
AURORA ENERGY LLC	12/22/2014	10	7561	28.72	8.34	35.26	27.69	0.18	Bdl/JD	G	4/4	981.45
AURORA ENERGY LLC	12/23/2014	17	7598	28.65	8.05	35.35	27.95	0.18	Bdl/JD	G	4/4	1,535.65
AURORA ENERGY LLC	12/24/2014	12	7563	28.54	8.75	35.22	27.50	0.19	Bdl/JD	G	4/4	1,037.65
AURORA ENERGY LLC	12/26/2014	6	7418	26.62	12.03	34.98	26.37	0.28	Bdl/JD	G	4/4	550.45
AURORA ENERGY LLC	12/29/2014	8	7385	27.89	10.46	34.77	26.89	0.25	Bdl/JD	G	4/4	778.85
AURORA ENERGY LLC	12/30/2014	12	7568	29.02	8.07	34.65	28.26	0.21	Bdl/JD	G	4/4	1,145.15
AURORA ENERGY LLC	12/31/2014	10	7643	29.27	7.21	35.29	28.24	0.18	Bdl/JD	G	4/4	880.85

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103979.45	7617.00	27.86	8.67	35.66	27.82	0.14

This analysis is representative of the coal shipped using sulfur
ASTM D4239-12

Colleen Thompson
1-5-15

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2015	10	7542	28.10	8.78	35.14	27.98	0.22	Bdl/JD	G	4/4	913.35
AURORA ENERGY LLC	1/5/2015	8	7586	29.30	7.87	34.51	28.33	0.21	Bdl/JD	G	4/4	761.95
AURORA ENERGY LLC	1/6/2015	15	7593	29.68	7.16	34.84	28.32	0.21	Bdl/JD	G	4/4	1,331.30
AURORA ENERGY LLC	1/7/2015	10	7609	29.88	6.82	34.57	28.74	0.19	Bdl/JD	G	4/4	913.10
AURORA ENERGY LLC	1/8/2015	13	7572	27.19	9.58	35.09	28.15	0.24	Bdl/JD	G	4/4	1,217.90
AURORA ENERGY LLC	1/9/2015	13	7658	28.66	7.66	35.64	28.04	0.20	Bdl/JD	G	4/4	1,270.65
AURORA ENERGY LLC	1/12/2015	8	7612	27.19	9.36	35.22	28.24	0.22	Bdl/ T II	G/LST	4/6	735.75
AURORA ENERGY LLC	1/13/2015	13	7605	27.86	8.81	35.00	28.33	0.21	Bdl/T II	G/LST	4/6	1,249.40
AURORA ENERGY LLC	1/14/2015	30	7355	26.04	12.63	34.27	27.07	0.31	Bdl/STK	G	4/N	2,906.30
AURORA ENERGY LLC	1/14/2015	10	7413	26.77	11.28	34.53	27.42	0.30	Bdl/STK	G	4/N	985.30
AURORA ENERGY LLC	1/19/2015	8	7722	27.69	7.86	35.65	28.80	0.15	Bdl/STK	G	4/N	710.60
AURORA ENERGY LLC	1/20/2015	13	7615	28.20	7.93	36.17	27.71	0.15	TII/STK	LST	6/N	1,225.25
AURORA ENERGY LLC	1/21/2015	10	7493	27.67	9.57	36.02	26.75	0.14	T II	LST	6	954.30
AURORA ENERGY LLC	1/22/2015	8	7625	27.33	8.98	35.40	28.28	0.22	Bdl/STK	G	4/N	778.30
AURORA ENERGY LLC	1/26/2015	9	7635	27.97	7.73	35.95	28.36	0.15	Bdl/T II	F/LST	3/6	835.50
AURORA ENERGY LLC	1/27/2015	7	7516	28.18	8.81	36.32	26.69	0.14	T II	LST	6	645.20
AURORA ENERGY LLC	1/28/2015	5	7469	28.31	9.15	36.13	26.41	0.15	T II	LST	6	448.45
AURORA ENERGY LLC	1/29/2015	6	7515	28.38	8.44	36.63	26.56	0.13	TII	LST	6	554.05
AURORA ENERGY LLC	1/29/2015	5	7607	28.03	8.04	36.88	27.05	0.13	TII	LST	6	424.60
AURORA ENERGY LLC	1/30/2015	14	7541	28.33	8.44	37.02	26.22	0.13	TII	LST	6	1,209.20
AURORA ENERGY LLC	2/2/2015	9	7551	28.26	8.55	36.52	26.67	0.14	TII	LST	6	834.90
AURORA ENERGY LLC	2/3/2015	31	7078	28.44	12.14	34.70	24.73	0.15	T II	LST	6	2,869.90
AURORA ENERGY LLC	2/3/2015	11	7036	27.65	12.98	35.06	24.32	0.14	T II	LST	6	969.85
AURORA ENERGY LLC	2/4/2015	12	7065	28.03	12.16	34.62	25.20	0.15	T II	LST	6	1,138.45
AURORA ENERGY LLC	2/9/2015	9	7620	27.91	7.79	35.30	29.02	0.13	Bdl/JD	F	3/4	742.75
AURORA ENERGY LLC	2/10/2015	14	7917	27.82	5.80	35.90	30.48	0.12	Bdl/JD	F	3/4	1,277.15
AURORA ENERGY LLC	2/11/2015	8	7702	29.02	6.64	35.33	29.02	0.12	Bdl/JD	F	3/4	680.85
AURORA ENERGY LLC	2/12/2015	6	7618	28.59	7.59	35.98	27.84	0.12	Bdl/JD	F	3/4	525.70
AURORA ENERGY LLC	2/13/2015	8	7614	29.50	7.11	35.67	27.72	0.12	Bdl/JD	F	3/4	674.15
AURORA ENERGY LLC	2/16/2015	8	7681	29.80	6.49	35.97	27.74	0.11	T II/JD	LST	6/4	716.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	2/17/2015	10	7645	30.40	6.24	35.65	27.71	0.12	JD		4	871.10
AURORA ENERGY LLC	2/18/2015	9	7411	30.93	6.97	34.84	27.27	0.13	T II/JD	LST	6/4	775.50
AURORA ENERGY LLC	2/19/2015	10	7474	29.85	7.43	36.13	26.59	0.12	JD/T II	LST	4/6	893.10
AURORA ENERGY LLC	2/20/2015	12	7556	30.19	6.65	36.82	26.35	0.12	T II/JD	LST	6/4	1,087.75
AURORA ENERGY LLC	2/23/2015	8	7490	30.65	6.82	35.48	27.06	0.13	T II/JD	LST	6/4	756.30
AURORA ENERGY LLC	2/24/2015	11	7576	29.59	7.24	35.95	27.22	0.14	JD/TII	LST	4/6	975.50
AURORA ENERGY LLC	2/25/2015	11	7551	29.41	7.42	35.92	27.25	0.13	T II/JD	LST	6/4	1,033.85
AURORA ENERGY LLC	2/26/2015	11	7582	29.74	6.75	36.28	27.23	0.12	T II/JD	LST	6/4	1,003.80
AURORA ENERGY LLC	2/27/2015	11	7588	29.97	6.61	36.05	27.37	0.12	TII/JD	LST	6/4	1,039.00
AURORA ENERGY LLC	3/2/2015	8	7571	29.92	6.43	36.02	27.64	0.12	TII/JD	LST	6/4	730.55
AURORA ENERGY LLC	3/3/2015	10	7698	29.84	5.91	36.58	27.67	0.11	TII/JD	LST	6/4	910.05
AURORA ENERGY LLC	3/4/2015	4	7547	30.62	6.34	35.70	27.34	0.11	TII/JD	LST	6/4	356.15
AURORA ENERGY LLC	3/5/2015	10	7705	29.51	6.01	36.35	28.13	0.11	TII/JD	LST	6/4	927.65
AURORA ENERGY LLC	3/6/2015	11	7662	30.66	5.49	36.26	27.60	0.11	TII/JD	LST	6/4	1,032.00
AURORA ENERGY LLC	3/10/2015	6	7505	30.34	6.76	36.30	26.60	0.11	TII/JD	LST	6/4	549.70
AURORA ENERGY LLC	3/11/2015	26	7109	31.44	7.90	34.89	25.76	0.10	TII/JD	LST	6/4	2,416.95
AURORA ENERGY LLC	3/12/2015	7	7483	29.94	7.34	35.71	27.02	0.11	TII/JD	LST	6/4	620.10
AURORA ENERGY LLC	3/16/2015	4	7525	29.76	7.33	35.86	27.05	0.14	TII/JD	LST	6/4	370.10
AURORA ENERGY LLC	3/17/2015	5	7468	30.08	7.36	35.59	26.98	0.11	TII/JD	LST	6/4	463.30
AURORA ENERGY LLC	3/18/2015	12	7545	30.21	6.84	35.43	27.53	0.12	TII/JD	LST	6/4	1,088.95
AURORA ENERGY LLC	3/19/2015	12	7549	29.60	7.58	35.96	26.86	0.14	TII/JD	LST	6/4	1,105.10
AURORA ENERGY LLC	3/20/2015	7	7620	29.93	7.00	36.02	27.06	0.12	TII/JD	LST	6/4	680.20
AURORA ENERGY LLC	3/23/2015	5	7555	29.89	6.88	35.98	27.26	0.12	TII/JD	LST	6/4	453.55
AURORA ENERGY LLC	4/2/2015	7	7727	30.71	5.38	35.08	28.84	0.12	JD		4	641.55
AURORA ENERGY LLC	4/6/2015	10	7763	31.03	4.67	35.18	29.13	0.11	JD		4	908.40
AURORA ENERGY LLC	4/7/2015	12	7826	30.95	4.55	35.57	28.93	0.11	JD		4	1,081.35
AURORA ENERGY LLC	4/8/2015	11	7669	31.37	5.35	34.58	28.71	0.11	JD		4	1,022.50
AURORA ENERGY LLC	4/9/2015	13	7561	31.87	5.36	34.64	28.14	0.12	JD		4	1,161.20
AURORA ENERGY LLC	4/10/2015	7	7759	30.74	5.03	35.70	28.54	0.11	JD		4	660.95
AURORA ENERGY LLC	4/13/2015	9	7711	31.37	4.82	34.74	29.07	0.11	JD		4	798.25
AURORA ENERGY LLC	4/14/2015	12	7710	31.37	4.77	35.27	28.60	0.11	JD		4	1,105.30
AURORA ENERGY LLC	4/20/2015	9	7625	30.63	5.99	34.56	28.82	0.09	JD		4	836.95

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	4/21/2015	11	7544	30.03	7.59	33.80	28.58	0.11	JD		4	989.35
AURORA ENERGY LLC	4/22/2015	8	7626	29.64	7.23	34.32	28.81	0.14	Bdl/JD	G	4/4	768.10
AURORA ENERGY LLC	4/27/2015	8	7881	29.30	5.28	35.34	30.09	0.11	JD/Bdl	G	4/3	745.75
AURORA ENERGY LLC	4/28/2015	10	7853	29.01	5.21	35.72	30.06	0.11	Bdl/JD	G	3/4	903.75
AURORA ENERGY LLC	4/29/2015	10	7620	31.74	4.50	35.15	28.61	0.10	JD		4	904.95
AURORA ENERGY LLC	4/30/2015	12	7648	28.84	7.36	34.53	29.28	0.11	Bdl/JD	G	3/4	1,151.95
AURORA ENERGY LLC	5/1/2015	8	7453	31.00	6.78	34.50	27.73	0.10	JD		4	733.95
AURORA ENERGY LLC	5/4/2015	10	7424	31.57	6.35	34.12	27.97	0.12	JD		4	891.35
AURORA ENERGY LLC	5/5/2015	8	7414	31.82	6.59	33.68	27.91	0.11	JD		4	747.95
AURORA ENERGY LLC	5/6/2015	11	7610	30.24	6.28	34.87	28.62	0.11	Bdl/JD	G	3/4	980.55
AURORA ENERGY LLC	5/7/2015	9	7511	31.23	6.16	34.56	28.05	0.11	JD		4	873.00
AURORA ENERGY LLC	5/8/2015	8	7743	29.92	5.94	35.21	28.94	0.12	JD		4	704.65
AURORA ENERGY LLC	5/12/2015	15	7685	29.76	6.46	35.56	28.22	0.11	JD		4	1,411.50
AURORA ENERGY LLC	5/13/2015	15	7530	29.73	7.50	35.02	27.76	0.12	Bdl/JD	G	3/4	1,361.45
AURORA ENERGY LLC	5/14/2015	1	7565	30.33	6.72	34.88	28.08	0.11	JD		4	99.55
AURORA ENERGY LLC	5/18/2015	13	7707	29.87	6.38	35.17	28.58	0.11	JD		4	1,253.45
AURORA ENERGY LLC	5/19/2015	8	7694	30.15	6.19	34.79	28.88	0.11	JD		4	704.35
AURORA ENERGY LLC	5/20/2015	12	7626	30.39	6.33	34.90	28.38	0.12	JD		4	1,155.60
AURORA ENERGY LLC	5/21/2015	12	7494	31.30	6.38	34.44	27.89	0.11	JD		4	1,157.45
AURORA ENERGY LLC	5/23/2015	18	7765	29.51	6.18	35.46	28.85	0.11	JD		4	1,660.70
AURORA ENERGY LLC	5/26/2015	8	7580	29.83	7.16	34.99	28.03	0.12	JD		4	732.30
AURORA ENERGY LLC	5/27/2015	14	7685	28.61	7.56	35.32	28.52	0.12	JD		4	1,376.90
AURORA ENERGY LLC	5/28/2015	14	7626	29.63	6.99	34.90	28.48	0.12	JD		4	1,353.00
AURORA ENERGY LLC	5/29/2015	6	7579	30.41	6.82	34.66	28.11	0.13	JD		4	565.25
AURORA ENERGY LLC	6/1/2015	9	7636	30.25	6.18	35.13	28.44	0.12	JD		4	857.75
AURORA ENERGY LLC	6/2/2015	8	7728	31.26	4.72	35.04	28.98	0.12	JD		4	727.00
AURORA ENERGY LLC	6/3/2015	12	7547	31.16	6.51	33.90	28.44	0.12	JD		4	1,199.65
AURORA ENERGY LLC	6/4/2015	13	7792	30.16	5.50	34.95	29.39	0.12	JD		4	1,262.20
AURORA ENERGY LLC	6/5/2015	13	7703	30.94	5.14	35.45	28.48	0.11	JD		4	1,158.10
AURORA ENERGY LLC	6/8/2015	10	7842	30.61	4.60	35.17	29.63	0.11	JD		4	944.15
AURORA ENERGY LLC	6/9/2015	8	7726	30.82	5.57	34.59	29.03	0.12	JD		4	772.90
AURORA ENERGY LLC	6/10/2015	9	7794	30.29	4.94	35.61	29.16	0.12	JD		4	865.10

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	6/11/2015	2	7952	29.43	5.92	34.72	29.93	0.12	GRP/STK		M/N	194.00
AURORA ENERGY LLC	6/12/2015	11	7855	28.23	7.74	34.69	29.34	0.14	GRP/STK		M/N	1,098.10
AURORA ENERGY LLC	6/15/2015	10	7900	26.99	8.73	35.33	28.95	0.14	GRP/STK		M/N	996.05
AURORA ENERGY LLC	6/16/2015	6	7887	25.37	10.64	35.26	28.73	0.15	GRP/STK		M/N	588.95
AURORA ENERGY LLC	6/17/2015	29	7528	24.32	14.26	34.44	26.99	0.15	GRP/STK		M/N	2,832.55
AURORA ENERGY LLC	6/17/2015	9	7518	24.53	13.61	35.06	26.81	0.15	GRP/STK		M/N	868.65
AURORA ENERGY LLC	6/22/2015	10	7649	28.27	8.58	35.13	28.03	0.13	JD		4	976.50
AURORA ENERGY LLC	6/23/2015	12	7581	28.39	8.07	34.39	29.15	0.13	Bdl		3	1,185.10
AURORA ENERGY LLC	6/24/2015	9	7885	27.12	7.70	35.35	29.83	0.13	Bdl/STK		6/N	861.60
AURORA ENERGY LLC	6/25/2015	8	7813	27.83	6.96	35.60	29.62	0.11	Bdl/STK	I	3/N	748.55
AURORA ENERGY LLC	6/26/2015	10	8048	26.19	8.73	35.21	29.87	0.15	GRP/STK		M/N	959.85
AURORA ENERGY LLC	6/29/2015	14	8027	26.68	8.75	34.64	29.93	0.15	GRP/STK		M/N	1,393.95
AURORA ENERGY LLC	6/30/2015	14	7934	27.67	7.69	35.54	29.11	0.14	JD		4	1,330.30

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103904.80	7599.00	29.16	7.65	35.23	27.96	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-1-15

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/2/2015	5	7689	29.31	7.19	35.30	28.21	0.13	Bdl/GRP	I	3/M	497.30
AURORA ENERGY LLC	7/6/2015	14	7636	28.59	7.92	35.01	28.49	0.15	Bld	I	4	1,372.10
AURORA ENERGY LLC	7/7/2015	14	7874	26.58	7.76	36.94	28.71	0.21	Bdl	I	4	1,382.00
AURORA ENERGY LLC	7/8/2015	3	7865	26.43	7.83	36.21	29.54	0.21	BLD	I	4	316.65
AURORA ENERGY LLC	7/9/2015	8	7770	26.23	8.84	36.65	28.29	0.23	Bdl	I	4	785.95
AURORA ENERGY LLC	7/10/2015	5	7921	25.95	8.00	36.75	29.31	0.19	Bdl	I	4	508.65
AURORA ENERGY LLC	7/13/2015	10	7931	25.76	7.97	36.81	29.47	0.18	Bdl	I	4	979.25
AURORA ENERGY LLC	7/14/2015	10	7750	26.64	8.53	36.28	28.56	0.21	Bdl	I	4	954.80
AURORA ENERGY LLC	7/15/2015	10	7867	26.76	7.54	36.58	29.13	0.21	Bdl	I	4	982.35
AURORA ENERGY LLC	7/16/2015	15	7868	26.59	7.56	36.90	28.95	0.21	Bdl	I	4	1,462.70
AURORA ENERGY LLC	7/17/2015	8	7832	26.21	7.83	37.22	28.75	0.22	Bdl	I	4	765.40
AURORA ENERGY LLC	7/20/2015	8	7860	27.03	7.13	36.27	29.58	0.19	Bdl	I	4	766.65
AURORA ENERGY LLC	7/21/2015	9	7694	27.61	7.96	35.51	28.93	0.20	Bdl/STK	I	4/N	908.35
AURORA ENERGY LLC	7/22/2015	9	7657	29.32	6.95	35.01	28.72	0.15	JD		4	877.65
AURORA ENERGY LLC	7/23/2015	9	7438	30.33	7.55	34.18	27.95	0.12	JD		4	859.90
AURORA ENERGY LLC	7/24/2015	8	7636	29.50	6.86	35.30	28.35	0.11	JD		4	772.45
AURORA ENERGY LLC	7/27/2015	9	7432	31.12	7.58	33.61	27.70	0.13	JD		4	899.50
AURORA ENERGY LLC	7/28/2015	11	7523	30.83	6.76	34.27	28.14	0.12	JD		4	1,073.20
AURORA ENERGY LLC	7/30/2015	7	7425	30.34	7.77	34.10	27.79	0.14	JD		4	693.90
AURORA ENERGY LLC	7/31/2015	8	7734	27.22	7.93	35.90	28.96	0.22	Bdl/Bdl	I/I	3/4	724.30
AURORA ENERGY LLC	8/3/2015	9	7654	28.48	7.69	35.42	28.41	0.16	JD		4	867.75
AURORA ENERGY LLC	8/4/2015	10	7670	29.51	6.73	35.20	28.57	0.14	JD		4	937.50
AURORA ENERGY LLC	8/5/2015	12	7566	30.37	6.67	35.07	27.90	0.13	JD		4	999.75
AURORA ENERGY LLC	8/6/2015	11	7279	30.35	9.11	34.22	26.33	0.14	JD		4	1,037.80
AURORA ENERGY LLC	8/7/2015	11	7368	30.17	8.21	34.20	27.42	0.15	Bdl/JD	I	4/4	1,056.30
AURORA ENERGY LLC	8/10/2015	18	7660	29.39	6.76	35.20	28.65	0.15	JD/Bdl	/I	4/4	1,653.75
AURORA ENERGY LLC	8/12/2015	15	7359	31.58	7.10	33.94	27.40	0.14	JD		4	1,416.85
AURORA ENERGY LLC	8/13/2015	18	7510	30.41	6.79	34.63	28.16	0.17	Bdl/JD	I	4/4	1,775.95
AURORA ENERGY LLC	8/14/2015	15	7733	27.83	7.35	36.00	28.82	0.14	Bdl	I	4	1,397.60
AURORA ENERGY LLC	8/17/2015	10	7663	29.07	7.20	35.01	28.73	0.13	JD		4	943.65

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	8/18/2015	13	7658	28.80	7.07	35.38	28.76	0.16	JD		4	1,265.45
AURORA ENERGY LLC	8/20/2015	15	7311	31.47	7.37	33.83	27.33	0.12	Bdl/JD	I/	3/4	1,386.75
AURORA ENERGY LLC	8/22/2015	18	7564	31.72	6.35	34.30	27.63	0.10	JD		4	1,546.75
AURORA ENERGY LLC	8/26/2015	15	7740	28.52	8.85	34.07	28.56	0.17	JD/GRP		4/M	1,471.40
AURORA ENERGY LLC	8/28/2015	3	7642	28.09	8.57	35.40	27.94	0.15	GPR/Bdl		M/6	261.50
AURORA ENERGY LLC	8/31/2015	8	7628	27.35	8.96	36.33	27.37	0.14	Bdl		6	720.95
AURORA ENERGY LLC	9/1/2015	17	7681	27.34	8.39	36.84	27.43	0.13	Bdl		6	1,651.15
AURORA ENERGY LLC	9/2/2015	19	7563	27.07	9.34	36.51	27.09	0.14	Bdl		6	1,898.00
AURORA ENERGY LLC	9/3/2015	27	7665	27.56	8.27	35.87	28.31	0.13	Bdl		6	2,698.95
AURORA ENERGY LLC	9/8/2015	17	7806	27.29	7.46	35.64	29.61	0.13	Bdl/STK	I/	3/N	1,594.85
AURORA ENERGY LLC	9/10/2015	20	7891	26.52	7.77	35.76	29.97	0.14	Bdl/GRP	I/	3/M	1,863.50
AURORA ENERGY LLC	9/11/2015	21	7710	26.65	9.21	35.53	28.61	0.14	Bdl/GRP	I	3/M	1,974.90
AURORA ENERGY LLC	9/15/2015	18	7420	26.03	13.40	33.43	27.10	0.16	Bdl/GRP	I	3/M	1,735.35
AURORA ENERGY LLC	9/16/2015	17	7697	26.35	10.77	36.32	26.56	0.16	GRP/Bdl		M/6	1,681.25
AURORA ENERGY LLC	9/17/2015	17	7519	26.86	10.99	35.61	26.55	0.16	Bdl/GRP		6/M	1,555.60
AURORA ENERGY LLC	9/22/2015	19	7186	27.11	12.93	34.08	25.88	0.17	Bdl/GRP		6/M	1,877.05
AURORA ENERGY LLC	9/23/2015	18	7544	27.46	9.76	34.45	28.34	0.15	Bdl	I	3	1,812.45
AURORA ENERGY LLC	9/24/2015	6	7573	26.47	10.49	34.19	28.85	0.14	Bdl	I	3	604.35
AURORA ENERGY LLC	9/29/2015	6	7141	28.88	11.36	33.89	25.87	0.15	Bdl/GRP	I	3/M	603.55
AURORA ENERGY LLC	9/30/2015	5	7514	28.44	8.69	34.21	28.66	0.13	Bdl/Bdl	I	3/6	490.85
AURORA ENERGY LLC	10/1/2015	10	7360	29.29	9.35	33.72	27.64	0.14	Bdl/Bdl	I	3/6	949.70
AURORA ENERGY LLC	10/6/2015	17	7434	28.25	9.47	34.75	27.54	0.14	Bdl		6	1,697.60
AURORA ENERGY LLC	10/7/2015	16	7427	28.14	9.75	33.75	28.48	0.13	Bdl/STK	I	3/N	1,590.90
AURORA ENERGY LLC	10/8/2015	16	7766	28.02	6.97	35.04	29.97	0.14	Bdl/STK	I	3/N	1,550.35
AURORA ENERGY LLC	10/12/2015	12	7509	28.74	8.47	34.02	28.77	0.11	Bdl/JD	I	3/4	1,188.55
AURORA ENERGY LLC	10/13/2015	14	7448	29.46	8.57	34.10	27.88	0.11	Bdl/JD	I	3/4	1,378.00
AURORA ENERGY LLC	10/14/2015	15	7329	31.93	7.28	33.16	27.63	0.11	Bdl/JD	I	3/4	1,487.05
AURORA ENERGY LLC	10/15/2015	5	7435	31.66	6.81	34.31	27.23	0.11	JD		4	472.55
AURORA ENERGY LLC	10/16/2015	6	7723	31.20	5.10	35.54	28.17	0.11	JD		4	564.80
AURORA ENERGY LLC	10/20/2015	15	7561	31.93	5.92	34.77	27.38	0.11	JD		4	1,442.25
AURORA ENERGY LLC	10/21/2015	14	7609	31.67	5.47	34.54	28.32	0.11	JD		4	1,346.70
AURORA ENERGY LLC	10/22/2015	13	7492	32.01	6.01	34.29	27.70	0.11	JD		4	1,264.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	10/23/2015	15	7347	32.39	6.71	33.49	27.42	0.12	JD		4	1,492.50
AURORA ENERGY LLC	10/27/2015	9	7404	30.15	8.49	34.36	27.00	0.18	Bdl	J	4	910.80
AURORA ENERGY LLC	10/28/2015	11	7586	30.32	6.73	35.02	27.93	0.14	Bld/JD	J/	4/4	1,018.90
AURORA ENERGY LLC	10/29/2015	9	7861	26.44	7.92	36.05	29.59	0.19	Bdl	J	4	922.55
AURORA ENERGY LLC	10/30/2015	11	7948	26.92	7.00	36.90	29.19	0.17	Bdl	J	4	1,070.45
AURORA ENERGY LLC	11/3/2015	10	7438	27.87	10.34	34.56	27.24	0.28	Bdl/JD	J/	4/4	994.40
AURORA ENERGY LLC	11/4/2015	16	7495	29.67	8.21	34.18	27.95	0.20	Bdl	J	4	1,577.40
AURORA ENERGY LLC	11/5/2015	11	7320	29.67	9.27	33.61	27.46	0.22	Bdl	J	4	1,052.25
AURORA ENERGY LLC	11/6/2015	12	7629	27.60	8.75	35.23	28.42	0.25	Bdl/JD	J/	4/4	1,175.00
AURORA ENERGY LLC	11/10/2015	12	7640	28.50	7.97	35.25	28.29	0.19	Bdl	J	4	1,130.35
AURORA ENERGY LLC	11/11/2015	14	7865	27.22	7.50	35.71	29.58	0.21	Bdl	J	4	1,331.05
AURORA ENERGY LLC	11/12/2015	12	7797	27.25	7.73	35.48	29.54	0.23	Bdl	J	4	1,146.35
AURORA ENERGY LLC	11/13/2015	14	7947	26.11	7.79	36.51	29.60	0.19	Bdl	J	4	1,368.95
AURORA ENERGY LLC	11/17/2015	9	7760	27.53	7.86	35.47	29.14	0.20	Bdl/JD	J/	4/4	848.40
AURORA ENERGY LLC	11/18/2015	11	7705	28.38	7.44	35.64	28.55	0.18	Bdl/JD	J	4/4	1,026.00
AURORA ENERGY LLC	11/19/2015	8	7644	30.78	6.20	34.89	28.13	0.15	Bdl/JD	J	4/4	714.95
AURORA ENERGY LLC	11/20/2015	10	7783	29.27	6.29	35.70	28.73	0.15	JD/Bdl	/J	4/4	863.55
AURORA ENERGY LLC	11/23/2015	11	7793	29.35	6.29	35.57	28.79	0.15	JD		4	1,046.45
AURORA ENERGY LLC	11/24/2015	16	7682	30.62	5.97	34.92	28.49	0.12	JD		4	1,518.80
AURORA ENERGY LLC	11/25/2015	13	7770	29.54	6.19	35.63	28.65	0.14	JD/Bdl	/J	4/4	1,206.80
AURORA ENERGY LLC	11/27/2015	12	7612	28.41	7.98	35.68	27.94	0.19	Bdl/STK	J/	4/N	1,178.80
AURORA ENERGY LLC	12/1/2015	21	7514	29.25	8.35	34.58	27.83	0.20	Bdl/STK	J/	4/N	1,971.15
AURORA ENERGY LLC	12/2/2015	9	7587	30.48	6.72	34.32	28.49	0.16	JD		4	834.10
AURORA ENERGY LLC	12/3/2015	12	7577	32.45	4.74	33.98	28.84	0.10	JD		4	1,097.45
AURORA ENERGY LLC	12/4/2015	10	7503	31.28	6.60	33.78	28.35	0.12	JD		4	915.25
AURORA ENERGY LLC	12/8/2015	13	7594	29.65	7.36	34.53	28.47	0.17	Bdl/JD	J/	4/4	1,204.60
AURORA ENERGY LLC	12/9/2015	13	7627	28.50	8.21	34.71	28.58	0.23	Bdl/JD	J/	4/4	1,254.80
AURORA ENERGY LLC	12/10/2015	12	7651	29.18	7.10	35.18	28.55	0.17	Bdl/JD	J/	4/4	1,090.15
AURORA ENERGY LLC	12/11/2015	10	7159	33.74	6.25	34.17	25.84	0.14	JD		4	935.95
AURORA ENERGY LLC	12/15/2015	14	7591	31.15	5.91	35.16	27.78	0.15	Bdl/JD	J	4/4	1,235.25
AURORA ENERGY LLC	12/16/2015	14	7527	31.73	6.00	35.00	27.27	0.16	Bdl/JD	J	4/4	1,288.80
AURORA ENERGY LLC	12/17/2015	14	7639	29.80	6.85	35.24	28.12	0.16	Bdl/JD	J	4/4	1,258.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	12/18/2015	14	7571	30.68	6.58	34.72	28.03	0.13	Bdl/JD	J	4/4	1,314.95
AURORA ENERGY LLC	12/21/2015	14	7631	30.24	6.30	35.17	28.29	0.15	Bdl/JD	J	4/4	1,318.90
AURORA ENERGY LLC	12/22/2015	14	7549	31.19	5.71	34.71	28.39	0.13	Bdl/JD	J	4/4	1,250.95
AURORA ENERGY LLC	12/23/2015	14	7686	31.43	4.63	35.27	28.68	0.10	Bdl/JD	J	4/4	1,262.70
AURORA ENERGY LLC	12/24/2015	10	7627	31.52	4.92	35.64	27.93	0.11	Bdl/JD	J	4/4	933.25
AURORA ENERGY LLC	12/28/2015	14	7714	30.71	4.93	36.01	28.36	0.11	Bdl/JD	J	4/4	1,246.45
AURORA ENERGY LLC	12/29/2015	16	7780	30.08	5.31	35.97	28.65	0.12	Bdl/JD	J	4/4	1,424.70
AURORA ENERGY LLC	12/30/2015	11	7673	31.40	5.02	35.64	27.95	0.12	Bdl/JD	J	4/4	968.20
AURORA ENERGY LLC	12/31/2015	12	7705	31.63	4.47	35.57	28.34	0.12	Bdl/JD	J	3/4	1,059.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	120758.30	7610.00	29.02	7.69	35.09	28.20	0.15

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 1-7-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/5/2016	12	7673	31.18	4.92	35.22	28.68	0.11	Bdl/JD	J	4/4	1,108.40
AURORA ENERGY LLC	1/6/2016	14	7682	32.31	4.20	34.85	28.65	0.11	JD		4	1,247.50
AURORA ENERGY LLC	1/7/2016	14	7643	32.35	3.60	35.28	28.78	0.09	JD		4	1,202.65
AURORA ENERGY LLC	1/8/2016	12	7757	31.14	4.23	36.17	28.47	0.11	JD		4	1,070.90
AURORA ENERGY LLC	1/12/2016	13	7631	32.21	4.40	35.14	28.22	0.11	Bdl/JD	J	4/4	1,200.75
AURORA ENERGY LLC	1/13/2016	18	7628	32.43	4.12	35.32	28.15	0.09	JD		4	1,613.00
AURORA ENERGY LLC	1/14/2016	14	7958	28.18	4.48	37.67	29.68	0.11	JD		4	1,188.40
AURORA ENERGY LLC	1/15/2016	16	7789	31.38	4.12	36.77	27.74	0.11	JD		4	1,385.20
AURORA ENERGY LLC	1/19/2016	18	7765	31.50	4.26	35.37	28.87	0.10	JD		4	1,604.95
AURORA ENERGY LLC	1/20/2016	16	7842	31.19	4.24	35.66	28.92	0.12	JD		4	1,439.05
AURORA ENERGY LLC	1/21/2016	15	7766	31.45	4.46	35.39	28.71	0.13	JD		4	1,348.85
AURORA ENERGY LLC	1/22/2016	22	7741	31.09	4.62	35.72	28.58	0.11	JD		4	1,962.55
AURORA ENERGY LLC	1/26/2016	14	7416	32.12	6.10	34.25	27.54	0.13	JD		4	1,350.60
AURORA ENERGY LLC	1/27/2016	12	7664	31.19	5.07	35.10	28.65	0.11	Bdl/JD	J	4/4	1,095.55
AURORA ENERGY LLC	1/28/2016	11	7741	31.54	4.52	35.16	28.79	0.10	Bdl/JD	J	4/4	982.50
AURORA ENERGY LLC	1/29/2016	13	7646	31.93	4.34	35.66	28.09	0.10	JD		4	1,140.40
AURORA ENERGY LLC	2/2/2016	12	7569	31.65	5.24	34.87	28.26	0.10	JD/Bdl	/J	4/3	1,088.10
AURORA ENERGY LLC	2/3/2016	13	7695	31.32	4.75	35.02	28.92	0.12	Bdl/JD	J	3/4	1,202.80
AURORA ENERGY LLC	2/4/2016	8	7549	30.72	6.88	34.43	27.98	0.18	Bdl/JD	J	4/4	705.70
AURORA ENERGY LLC	2/5/2016	11	7664	30.92	5.55	35.22	28.31	0.14	JD/Bdl	/J	4/4	998.75
AURORA ENERGY LLC	2/9/2016	14	7572	31.26	6.21	34.69	27.85	0.13	JD		4	1,298.35
AURORA ENERGY LLC	2/10/2016	13	7785	29.54	6.19	35.63	28.65	0.15	Bdl/JD	J	4/4	1,191.45
AURORA ENERGY LLC	2/11/2016	11	7479	31.97	5.48	34.93	27.63	0.14	Bdl/JD	J	4/4	1,023.95
AURORA ENERGY LLC	2/12/2016	15	7576	30.68	5.50	35.74	28.08	0.14	Bdl/JD	J	4/4	1,417.30
AURORA ENERGY LLC	2/16/2016	16	7634	30.60	5.38	36.09	27.93	0.14	JD/Bdl	/J	4/4	1,512.75
AURORA ENERGY LLC	2/17/2016	14	7781	29.69	5.73	35.79	28.79	0.17	Bdl/JD	J	4/4	1,299.10
AURORA ENERGY LLC	2/18/2016	11	7773	30.32	5.11	35.59	28.99	0.14	Bdl/JD	J	4/4	1,016.45
AURORA ENERGY LLC	2/19/2016	16	7808	29.51	5.45	36.18	28.86	0.14	JD/Bdl	/J	4/4	1,465.95
AURORA ENERGY LLC	2/23/2016	21	7926	29.40	4.93	36.36	29.31	0.14	JD		4	1,903.35

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	2/24/2016	16	7799	31.52	4.31	35.32	28.85	0.12	Bdl/JD	J	4/4	1,498.15
AURORA ENERGY LLC	2/25/2016	15	7794	31.50	4.13	35.15	29.22	0.10	JD		4	1,324.05
AURORA ENERGY LLC	3/1/2016	12	7806	30.97	4.49	36.14	28.40	0.12	JD		4	1,126.55
AURORA ENERGY LLC	3/2/2016	16	7805	31.54	4.14	35.52	28.80	0.11	JD		4	1,478.45
AURORA ENERGY LLC	3/3/2016	14	7717	32.25	4.14	35.10	28.52	0.11	JD		4	1,295.50
AURORA ENERGY LLC	3/4/2016	16	7828	31.13	4.14	36.06	28.67	0.11	JD		4	1,430.90
AURORA ENERGY LLC	3/8/2016	13	7701	29.55	6.64	34.82	28.99	0.12	JD/Bdl	/J	4/3	1,224.45
AURORA ENERGY LLC	3/9/2016	13	7732	30.28	5.88	34.95	28.89	0.11	JD/Bdl	/J	4/3	1,231.45
AURORA ENERGY LLC	3/15/2016	12	7823	29.23	5.87	35.65	29.26	0.11	JD/Bdl	/J	4/3	1,121.25
AURORA ENERGY LLC	3/16/2016	13	7871	30.17	4.64	35.79	29.39	0.11	JD		4	1,143.60
AURORA ENERGY LLC	3/17/2016	13	7767	28.41	7.14	35.19	29.27	0.12	Bdl/STK	J/	3/	1,222.65
AURORA ENERGY LLC	3/18/2016	14	7766	27.74	7.62	35.37	29.27	0.12	Bdl/STK	J/	3/	1,287.65
AURORA ENERGY LLC	3/22/2016	14	7719	29.44	6.41	35.32	28.84	0.11	Bdl/JD	J/	3/4	1,317.00
AURORA ENERGY LLC	3/23/2016	18	7696	30.24	5.71	34.71	29.36	0.10	Bdl/JD	J	3/4	1,647.95
AURORA ENERGY LLC	3/24/2016	16	7574	32.11	4.93	35.45	27.52	0.10	JD		4	1,413.40
AURORA ENERGY LLC	3/29/2016	12	7716	31.99	4.16	35.71	28.14	0.11	JD		4	1,091.50
AURORA ENERGY LLC	3/30/2016	13	7642	32.31	4.18	35.81	27.70	0.11	JD		4	1,222.60
AURORA ENERGY LLC	3/31/2016	15	7741	31.85	4.24	35.23	28.68	0.11	JD		4	1,385.25
AURORA ENERGY LLC	4/1/2016	12	7723	31.82	4.28	35.95	27.95	0.11	JD		4	1,102.80
AURORA ENERGY LLC	4/5/2016	12	7666	31.80	4.77	35.48	27.95	0.12	JD		4	1,153.20
AURORA ENERGY LLC	4/6/2016	13	7705	31.70	4.66	35.12	28.53	0.12	JD		4	1,206.05
AURORA ENERGY LLC	4/7/2016	12	7602	32.54	4.49	34.80	28.18	0.12	JD		4	1,156.65
AURORA ENERGY LLC	4/8/2016	13	7766	31.23	4.49	36.04	28.25	0.11	JD		4	1,227.00
AURORA ENERGY LLC	4/12/2016	10	7756	31.50	4.66	35.46	28.39	0.12	JD		4	960.30
AURORA ENERGY LLC	4/13/2016	11	7760	31.37	4.62	35.61	28.41	0.12	JD		4	1,069.45
AURORA ENERGY LLC	4/14/2016	9	7733	31.94	4.36	35.32	28.38	0.11	JD		4	854.95
AURORA ENERGY LLC	4/15/2016	9	7768	30.79	4.70	35.74	28.78	0.11	JD		4	839.70
AURORA ENERGY LLC	4/18/2016	12	7810	31.46	4.40	35.85	28.29	0.11	JD		4	1,126.80
AURORA ENERGY LLC	4/19/2016	11	7621	32.18	4.88	34.90	28.05	0.11	JD		4	1,035.05
AURORA ENERGY LLC	4/20/2016	13	7585	32.41	4.90	34.42	28.27	0.10	JD		4	1,274.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	4/21/2016	12	7648	31.78	4.97	34.64	28.61	0.10	JD		4	1,128.20
AURORA ENERGY LLC	4/25/2016	12	7804	30.65	5.06	35.23	29.07	0.11	JD		4	1,120.80
AURORA ENERGY LLC	4/26/2016	10	7794	30.80	4.83	35.24	29.13	0.10	JD		4	1,017.70
AURORA ENERGY LLC	4/27/2016	13	7792	31.50	4.34	35.33	28.84	0.10	JD		4	1,255.45
AURORA ENERGY LLC	4/28/2016	13	7717	31.14	4.83	35.23	28.80	0.11	JD		4	1,284.75
AURORA ENERGY LLC	5/2/2016	12	7733	31.54	4.44	35.22	28.81	0.10	JD		4	1,168.35
AURORA ENERGY LLC	5/3/2016	12	7747	31.52	4.43	35.40	28.66	0.11	JD		4	1,073.35
AURORA ENERGY LLC	5/9/2016	3	7772	30.90	5.16	34.88	29.06	0.13	JD		4	288.15
AURORA ENERGY LLC	5/10/2016	3	7870	29.71	5.13	36.25	28.91	0.12	JD		4	268.35
AURORA ENERGY LLC	5/11/2016	4	7720	33.22	3.17	34.91	28.70	0.08	JD		4	372.65
AURORA ENERGY LLC	5/13/2016	8	7504	33.43	4.57	34.09	27.91	0.10	JD		4	761.40
AURORA ENERGY LLC	5/17/2016	11	7630	32.79	4.33	34.71	28.17	0.10	JD		4	1,084.05
AURORA ENERGY LLC	5/18/2016	11	7466	34.38	4.30	33.98	27.35	0.10	JD/JD		3/4	1,050.25
AURORA ENERGY LLC	5/19/2016	11	7277	32.62	7.83	33.49	26.07	0.13	JD/JD		3/4	1,127.45
AURORA ENERGY LLC	5/20/2016	12	7552	31.48	6.32	34.89	27.32	0.12	JD/JD		3/4	1,176.40
AURORA ENERGY LLC	5/23/2016	14	7661	31.33	5.63	34.90	28.15	0.12	JD/JD		3/4	1,367.20
AURORA ENERGY LLC	5/24/2016	13	7685	31.62	5.34	35.25	27.80	0.12	JD/JD		3/4	1,229.45
AURORA ENERGY LLC	5/25/2016	13	7492	32.88	5.31	34.79	27.03	0.12	JD/JD		3/4	1,237.80
AURORA ENERGY LLC	5/26/2016	10	7627	31.34	5.59	35.37	27.71	0.13	JD/JD		3/4	996.95
AURORA ENERGY LLC	5/31/2016	13	7730	30.85	5.28	36.10	27.77	0.11	JD		4	1,246.35
AURORA ENERGY LLC	6/1/2016	13	7826	30.81	4.68	36.26	28.26	0.10	JD/JD		4/3	1,188.90
AURORA ENERGY LLC	6/2/2016	12	7791	31.02	4.90	35.82	28.26	0.12	JD/JD		3/4	1,073.70
AURORA ENERGY LLC	6/3/2016	14	7647	28.04	8.54	35.38	28.04	0.21	JD/Bdl	/K	3/4	1,360.65
AURORA ENERGY LLC	6/6/2016	13	7411	30.10	8.84	34.34	26.72	0.23	Bdl/JD	K	4/3	1,274.75
AURORA ENERGY LLC	6/7/2016	11	7464	31.52	6.83	34.18	27.47	0.11	Bdl/JD	K	4/3	1,035.45
AURORA ENERGY LLC	6/8/2016	11	7491	30.78	7.37	34.34	27.51	0.14	Bdl/JD	K	4/3	1,040.50
AURORA ENERGY LLC	6/9/2016	10	7613	30.80	6.31	35.15	27.74	0.13	Bdl/JD	K	4/3	993.00
AURORA ENERGY LLC	6/13/2016	12	7632	31.54	5.50	34.94	28.02	0.12	Bdl/JD		4/3	1,190.00
AURORA ENERGY LLC	6/14/2016	12	7599	31.45	5.87	34.93	27.76	0.12	JD/JD		3/4	1,177.30
AURORA ENERGY LLC	6/16/2016	24	7514	32.67	5.39	35.16	26.78	0.12	JD/JD		3/4	2,323.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	6/20/2016	16	7606	31.88	5.51	35.05	27.57	0.10	JD/JD		3/4	1,578.60
AURORA ENERGY LLC	6/21/2016	16	7641	31.29	6.01	34.95	27.75	0.12	JD/JD		3/4	1,540.35
AURORA ENERGY LLC	6/23/2016	15	7667	31.90	5.11	34.65	28.35	0.12	JD/JD		3/4	1,438.65
AURORA ENERGY LLC	6/27/2016	12	7480	31.07	6.90	34.53	27.50	0.11	JD/JD		3/4	1,109.05
AURORA ENERGY LLC	6/28/2016	11	7637	31.39	5.94	35.68	27.00	0.12	JD/JD		3/4	1,037.70
AURORA ENERGY LLC	6/29/2016	9	7577	30.69	7.06	35.22	27.03	0.13	JD/JD		3/4	863.15
AURORA ENERGY LLC	6/30/2016	13	7574	31.03	6.80	35.12	27.06	0.13	JD/JD		3/4	1,267.15

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
EIELSON AFB - DFAS	1/5/2016	9	7520	31.96	5.18	34.80	28.07	0.12	Bdl/JD	J	4/4	840.80
EIELSON AFB - DFAS	1/6/2016	10	7660	32.32	4.25	34.80	28.64	0.11	JD		4	916.40
EIELSON AFB - DFAS	1/7/2016	10	7724	32.29	3.66	35.34	28.72	0.10	JD		4	908.10
EIELSON AFB - DFAS	1/12/2016	10	7633	32.22	4.49	35.25	28.05	0.12	Bdl/JD	J	4/4	927.90
EIELSON AFB - DFAS	1/13/2016	10	7661	32.66	3.66	35.37	28.32	0.08	JD		4	893.05
EIELSON AFB - DFAS	1/14/2016	10	7709	31.71	4.17	35.75	28.37	0.10	JD		4	888.45
EIELSON AFB - DFAS	1/15/2016	10	7778	31.00	4.60	36.33	28.08	0.12	JD		4	909.15
EIELSON AFB - DFAS	1/19/2016	12	7712	31.80	4.38	35.14	28.68	0.10	JD		4	1,071.20
EIELSON AFB - DFAS	1/20/2016	11	7723	32.23	4.18	35.17	28.42	0.12	JD		4	973.20
EIELSON AFB - DFAS	1/21/2016	15	7638	32.53	4.44	34.87	28.17	0.13	JD		4	1,379.00
EIELSON AFB - DFAS	1/22/2016	12	7624	31.93	4.92	35.16	28.00	0.11	JD		4	1,105.20
EIELSON AFB - DFAS	1/26/2016	12	7490	32.32	5.40	34.27	28.01	0.11	JD		4	1,134.75
EIELSON AFB - DFAS	1/27/2016	13	7533	31.49	5.77	34.90	27.85	0.12	Bdl/JD	J	4/4	1,215.95
EIELSON AFB - DFAS	1/28/2016	15	7573	32.67	4.75	34.63	27.96	0.10	Bdl/JD	J	4/4	1,350.75
EIELSON AFB - DFAS	2/2/2016	12	7557	32.09	4.95	35.17	27.80	0.10	JD/Bdl	/J	4/3	1,112.15
EIELSON AFB - DFAS	2/3/2016	12	7717	31.10	5.07	34.90	28.93	0.14	Bdl/JD	J	3/4	1,124.55
EIELSON AFB - DFAS	2/4/2016	13	7624	30.85	5.97	34.68	28.51	0.17	Bdl/JD	J	4/4	1,191.10
EIELSON AFB - DFAS	2/5/2016	12	7616	31.11	5.83	35.41	27.65	0.13	JD/Bdl	/J	4/4	1,132.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12
EIELSON AFB - DFAS	80214.85	7611.00	31.53	5.47	34.99	28.02	0.12
FORT WAINWRIGHT ACCOUNTING	126389.60	7620.00	31.49	5.41	35.01	28.08	0.12
OTHER COAL SALES	70008.05	7699.00	29.94	6.15	35.52	28.38	0.13
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12
Total	423697.4	7651.59	31.15	5.49	35.19	28.17	0.12

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-18-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/5/2016	15	7570	30.93	6.78	34.59	27.71	0.13	JD/JD		3/4	1,417.10
AURORA ENERGY LLC	7/6/2016	10	7661	30.50	6.07	35.20	28.23	0.11	JD/JD		3/4	999.55
AURORA ENERGY LLC	7/8/2016	15	7588	31.27	6.06	35.54	27.13	0.11	JD/JD		3/4	1,368.70
AURORA ENERGY LLC	7/11/2016	19	7496	32.08	6.04	34.43	27.45	0.11	JD/JD		3/4	1,782.30
AURORA ENERGY LLC	7/12/2016	14	7507	30.39	7.57	35.14	26.90	0.16	Bdl/JD	K	4/3	1,387.10
AURORA ENERGY LLC	7/14/2016	18	7561	29.88	7.43	35.07	27.62	0.16	Bdl/JD	K/	4/3	1,766.80
AURORA ENERGY LLC	7/18/2016	17	7711	29.16	7.11	35.83	27.90	0.17	JD/Bdl	/K	3/4	1,594.70
AURORA ENERGY LLC	7/19/2016	15	7689	29.26	6.72	35.46	28.56	0.17	Bdl/JD	K	4/3	1,378.10
AURORA ENERGY LLC	7/21/2016	18	7652	29.41	6.98	35.14	28.47	0.17	Bdl/JD	K	4/3	1,724.10
AURORA ENERGY LLC	7/25/2016	12	7689	29.04	7.41	34.83	28.73	0.17	Bdl/JD	K	4/3	1,116.65
AURORA ENERGY LLC	7/26/2016	11	7590	29.91	7.20	34.97	27.92	0.16	Bdl/JD	K	4/3	1,036.20
AURORA ENERGY LLC	7/28/2016	11	7616	29.35	7.50	35.18	27.97	0.18	Bdl/JD	K	4/3	1,042.70
AURORA ENERGY LLC	8/1/2016	14	7596	29.24	8.06	34.84	27.87	0.15	Bdl/JD	K	4/3	1,351.50
AURORA ENERGY LLC	8/2/2016	14	7456	30.31	8.00	34.62	27.08	0.15	Bdl/JD	K/	4/3	1,371.25
AURORA ENERGY LLC	8/4/2016	13	7543	30.45	7.11	34.97	27.47	0.14	Bdl/JD	K	4/3	1,234.55
AURORA ENERGY LLC	8/8/2016	19	7554	29.57	8.13	34.64	27.67	0.15	Bdl/JD	K	4/3	1,829.20
AURORA ENERGY LLC	8/9/2016	17	7555	29.32	8.20	34.99	27.50	0.16	Bdl/JD	K/	4/3	1,727.15
AURORA ENERGY LLC	8/12/2016	17	7518	28.78	8.93	35.37	26.93	0.22	JD/Bdl	/K	3/4	1,641.20
AURORA ENERGY LLC	8/15/2016	17	7662	28.43	8.18	35.09	28.30	0.21	Bdl/JD	K	4/3	1,541.00
AURORA ENERGY LLC	8/16/2016	17	7663	29.02	7.89	35.79	27.31	0.18	Bdl/JD	K	4/3	1,617.55
AURORA ENERGY LLC	8/18/2016	16	7544	29.54	7.80	35.74	26.92	0.17	Bdl/JD	K	4/3	1,515.30
AURORA ENERGY LLC	8/23/2016	19	7487	29.32	8.70	36.15	25.83	0.18	Bdl/JD	K	4/3	1,860.65
AURORA ENERGY LLC	8/24/2016	19	7632	29.26	7.19	36.57	26.99	0.16	Bdl/JD	K	4/3	1,808.85
AURORA ENERGY LLC	8/25/2016	18	7590	31.48	5.63	35.08	27.81	0.13	JD/JD		4/3	1,682.30
AURORA ENERGY LLC	8/29/2016	19	7289	30.74	9.14	34.44	25.70	0.22	JD/JD		4/3	1,838.20
AURORA ENERGY LLC	8/30/2016	18	7582	30.55	6.91	35.46	27.09	0.15	JD/JD		3/4	1,697.80
AURORA ENERGY LLC	9/2/2016	26	7500	30.40	7.65	35.22	26.74	0.14	JD/JD		3/4	2,510.75
AURORA ENERGY LLC	9/6/2016	18	7450	32.43	6.09	34.66	26.83	0.12	JD/JD		4/3	1,694.70
AURORA ENERGY LLC	9/7/2016	17	7524	31.76	5.90	35.65	26.70	0.12	JD/Bdl	/K	3/4	1,605.50
AURORA ENERGY LLC	9/8/2016	10	7550	30.91	6.94	34.82	27.35	0.13	JD/Bdl	/K	4/4	953.55

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	9/9/2016	10	7573	30.37	6.68	35.37	27.58	0.12	Bdl/JD	K	4/3	959.50
AURORA ENERGY LLC	9/27/2016	7	7558	29.53	7.77	36.09	26.62	0.14	JD/JD		3/4	660.95
AURORA ENERGY LLC	9/30/2016	18	7663	29.00	7.19	36.55	27.26	0.12	JD/Bdl	/K	3/4	1,783.60
AURORA ENERGY LLC	10/3/2016	24	7551	30.59	7.00	35.86	26.56	0.11	JD/Bdl	/K	3/4	2,244.55
AURORA ENERGY LLC	10/5/2016	28	7514	30.13	7.52	34.79	27.56	0.12	Bdl/JD	K	4/3	2,682.10
AURORA ENERGY LLC	10/10/2016	20	7615	29.98	6.97	35.09	27.97	0.12	Bdl/JD	K	4/3	1,895.45
AURORA ENERGY LLC	10/11/2016	21	7415	29.36	9.27	34.88	26.50	0.12	JD		4	1,974.25
AURORA ENERGY LLC	10/17/2016	14	7725	30.51	5.80	35.47	28.22	0.11	JD		4	1,327.05
AURORA ENERGY LLC	10/18/2016	10	7666	30.86	5.74	35.75	27.65	0.11	JD/JD		3/4	910.90
AURORA ENERGY LLC	10/19/2016	11	7674	30.61	5.79	35.44	28.17	0.10	JD/JD		3/4	940.90
AURORA ENERGY LLC	10/24/2016	12	7760	29.11	6.56	36.37	27.97	0.12	JD/JD		3/4	1,137.45
AURORA ENERGY LLC	10/25/2016	12	7729	29.22	6.51	36.28	27.99	0.12	Bdl		6	1,063.15
AURORA ENERGY LLC	10/26/2016	14	7708	28.38	7.47	36.44	27.71	0.12	Bdl/JD		6/4	1,171.40
AURORA ENERGY LLC	10/27/2016	14	7765	27.43	7.69	37.53	27.36	0.13	Bdl/JD		6/4	1,243.80
AURORA ENERGY LLC	10/31/2016	14	7742	26.38	8.92	37.76	26.94	0.14	Bdl		6	1,220.95
AURORA ENERGY LLC	11/1/2016	15	7705	26.55	9.09	38.27	26.09	0.14	Bdl		6	1,290.10
AURORA ENERGY LLC	11/2/2016	14	7726	26.53	8.80	37.76	26.91	0.14	Bdl		6	1,238.05
AURORA ENERGY LLC	11/3/2016	13	7774	26.33	8.55	37.90	27.23	0.14	Bdl		6	1,100.70
AURORA ENERGY LLC	11/7/2016	15	7680	27.17	8.92	37.45	26.47	0.13	Bdl		6	1,346.80
AURORA ENERGY LLC	11/8/2016	15	7646	26.81	9.38	37.93	25.89	0.14	Bdl		6	1,315.35
AURORA ENERGY LLC	11/9/2016	15	7631	27.00	9.17	37.46	26.37	0.14	Bdl		6	1,316.60
AURORA ENERGY LLC	11/10/2016	16	7714	26.75	8.56	37.61	27.09	0.13	Bdl		6	1,394.90
AURORA ENERGY LLC	11/14/2016	16	7658	26.44	9.11	37.77	26.68	0.14	Bdl		6	1,432.15
AURORA ENERGY LLC	11/16/2016	16	7680	27.17	8.40	37.84	26.60	0.14	Bdl		6	1,436.00
AURORA ENERGY LLC	11/17/2016	15	7748	27.26	7.86	37.64	27.24	0.13	Bdl		6	1,320.90
AURORA ENERGY LLC	11/21/2016	16	7710	27.01	8.43	37.84	26.73	0.13	Bdl		6	1,456.15
AURORA ENERGY LLC	11/22/2016	19	7751	27.30	8.01	38.35	26.34	0.13	Bdl		6	1,754.65
AURORA ENERGY LLC	11/23/2016	17	7736	27.32	7.92	38.15	26.61	0.13	Bdl		6	1,432.75
AURORA ENERGY LLC	11/28/2016	10	7705	27.45	7.89	37.39	27.28	0.13	Bdl		6	876.20
AURORA ENERGY LLC	11/29/2016	10	7464	27.88	9.89	36.20	26.04	0.13	Bdl		6	923.55
AURORA ENERGY LLC	11/30/2016	10	7586	29.83	6.92	36.51	26.75	0.13	JD		4	881.80
AURORA ENERGY LLC	12/1/2016	11	6899	28.06	14.52	32.87	24.55	0.12	Bdl/JD		6/4	913.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	12/5/2016	12	7660	30.15	6.54	35.11	28.21	0.15	JD	4	1,048.05
AURORA ENERGY LLC	12/6/2016	12	7635	29.90	6.82	35.74	27.54	0.14	JD	4	1,034.60
AURORA ENERGY LLC	12/7/2016	11	7691	30.39	5.66	35.64	28.32	0.12	Bdl/JD	6/4	934.95
AURORA ENERGY LLC	12/8/2016	12	7684	29.22	7.21	37.06	26.52	0.12	JD	4	1,028.90
AURORA ENERGY LLC	12/12/2016	15	7734	28.36	7.03	36.54	28.08	0.16	JD	4	1,336.05
AURORA ENERGY LLC	12/13/2016	15	7656	27.80	8.19	37.25	26.77	0.14	JD	4	1,297.80
AURORA ENERGY LLC	12/14/2016	15	7683	27.72	7.99	36.90	27.40	0.14	JD	4	1,347.60
AURORA ENERGY LLC	12/15/2016	8	7679	27.93	7.85	36.68	27.55	0.15	JD/Bdl	4/6	735.90
AURORA ENERGY LLC	12/19/2016	18	7626	27.91	8.63	37.07	26.40	0.14	Bdl/JD	6/4	1,625.50
AURORA ENERGY LLC	12/20/2016	23	7529	28.73	8.36	36.18	26.74	0.13	Bdl	6	2,003.15
AURORA ENERGY LLC	12/21/2016	8	7177	33.28	5.98	34.15	26.60	0.11	JD	4	702.25
AURORA ENERGY LLC	12/22/2016	7	7498	30.41	6.92	35.74	26.93	0.13	JD	4	625.90
AURORA ENERGY LLC	12/27/2016	13	7617	30.42	6.60	35.98	27.01	0.12	JD	4	1,202.80
AURORA ENERGY LLC	12/28/2016	13	7774	30.23	5.76	36.52	27.49	0.13	JD/Bdl	4/6	1,132.75
AURORA ENERGY LLC	12/29/2016	14	7656	30.08	6.37	36.50	27.06	0.13	Bdl/JD	6/4	1,242.95
AURORA ENERGY LLC	12/29/2016	4	7427	30.47	7.75	35.36	26.42	0.13	Bdl/JD	6/4	355.05
AURORA ENERGY LLC	12/31/2016	14	7668	27.72	8.27	37.22	26.79	0.14	Bdl/JD	6/4	1,292.45

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	107687.35	7604.00	29.23	7.61	35.99	27.17	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 1-11-17

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/3/2017	18	7477	30.01	7.72	36.14	26.13	0.14	JD		4	1,692.15
AURORA ENERGY LLC	1/4/2017	19	7629	29.79	6.61	35.98	27.62	0.14	JD		4	1,625.15
AURORA ENERGY LLC	1/5/2017	19	7546	29.25	7.60	35.83	27.32	0.16	JD/STK		4/L	1,722.00
AURORA ENERGY LLC	1/6/2017	19	7556	32.13	5.19	35.58	27.11	0.12	JD		4	1,667.00
AURORA ENERGY LLC	1/10/2017	16	7711	31.53	4.83	35.98	27.66	0.11	JD		4	1,414.60
AURORA ENERGY LLC	1/11/2017	11	7587	32.46	4.80	35.38	27.37	0.12	JD		4	960.60
AURORA ENERGY LLC	1/12/2017	15	7557	32.36	5.01	35.04	27.60	0.12	JD		4	1,360.55
AURORA ENERGY LLC	1/13/2017	10	7657	31.58	5.05	35.99	27.38	0.15	JD		4	911.65
AURORA ENERGY LLC	1/16/2017	11	7484	33.02	5.28	34.59	27.11	0.13	JD		4	953.00
AURORA ENERGY LLC	1/17/2017	7	7796	31.16	4.49	35.71	28.65	0.11	JD		4	560.65
AURORA ENERGY LLC	1/19/2017	8	7453	32.25	5.64	35.11	27.00	0.13	JD		4	622.05
AURORA ENERGY LLC	1/20/2017	7	7517	33.70	4.45	34.77	27.08	0.11	JD		4	636.35
AURORA ENERGY LLC	1/21/2017	14	7599	33.03	4.28	34.94	27.75	0.10	JD		4	1,222.40
AURORA ENERGY LLC	1/23/2017	11	7669	32.37	4.38	35.00	28.26	0.10	JD		4	970.45
AURORA ENERGY LLC	1/24/2017	11	7726	32.24	4.34	35.68	27.75	0.10	JD		4	941.95
AURORA ENERGY LLC	1/25/2017	11	7644	32.08	4.71	35.28	27.94	0.09	JD		4	974.55
AURORA ENERGY LLC	1/26/2017	8	7572	32.05	5.46	34.92	27.57	0.10	JD		4	718.10
AURORA ENERGY LLC	1/27/2017	11	7639	31.03	5.90	36.14	26.94	0.12	JD		4	981.45
AURORA ENERGY LLC	1/30/2017	11	7572	32.29	5.53	35.74	26.45	0.12	JD		4	953.15
AURORA ENERGY LLC	1/31/2017	11	7217	32.88	6.93	34.88	25.31	0.14	JD		4	975.95
AURORA ENERGY LLC	2/1/2017	24	6822	34.48	8.09	32.84	24.60	0.14	JD		4	2,255.10
AURORA ENERGY LLC	2/1/2017	4	7170	33.55	6.67	33.62	26.17	0.13	JD		4	355.30
AURORA ENERGY LLC	2/1/2017	3	7252	33.71	5.99	33.75	26.56	0.13	JD		4	267.25
AURORA ENERGY LLC	2/6/2017	9	7551	32.85	4.86	34.74	27.55	0.12	JD		4	790.05
AURORA ENERGY LLC	2/7/2017	10	7554	33.29	4.68	34.92	27.12	0.11	JD		4	877.60
AURORA ENERGY LLC	2/8/2017	10	7691	32.19	4.46	35.15	28.22	0.11	JD		4	869.65
AURORA ENERGY LLC	2/9/2017	9	7651	32.24	4.61	35.16	28.01	0.12	JD		4	796.00
AURORA ENERGY LLC	2/10/2017	10	7729	31.63	4.62	35.76	28.00	0.11	JD		4	875.35
AURORA ENERGY LLC	2/13/2017	9	7625	32.37	4.69	35.17	27.77	0.13	JD		4	790.10
AURORA ENERGY LLC	2/14/2017	8	7567	32.56	4.97	35.16	27.32	0.11	JD		4	692.50

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	2/15/2017	10	7634	32.54	4.49	35.36	27.61	0.11	JD	4	869.00
AURORA ENERGY LLC	2/16/2017	8	7498	33.04	4.98	35.17	26.82	0.12	JD	4	717.70
AURORA ENERGY LLC	2/17/2017	9	7463	33.10	5.10	34.31	27.50	0.12	JD	4	814.60
AURORA ENERGY LLC	2/21/2017	8	7588	32.49	4.85	35.18	27.48	0.12	JD	4	701.75
AURORA ENERGY LLC	2/22/2017	11	7557	33.17	4.44	34.73	27.66	0.11	JD	4	980.00
AURORA ENERGY LLC	2/23/2017	12	7563	32.96	4.14	35.22	27.69	0.10	JD	4	1,045.50
AURORA ENERGY LLC	2/24/2017	12	7688	32.39	4.22	35.42	27.98	0.11	JD	4	957.20
AURORA ENERGY LLC	2/27/2017	14	7690	32.22	4.51	35.99	27.28	0.11	JD	4	1,176.20
AURORA ENERGY LLC	3/1/2017	13	7165	33.78	5.52	34.38	26.32	0.11	JD	4	1,197.25
AURORA ENERGY LLC	3/2/2017	12	7074	33.61	5.95	34.70	25.75	0.11	JD	4	1,089.10
AURORA ENERGY LLC	3/3/2017	17	7451	31.82	5.88	35.09	27.21	0.11	JD	4	1,454.95
AURORA ENERGY LLC	3/6/2017	26	7216	32.35	6.16	35.29	26.19	0.11	JD	4	2,389.10
AURORA ENERGY LLC	3/8/2017	13	7505	31.11	6.36	35.34	27.20	0.12	JD/Bdl	4/6	1,072.30
AURORA ENERGY LLC	3/11/2017	28	7281	33.37	5.39	35.01	26.24	0.12	JD/Bdl	4/6	2,582.40
AURORA ENERGY LLC	3/11/2017	12	7569	32.00	4.79	36.18	27.04	0.10	JD/Bdl	4/6	1,076.05
AURORA ENERGY LLC	3/14/2017	13	7651	31.55	4.89	35.87	27.69	0.11	JD	4	1,119.25
AURORA ENERGY LLC	3/15/2017	15	7583	31.90	5.01	35.77	27.32	0.12	JD	4	1,321.40
AURORA ENERGY LLC	3/20/2017	13	7524	32.29	4.83	35.84	27.04	0.12	JD	4	1,120.40
AURORA ENERGY LLC	3/21/2017	12	7579	32.14	4.66	35.78	27.42	0.12	JD	4	1,035.50
AURORA ENERGY LLC	3/22/2017	12	7667	32.19	4.11	35.51	28.20	0.11	JD	4	1,045.35
AURORA ENERGY LLC	3/23/2017	14	7595	31.37	5.88	34.77	27.97	0.13	JD/GRP	4/C	1,240.20
AURORA ENERGY LLC	3/27/2017	14	7651	31.46	5.35	35.39	27.81	0.13	JD/GRP	4/C	1,246.80
AURORA ENERGY LLC	3/28/2017	14	7626	31.21	5.57	34.76	28.47	0.13	JD/GRP	4/M	1,254.00
AURORA ENERGY LLC	3/29/2017	10	7571	31.75	5.59	34.86	27.81	0.13	JD/GRP	4/M	902.05
AURORA ENERGY LLC	3/30/2017	13	7577	31.50	5.45	35.40	27.65	0.12	JD/GRP	4/M	1,119.90
AURORA ENERGY LLC	4/3/2017	13	7646	31.95	4.45	36.24	27.36	0.11	JD	4	1,123.15
AURORA ENERGY LLC	4/4/2017	13	7653	32.13	4.28	36.07	27.52	0.10	JD	4	1,148.05
AURORA ENERGY LLC	4/5/2017	13	7681	31.32	5.21	35.50	27.97	0.13	JD/GRP	4/C	1,164.90
AURORA ENERGY LLC	4/6/2017	8	7615	32.59	4.35	35.95	27.12	0.10	JD	4	726.65
AURORA ENERGY LLC	4/10/2017	11	7682	32.21	4.28	37.03	26.49	0.11	JD	4	977.45
AURORA ENERGY LLC	4/11/2017	12	7681	31.95	4.39	35.97	27.69	0.10	JD	4	1,085.65
AURORA ENERGY LLC	4/12/2017	7	7552	33.01	4.28	35.11	27.60	0.11	JD	4	674.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	4/13/2017	11	7385	34.02	4.57	34.56	26.86	0.10	JD	4	1,018.95
AURORA ENERGY LLC	4/18/2017	15	7644	32.05	4.35	36.70	26.91	0.11	JD	4	1,391.00
AURORA ENERGY LLC	4/19/2017	7	7663	31.22	5.39	35.74	27.64	0.13	JD	4	624.95
AURORA ENERGY LLC	4/20/2017	15	7624	32.50	4.35	35.84	27.31	0.11	JD	4	1,314.50
AURORA ENERGY LLC	4/21/2017	17	7590	31.89	4.70	35.91	27.50	0.11	JD	4	1,591.90
AURORA ENERGY LLC	4/24/2017	15	7675	31.63	4.45	36.49	27.44	0.10	JD	4	1,391.90
AURORA ENERGY LLC	4/25/2017	13	7577	33.14	4.06	35.38	27.44	0.11	JD	4	1,272.55
AURORA ENERGY LLC	4/26/2017	9	7592	33.84	3.51	35.03	27.62	0.10	JD	4	894.20
AURORA ENERGY LLC	4/27/2017	8	7621	32.87	3.81	36.16	27.16	0.10	JD	4	775.45
AURORA ENERGY LLC	5/1/2017	7	7734	31.63	4.44	36.23	27.71	0.12	JD	4	645.70
AURORA ENERGY LLC	5/2/2017	6	7739	30.89	4.60	36.41	28.10	0.11	JD	4	563.10
AURORA ENERGY LLC	5/3/2017	4	7825	30.98	4.22	36.19	28.62	0.11	JD	4	371.55
AURORA ENERGY LLC	5/8/2017	4	7461	33.26	4.78	35.09	26.88	0.12	JD	4	381.75
AURORA ENERGY LLC	5/9/2017	6	7489	32.64	5.06	34.89	27.42	0.11	JD	4	517.50
AURORA ENERGY LLC	5/11/2017	4	7538	31.86	5.27	35.86	27.02	0.11	JD	4	359.75
AURORA ENERGY LLC	5/15/2017	9	7599	31.85	4.95	36.29	26.91	0.10	JD	4	807.40
AURORA ENERGY LLC	5/16/2017	8	7633	31.97	4.66	36.40	26.98	0.10	JD	4	739.40
AURORA ENERGY LLC	5/17/2017	5	7574	33.83	4.08	34.88	27.20	0.09	JD	4	466.55
AURORA ENERGY LLC	5/18/2017	4	7650	33.31	3.42	35.81	27.47	0.09	JD	4	354.65
AURORA ENERGY LLC	5/19/2017	7	7656	32.09	4.24	35.89	27.79	0.10	JD	4	603.30
AURORA ENERGY LLC	5/22/2017	16	7756	31.40	4.24	36.49	27.87	0.10	JD	4	1,430.45
AURORA ENERGY LLC	5/23/2017	12	7512	33.57	4.17	35.75	26.51	0.13	JD	4	1,090.40
AURORA ENERGY LLC	5/24/2017	12	7669	32.70	3.95	35.99	27.36	0.12	JD	4	1,097.30
AURORA ENERGY LLC	5/26/2017	14	7657	31.91	4.59	36.48	27.02	0.11	JD	4	1,311.30
AURORA ENERGY LLC	5/30/2017	9	7675	31.80	4.72	36.29	27.19	0.11	JD	4	835.35
AURORA ENERGY LLC	5/31/2017	8	7693	31.83	4.71	36.93	26.53	0.11	JD	4	747.65
AURORA ENERGY LLC	6/1/2017	3	7701	31.47	4.41	37.05	27.07	0.10	JD	4	265.40
AURORA ENERGY LLC	6/2/2017	4	7777	31.10	4.13	36.64	28.13	0.10	JD	4	346.30
AURORA ENERGY LLC	6/5/2017	12	7650	32.12	4.55	35.36	27.98	0.10	JD	4	1,061.75
AURORA ENERGY LLC	6/6/2017	13	7594	32.33	4.47	35.40	27.81	0.11	JD	4	1,165.40
AURORA ENERGY LLC	6/8/2017	12	7636	32.08	4.40	35.99	27.53	0.10	JD	4	1,067.80
AURORA ENERGY LLC	6/9/2017	11	7674	31.80	4.30	36.21	27.70	0.11	JD	4	1,011.25

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	6/12/2017	12	7609	32.30	4.32	36.00	27.38	0.10	JD	4	1,063.85
AURORA ENERGY LLC	6/13/2017	13	7682	31.87	4.25	36.35	27.54	0.09	JD	4	1,140.90
AURORA ENERGY LLC	6/15/2017	12	7675	31.97	4.75	36.23	27.06	0.12	JD	4	1,093.80
AURORA ENERGY LLC	6/16/2017	13	7665	32.28	4.53	35.98	27.21	0.12	JD	4	1,167.30
AURORA ENERGY LLC	6/19/2017	11	7699	32.34	3.91	36.45	27.31	0.10	JD	4	982.95
AURORA ENERGY LLC	6/20/2017	12	7714	32.35	4.07	35.98	27.60	0.10	JD	4	1,115.05
AURORA ENERGY LLC	6/22/2017	12	7555	33.32	4.39	35.52	26.77	0.12	JD	4	1,083.45
AURORA ENERGY LLC	6/23/2017	13	7642	32.79	4.37	35.68	27.17	0.12	JD	4	1,163.90
AURORA ENERGY LLC	6/26/2017	8	7699	32.23	4.30	35.95	27.52	0.12	JD	4	701.50
AURORA ENERGY LLC	6/27/2017	8	7754	31.81	4.08	36.33	27.78	0.11	JD	4	701.85
AURORA ENERGY LLC	6/28/2017	8	7711	31.90	4.58	36.91	26.61	0.11	JD	4	752.00
AURORA ENERGY LLC	6/29/2017	8	7760	31.78	4.09	36.29	27.85	0.10	JD	4	696.20

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	106040.35	7567.00	32.20	4.98	35.56	27.26	0.11

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-5-17

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/3/2017	12	7517	32.85	4.69	35.25	27.22	0.11	JD		4	1,086.15
AURORA ENERGY LLC	7/5/2017	13	7551	33.12	4.11	35.68	27.09	0.11	JD		4	1,188.30
AURORA ENERGY LLC	7/6/2017	13	7595	33.11	4.06	35.63	27.20	0.11	JD		4	1,252.50
AURORA ENERGY LLC	7/7/2017	12	7494	33.16	4.13	35.09	27.62	0.11	JD		4	1,164.50
AURORA ENERGY LLC	7/10/2017	11	7516	34.02	4.15	34.55	27.28	0.10	JD		4	1,011.85
AURORA ENERGY LLC	7/11/2017	12	7258	33.79	5.22	35.08	25.92	0.10	JD		4	1,161.40
AURORA ENERGY LLC	7/13/2017	12	6947	34.61	6.24	34.51	24.64	0.10	JD		4	1,145.45
AURORA ENERGY LLC	7/14/2017	11	6816	34.98	6.18	34.21	24.63	0.11	JD		4	1,072.45
AURORA ENERGY LLC	7/17/2017	12	7074	34.52	5.03	34.87	25.58	0.10	JD		4	1,122.60
AURORA ENERGY LLC	7/18/2017	13	7306	33.58	4.88	35.16	26.38	0.11	JD		4	1,222.85
AURORA ENERGY LLC	7/20/2017	13	7165	33.99	5.19	35.42	25.40	0.10	JD		4	1,243.85
AURORA ENERGY LLC	7/25/2017	9	7331	33.62	4.81	35.34	26.24	0.11	JD		4	853.00
AURORA ENERGY LLC	7/26/2017	8	7372	33.16	4.93	35.34	26.58	0.11	JD		4	766.70
AURORA ENERGY LLC	7/27/2017	9	7444	33.20	4.78	35.50	26.53	0.11	JD		4	862.10
AURORA ENERGY LLC	7/28/2017	8	7326	33.62	5.09	35.23	26.07	0.11	JD		4	772.70
AURORA ENERGY LLC	7/31/2017	12	7067	34.65	5.05	34.54	25.77	0.11	JD		4	1,152.10
AURORA ENERGY LLC	8/1/2017	12	7141	33.99	4.94	34.81	26.27	0.11	JD		4	1,150.10
AURORA ENERGY LLC	8/3/2017	12	7164	33.98	5.14	34.57	26.31	0.11	JD		4	1,147.95
AURORA ENERGY LLC	8/4/2017	12	7286	33.90	4.79	35.05	26.27	0.11	JD		4	1,145.30
AURORA ENERGY LLC	8/7/2017	9	7378	33.17	5.03	34.99	26.81	0.11	JD		4	782.15
AURORA ENERGY LLC	8/10/2017	19	7253	33.46	5.18	35.37	25.99	0.11	JD		4	1,810.35
AURORA ENERGY LLC	8/11/2017	20	7318	33.17	5.03	35.36	26.46	0.12	JD		4	1,908.20
AURORA ENERGY LLC	8/14/2017	11	7460	33.07	4.73	35.90	26.91	0.11	JD		4	1,010.35
AURORA ENERGY LLC	8/15/2017	12	7178	34.62	5.07	34.00	26.32	0.12	JD		4	1,140.70
AURORA ENERGY LLC	8/17/2017	12	7233	35.07	4.27	34.48	26.19	0.11	JD		4	1,118.45
AURORA ENERGY LLC	8/18/2017	11	7230	34.34	4.20	35.09	26.38	0.10	JD		4	1,012.25
AURORA ENERGY LLC	8/21/2017	12	7183	34.66	4.57	34.70	26.08	0.10	JD		4	1,132.10
AURORA ENERGY LLC	8/22/2017	11	6965	35.25	5.44	33.99	25.32	0.11	JD		4	1,063.00
AURORA ENERGY LLC	8/24/2017	13	7340	33.83	4.89	35.51	25.78	0.11	JD		4	1,237.30
AURORA ENERGY LLC	8/25/2017	12	7298	33.44	4.79	35.35	26.43	0.10	JD		4	1,143.30

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	8/29/2017	13	7624	32.09	3.98	36.19	27.75	0.09	JD	4	1,160.75
AURORA ENERGY LLC	8/30/2017	12	7693	31.67	4.26	35.95	28.12	0.11	JD	4	1,089.50
AURORA ENERGY LLC	8/31/2017	13	7679	31.66	4.54	36.00	27.81	0.12	JD	4	1,198.20
AURORA ENERGY LLC	9/1/2017	16	7556	31.91	4.68	35.57	27.85	0.10	JD	4	1,489.65
AURORA ENERGY LLC	9/5/2017	15	7539	32.49	4.50	35.78	27.23	0.10	JD	4	1,313.40
AURORA ENERGY LLC	9/6/2017	14	7605	32.58	4.13	35.67	27.62	0.10	JD	4	1,306.00
AURORA ENERGY LLC	9/7/2017	14	7651	32.11	4.32	35.95	27.62	0.09	JD	4	1,299.30
AURORA ENERGY LLC	9/8/2017	10	7585	31.81	4.55	35.94	27.71	0.10	JD	4	909.40
AURORA ENERGY LLC	9/11/2017	13	7579	32.39	4.29	35.79	27.54	0.10	JD	4	1,150.80
AURORA ENERGY LLC	9/12/2017	14	7570	32.66	4.03	35.18	28.14	0.09	JD	4	1,235.95
AURORA ENERGY LLC	9/14/2017	14	7678	31.81	4.31	35.96	27.92	0.10	JD	4	1,318.55
AURORA ENERGY LLC	9/18/2017	9	7664	31.53	4.49	35.95	28.03	0.11	JD	4	813.25
AURORA ENERGY LLC	9/19/2017	10	7672	31.57	4.48	35.65	28.30	0.10	JD	4	900.45
AURORA ENERGY LLC	9/21/2017	10	7631	31.22	4.92	36.67	27.20	0.10	JD	4	922.80
AURORA ENERGY LLC	9/22/2017	9	7661	31.07	5.17	36.47	27.30	0.12	JD	4	832.35
AURORA ENERGY LLC	9/25/2017	14	7589	32.54	4.30	35.50	27.67	0.09	JD	4	1,297.15
AURORA ENERGY LLC	9/26/2017	14	7566	32.73	4.36	35.38	27.54	0.10	JD	4	1,304.80
AURORA ENERGY LLC	9/28/2017	12	7661	32.02	4.42	36.00	27.57	0.11	JD	4	1,105.45
AURORA ENERGY LLC	9/29/2017	8	7647	31.64	4.46	35.89	28.01	0.10	JD	4	747.05
AURORA ENERGY LLC	10/2/2017	9	7605	32.57	4.32	35.30	27.82	0.10	JD	4	844.05
AURORA ENERGY LLC	10/5/2017	9	7616	32.89	4.09	35.23	27.80	0.10	JD	4	818.45
AURORA ENERGY LLC	10/6/2017	8	7615	32.44	4.76	35.48	27.33	0.11	JD	4	735.40
AURORA ENERGY LLC	10/9/2017	17	7741	31.67	4.13	36.41	27.80	0.11	JD	4	1,505.25
AURORA ENERGY LLC	10/12/2017	18	7559	32.46	4.67	35.40	27.48	0.11	JD	4	1,721.25
AURORA ENERGY LLC	10/13/2017	17	7502	33.04	4.45	35.28	27.23	0.11	JD	4	1,610.35
AURORA ENERGY LLC	10/16/2017	16	7505	32.67	4.78	35.05	27.50	0.09	JD	4	1,462.45
AURORA ENERGY LLC	10/19/2017	16	7635	32.62	4.06	35.25	28.08	0.09	JD	4	1,483.05
AURORA ENERGY LLC	10/20/2017	16	7771	30.64	4.79	36.18	28.40	0.11	JD	4	1,506.45
AURORA ENERGY LLC	10/23/2017	11	7512	32.84	4.78	34.95	27.43	0.11	JD	4	1,055.65
AURORA ENERGY LLC	10/24/2017	10	7659	32.80	3.76	35.58	27.85	0.10	JD	4	960.95
AURORA ENERGY LLC	10/26/2017	10	7778	31.71	3.93	36.18	28.18	0.11	JD	4	935.50
AURORA ENERGY LLC	10/27/2017	12	[illegible]	[illegible]	[illegible]	[illegible]	28.56	0.11	JD	4	1,090.80

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	10/30/2017	17	7638	31.96	4.43	35.98	27.64	0.10	JD	4	1,583.00
AURORA ENERGY LLC	10/31/2017	15	7737	32.08	3.80	35.41	28.72	0.09	JD	4	1,398.05
AURORA ENERGY LLC	11/2/2017	15	7695	31.20	4.63	36.13	28.04	0.10	JD	4	1,375.15
AURORA ENERGY LLC	11/3/2017	16	7568	31.90	5.28	35.76	27.07	0.10	JD	4	1,498.40
AURORA ENERGY LLC	11/6/2017	17	7608	31.44	5.45	34.85	28.27	0.10	JD	4	1,507.55
AURORA ENERGY LLC	11/7/2017	25	7199	33.84	6.32	33.54	26.31	0.09	JD	4	2,432.20
AURORA ENERGY LLC	11/9/2017	7	7639	32.53	4.28	35.73	27.47	0.08	JD	4	600.95
AURORA ENERGY LLC	11/10/2017	17	7717	30.82	4.79	36.38	28.02	0.09	JD	4	1,518.10
AURORA ENERGY LLC	11/13/2017	6	7373	33.38	5.42	34.41	26.79	0.11	JD	4	560.55
AURORA ENERGY LLC	11/14/2017	7	7599	32.39	4.85	35.41	27.35	0.13	JD	4	677.50
AURORA ENERGY LLC	11/16/2017	9	7624	31.94	4.82	35.41	27.84	0.11	JD	4	820.35
AURORA ENERGY LLC	11/20/2017	11	7626	32.25	4.95	35.18	27.62	0.11	JD	4	995.15
AURORA ENERGY LLC	11/21/2017	12	7635	31.90	4.96	35.51	27.63	0.10	JD	4	1,060.50
AURORA ENERGY LLC	11/22/2017	11	7629	31.87	4.81	35.55	27.77	0.10	JD	4	943.05
AURORA ENERGY LLC	11/24/2017	9	7651	31.86	5.02	35.92	27.20	0.12	JD	4	822.90
AURORA ENERGY LLC	11/27/2017	14	7651	31.89	4.89	35.59	27.65	0.12	JD	4	1,257.20
AURORA ENERGY LLC	11/28/2017	20	7615	31.98	4.99	35.71	27.32	0.12	JD	4	1,793.75
AURORA ENERGY LLC	11/30/2017	21	7709	30.84	5.07	35.82	28.27	0.11	JD	4	1,894.15
AURORA ENERGY LLC	12/1/2017	21	7729	30.82	4.85	35.86	28.47	0.12	JD	4	1,908.30
AURORA ENERGY LLC	12/4/2017	17	7826	30.71	4.58	35.95	28.76	0.11	JD	4	1,546.15
AURORA ENERGY LLC	12/5/2017	17	7744	31.15	4.70	35.94	28.21	0.11	JD	4	1,532.85
AURORA ENERGY LLC	12/7/2017	16	7705	31.63	4.59	36.11	27.68	0.11	JD	4	1,428.20
AURORA ENERGY LLC	12/8/2017	15	7601	32.26	4.91	35.14	27.70	0.11	JD	4	1,388.25
AURORA ENERGY LLC	12/11/2017	15	7797	31.63	3.60	35.87	28.90	0.09	JD	4	1,388.65
AURORA ENERGY LLC	12/12/2017	15	7660	30.94	5.44	36.04	27.59	0.10	JD	4	1,419.85
AURORA ENERGY LLC	12/14/2017	16	7730	30.96	5.02	35.96	28.06	0.10	JD	4	1,446.45
AURORA ENERGY LLC	12/18/2017	13	7651	32.79	3.74	34.77	28.71	0.09	JD	4	1,162.00
AURORA ENERGY LLC	12/19/2017	14	7671	32.52	3.99	35.38	28.13	0.09	JD	4	1,281.55
AURORA ENERGY LLC	12/21/2017	14	7678	32.56	4.03	35.53	27.89	0.08	JD	4	1,276.25
AURORA ENERGY LLC	12/22/2017	13	7713	32.05	3.93	35.61	28.41	0.09	JD	4	1,194.20
AURORA ENERGY LLC	12/26/2017	10	7713	32.68	3.47	35.50	28.34	0.08	JD	4	900.45
AURORA ENERGY LLC	12/27/2017	11	[illegible]	[illegible]	[illegible]	[illegible]	28.38	0.10	JD	4	972.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	12/28/2017	11	7766	31.21	4.38	35.91	28.51	0.09	JD	4	975.75
AURORA ENERGY LLC	12/29/2017	10	7711	31.41	4.64	35.99	27.96	0.10	JD	4	876.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	114440.00	7529.00	32.52	4.68	35.45	27.36	0.10

This analysis is representative of the coal shipped.
The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Ben Ziegman **Date:** 1/4/18

Ben Ziegman

Signature

Appendix D (Professional Memos)

ENVIRONMENT
& HEALTH

MEMO

To **David Fish, Aurora Energy LLC**
From **Till Stoeckenius**
Subject **Summary of issues related to SO_2 precursor demonstration for Fairbanks**

Date November 15, 2018

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The Alaska Department of Environmental Conservation (ADEC) is currently developing a State Implementation Plan (SIP) for the Fairbanks North Star Borough serious $PM_{2.5}$ nonattainment area (NAA). Fairbanks was reclassified from a moderate $PM_{2.5}$ NAA to a serious $PM_{2.5}$ NAA in June 2017; the serious area SIP is due by December 2018.

As provided for in 40 CFR 51.1006, states can reduce the regulatory burden of complying with $PM_{2.5}$ NAA requirements in the Clean Air Act by conducting $PM_{2.5}$ precursor demonstrations showing that one or more precursors involved in formation of secondary $PM_{2.5}$ do not significantly contribute to violations of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). The current ADEC draft serious area SIP preparation plan includes precursor demonstrations for ammonia (NH_3), nitrogen oxides (NO_x), and volatile organic compounds (VOCs) which conclude that each of these three precursors do not significantly contribute to nonattainment. ADEC did not perform a precursor demonstration for sulfur dioxide (SO_2).

A draft Best Available Control Technology (BACT) demonstration completed by the ADEC as required by the CAA for serious NAAs identifies dry sorbent injection as BACT for the four major SO_2 sources in the Fairbanks NAA. In recognition of the possibility that the SIP may include a requirement for SO_2 controls on their sources without a clear indication of the potential benefits of such controls for reducing ambient $PM_{2.5}$ concentrations, owners of the four major SO_2 sources in the Fairbanks NAA requested (via Aurora Energy) Ramboll's assistance with evaluating possible approaches to conducting a successful major source SO_2 precursor demonstration for Fairbanks.

In accordance with our letter agreement with Aurora of 18 September, Ramboll performed research and analysis related to an SO_2 precursor demonstration for the Fairbanks 24-hour $PM_{2.5}$ serious nonattainment area (NAA). Ramboll reviewed documents describing data analysis and modeling conducted by ADEC and its contractors for the 2014 Fairbanks moderate area SIP and draft analyses and plans for developing the serious NAA SIP. This included detailed descriptions of emission inventory development, meteorological and photochemical dispersion modeling methods and related sensitivity analyses, air monitoring data analyses and receptor modeling studies and other related materials. Representatives from Ramboll, Aurora Energy and owners of the other major SO_2 sources located within the Fairbanks NAA, along with ADEC and EPA Region X, participated in a conference call to discuss issues involved in conducting a successful major source SO_2 precursor demonstration. We also had several one-on-one conversations with David Fish of Aurora and Robert Ellerman of EPA Region X. A common theme in these discussions was a significant level of skepticism by ADEC and EPA regarding the likelihood of success in developing an approvable major source SO_2 precursor demonstration for the Fairbanks Serious area SIP given uncertainties about sulfate formation mechanisms under Fairbanks winter conditions. A summary of our findings is provided below.

A key element of a NAA SIP is a demonstration that planned emission reductions will result in attainment of the NAAQS in future years. ADEQ uses a computer model (CMAQ) to carry out this attainment demonstration. CMAQ is a photochemical dispersion model which simulates the transport, dispersion, and chemical transformation of emissions from all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors (NH_3, NO_x, VOC, SO_2) affecting the NAA. In order to complete its work within the available time and resources, ADEC is planning to use the same base year $PM_{2.5}$ episodes (Episode 1: 23 January – 11 February 2008 and Episode 2: 2 – 17 November 2008) and modeling approach for the serious NAA SIP attainment demonstration as were used in the moderate area SIP attainment demonstration. This is despite the limited amount of air quality monitoring data available during these episodes and the fact that air quality conditions in Fairbanks have changed significantly since 2008 due to emission reductions during the intervening years. Monitoring of $PM_{2.5}$ component species was conducted at the State Office Building (SOB) in downtown Fairbanks during the 2008 episodes. These data were used in the moderate area SIP to evaluate the ability of CMAQ to accurately reproduce the observed concentrations of $PM_{2.5}$ and its component species.

As shown in Table 1, comparisons of CMAQ predicted $PM_{2.5}$ with observed $PM_{2.5}$ showed over prediction of organic carbon (OC) and elemental carbon (EC) and under predictions of other PM species, including sulfate (SO_4). These over and underpredictions fortuitously balanced each other out, resulting in an apparently accurate prediction of $PM_{2.5}$ total mass. The prediction errors for individual PM species may be the result of an inaccurate emissions inventory or errors in CMAQ (or in the WRF model used to provide meteorological inputs to CMAQ). Of particular note is that CMAQ predicted very little in situ formation of sulfate from SO_2 emissions due to the lack of available oxidizing agents in the model. In technical documents prepared for the Fairbanks moderate area $PM_{2.5}$ SIP, ADEC concluded that CMAQ is under predicting the amount of secondary sulfate formation under the unique Fairbanks winter conditions due to some unknown SO_2 oxidation pathway.

Table 1. Comparison of observed and predicted PM species concentrations at State Office Building monitoring site (average over days with FRM measurements in both 2008 episodes).

Species	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)	Bias (%)
$PM_{2.5}$ (total)	36.1	35.7	-1%
OC	17.0	24.5	44%
EC	2.3	4.3	87%
SO_4	6.2	2.1	-66%
NO_3	1.6	1.3	-19%
NH_4	3.1	1.2	-61%
OTH	6.3	2.3	-63%

Source: *Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan.* D. Huff, Alaska Department of Environmental Conservation, 25 September 2014, in Reasonably Available Control Measure (RACM) Analysis (Appendix III.D.5.7 to the Fairbanks $PM_{2.5}$ Moderate State Implementation Plan).

In accordance with EPA's precursor demonstration guidelines, a successful precursor demonstration (in this case for SO_2) must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ NAAQS. More specifically, for a major source SO_2 precursor demonstration, the guidance requires a demonstration that eliminating SO_2 emission from all major sources within the NAA would not lower $PM_{2.5}$ concentrations by more than an insignificant amount (defined in the guidance as an amount not exceeding 1.5 $\mu g/m^3$).[1] If this "contribution-based" analysis indicates that the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 $\mu g/m^3$, then a "sensitivity-based" analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 – 70% would have only an insignificant impact on lowering $PM_{2.5}$ (also defined as an impact of less than 1.5 $\mu g/m^3$).
The primary obstacle to conducting a credible SO_2 precursor demonstration for Fairbanks cited by ADEC and EPA results from a combination of two facts:

1. the relatively large contribution of sulfate to total $PM_{2.5}$ mass (approximately 17-18% at the SOB) which results in an ammonium sulfate contribution to $PM_{2.5}$ design value[2] that is well in excess of the "insignificant" concentration threshold (1.5 $\mu g/m^3$) cited in EPA's precursor demonstration guidance document and which thus implicates the combined impact of major and minor SO_2 sources as significant contributors to peak $PM_{2.5}$ levels; and
2. the large under prediction of sulfate mass by CMAQ for the 2008 episodes (normalized mean bias of -66%)[3] which leads to the conclusion that the current modeling system (consisting of CMAQ and the emissions estimates and meteorological modeling results used as inputs to CMAQ) does not accurately characterize the contributions of SO_2 sources to the $PM_{2.5}$ design value.

In other words, SO_2 sources are observed to contribute significantly to $PM_{2.5}$ nonattainment and the current modeling system is not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2 sources. This makes it difficult to develop a precursor attainment

[1] While the 2016 guidance document recommends using 1.3 μg/m3, EPA recently updated and finalized the technical basis document used to set the recommended level and revised the significance threshold to 1.5 μg/m3.

[2] The design value is the pollutant concentration that is compared to the level of the NAAQS. For the 24-hour $PM_{2.5}$ NAAQS, the design value is the annual 98th percentile daily average concentration averaged over three years.

[3] "Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan", D. Huff 9/25/14, Table 1 (p. 125) in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7.

demonstration for major sources of SO_2 based on the current data and modeling system that otherwise would be considered sufficiently reliable to gain approval by EPA. We note that this also brings into question the reliability of a modeled attainment demonstration that includes SO_2 controls on major sources.

Despite the difficulties noted above with formulating an approvable major source SO_2 precursor demonstration, data analyses and modeling conducted for the Fairbanks moderate area SIP[4] provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment. We summarize these key results below:

- Analysis of CMAQ model results by UAF show almost no secondary SO_4 production during the modeled periods. Thus, nearly all of the modeled SO_4 is from primary SO_4 emissions.
- CMAQ underpredicted the SO_4 concentration at the SOB by an average of 3.22 μg/m^3 on days with FRM measurements during the 2008 winter episodes (the average observed SO_4 was 5.25 μg/m^3 while the average predicted SO_4 was 2.03 μg/m^3; note that these values are taken from Table 2 of *Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7* and differ slightly from the values in Table 1; we are still trying to determine the reason for these small differences).[5]
- ADEC concluded that there is likely sufficient excess NH_4 present under episode conditions so that reductions of secondary SO_4 would not lead to significant increases in other secondary species such as ammonium nitrate.[6]
- Both CMAQ point source SO_2 "zero out" runs - in which results from the base case CMAQ run are compared with a CMAQ run in which point source SO_2 emissions are reduced to zero - and CALPUFF model runs show that point sources contribute approximately 22% of the total modeled SO_2 from all sources at the SOB monitor with nearly all of the remaining SO_2 coming from heating oil combustion.[7] Note that the modeled point sources consist of the six major SO_2 sources in the nonattainment area.
- CMAQ zero out runs also show that 5% of primary SO_4 is from point sources. The CMAQ SO_4 prediction at SOB is 2.1 μg/m^3 (Table 1) so the modeled point source primary SO_4 contribution is no more than $0.05 * 2.1 = 0.1$ μg/m^3.
- Comparisons of total $PM_{2.5}$ mass concentration to the NAAQS are made using data from a Federal Reference Method (FRM) monitor. However, $PM_{2.5}$ species composition data are obtained from a SASS sampler. $PM_{2.5}$ measurements from these two different monitoring methods are not directly comparable due to various unavoidable sampling artifacts. In accordance with EPA guideline procedures, ADEC applied adjustments to the $PM_{2.5}$ species composition data from the SASS sampler at the SOB using the SANDWICH algorithm to more accurately reflect the composition of $PM_{2.5}$ samples collected by the FRM monitor. These adjustments account for differences in the amount of nitrate, ammonium, carbon, other primary $PM_{2.5}$ components (OPP), and particle bound water (PBW) captured by the two instruments.
- For purposes of developing the moderate area SIP, ADEC used the available ambient monitoring data processed through the SANDWICH algorithm to develop a "design day" $PM_{2.5}$ composition representative of the average composition of $PM_{2.5}$ during high wintertime $PM_{2.5}$ episodes. ADEC also calculated the applicable $PM_{2.5}$ "design value" which represents the $PM_{2.5}$ total mass concentration that is compared to the level of the NAAQS. For the moderate area SIP, the $PM_{2.5}$ design value at the

[4] https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-moderate-sip

[5] See Table 2, p. 129 in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7

[6] Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7, p. 131.

[7] Note that the CALPUFF point source modeling showed that on average only 0.1% of modeled point source SO_2 at SOB during the during Jan. 23rd – Feb 9th 2008 episode days was from the Flint Hills refinery, whereas 36% was from the four power plants and 64% from Ft. Wainwright.

SOB site was determined to be 44.7 µg/m^3. Applying the design day composition to the design value results in the design day $PM_{2.5}$ component concentrations shown in Figure 1.

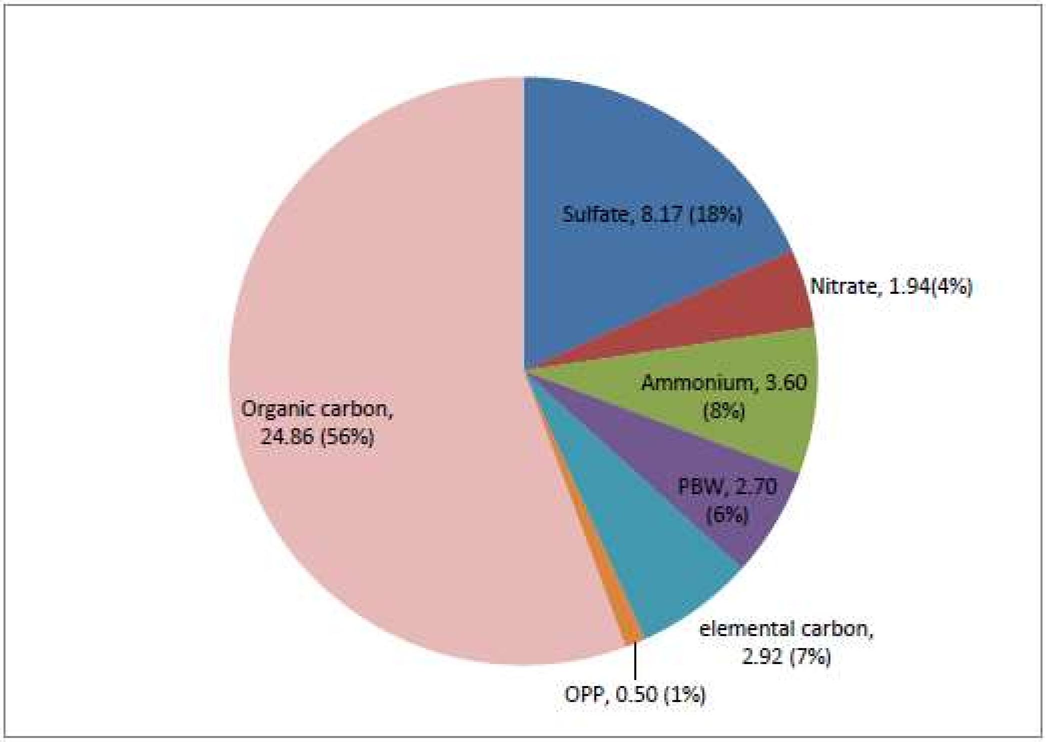

Figure 1. Design day $PM_{2.5}$ speciation at SOB used for the moderate area SIP (source: Appendix III.5.7, p. 122).

- For the design day, the 0.1 µg/m^3 primary sulfate contribution from point sources estimated from the CMAQ zero-out runs noted above scales up to 0.16 µg/m^3 (= 0.1 * 8.17/5.25) where 8.17 µg/m^3 is the amount of SO_4 on the design day and 5.25 µg/m^3 is the average observed amount of SO_4 for the modeled episodes.
- The design day PM composition shown in Figure 1 includes 8.17 µg/m^3 SO_4. The correspondingly scaled SO_4 that is unaccounted for in the CMAQ results is 3.22 * (8.17/5.25) = 5.01 µg/m^3. At one extreme, all of this "unexplained" SO_4 could be attributed to emissions from point sources (i.e., the major SO_2 sources). Perhaps more realistically, one could estimate that 22% of the unexplained SO_4 (0.22 * 5.01 = 1.1 µg/m^3) is from point sources, in keeping with the modeled 22% contribution of point sources to SO_2 noted above. Assuming all SO_4 is in the form of ammonium sulfate, this would be equivalent to a 1.1 * (132/96) = 1.51 µg/m^3 contribution to $PM_{2.5}$, where the factor 132/96 represents the molecular weight ratio of ammonium sulfate to sulfate. Adding to this the amount of particle bound water (PBW) associated with ammonium sulfate assumed in the SANDWICH estimate of FRM measurement (2/3 * 2.70 µg/m^3 = 1.80 µg/m^3 assumed to be associated with 8.17 µg/m^3 of SO_4 so 1.1 µg/m^3 * (1.80/8.17) = 0.24 µg/m^3 of PBW associated with the point source SO_4) results in a total point source ammonium sulfate with associated PBW contribution of 1.51 + 0.24 = 1.75 µg/m^3.
- The above simple "contribution-based" precursor demonstration result indicates that the major source SO_2 contribution is slightly above the "insignificant contribution" threshold (1.5 µg/m^3) cited

in EPA's Precursor Demonstration Guidance. However, the EPA guidance allows for a "sensitivity-based" precursor demonstration in which the reduction in $PM_{2.5}$ concentration resulting from a 30, 50, or 70% reduction in SO_2 emissions is compared to the 1.5 μg/m^3 significance threshold. Based on a linear extrapolation from the above analysis, a maximum 70% reduction in major source SO_2 emissions would be expected to produce a 1.23 μg/m^3 decrease in $PM_{2.5}$, which is below the 1.5 μg/m^3 significance threshold. In other words, the $PM_{2.5}$ design value is relatively insensitive to even a large (70%) reduction in major source SO_2 emissions.

Although the above result for a sensitivity-based SO_2 precursor demonstration is encouraging, it must be noted that the precursor demonstration guideline suggests that ADEC may still need to include consideration of the feasibility of major source SO_2 reduction measures in its SIP, even if the sensitivity-based demonstration produces a result below the significance threshold. This may be particularly important for Fairbanks given uncertainties about the amount of SO_4 actually contributed by the major sources.

It is also important to keep in mind that conditions have changed in Fairbanks since 2008 and the new Serious area SIP will use a base year of 2013 to represent "current conditions". Updated area source emissions will be modeled but episodic point source emissions will be based on the 2008 point source inventory. Modeling results are not yet available, so it is not possible to know how the above results might differ for the new base year.

Proposed BACT Alternative

November 19, 2018

Submitted by David Fish
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1.0 Introduction

The Fairbanks North Star Borough (FNSB) has levels of fine particulate matter ($PM_{2.5}$) that are above the health based National Ambient Air Quality Standard (NAAQS). In November 2009 the area was designated as a Moderate Nonattainment Area (NAA) based on monitoring data indicating the area did not meet the 2006 24-hour $PM_{2.5}$ standard. On April 28, 2017, the area was re-designated as a “Serious” NAA as a result of not attaining the $PM_{2.5}$ standard within 5-years from designation. As a result, the state is required to propose additional measures to bring the area into compliance within 10-years from designation (i.e., December 2019).

Once EPA re-classified the FNSB $PM_{2.5}$ nonattainment area to Serious, it triggered the requirement for stationary sources with over 70 tons per year (tpy) potential to emit (PTE) for $PM_{2.5}$ or its precursors (SO_2, NO_x, VOC, & NH_3) to conduct a Best Available Control Technology (BACT) analysis. Based on the Alaska Department of Environmental Conservation (ADEC) preliminary evaluations, sulfur dioxides are being evaluated for point source control measures under BACT. At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO2) control. Preliminary Determinations by ADEC suggest a capital cost to Aurora Energy, LLC (Aurora) for BACT compliance of $12,332,076 for an 80% removal efficiency using dry sorbent injection.

Aurora asserts that the proposed Best Available Control Technologies for sulfur dioxide emissions are not economically feasible. Confronted with this fact, ADEC and the EPA have asked Aurora to suggest an alternative to the ADEC proposed BACT. Within the context of this document Aurora is providing a proposal for alternative BACTs, all of which mitigate Aurora’s impact to the nonattainment area problem.

The alternative BACTs proposed by Aurora provide meaningful solutions in offsetting the largest contributing factor to the $PM_{2.5}$ problem in Fairbanks: home heating. The alternative BACTs being proposed by Aurora are more efficient from a dollar per ton of pollutant removed than the ADEC proposed BACT. Aurora strongly believes that these alternatives can have a more positive impact to the air quality issue than the ADEC proposed BACT. Before implementing these alternative BACTs, Aurora needs ADEC and EPA to agree that these alternative BACTs satisfy Aurora’s obligations for compliance with the NAA issue and that future controls to address $PM_{2.5}$ in the NAA will not be required.

Additionally, Aurora is making this alternative proposal based on the premise that ADEC and EPA will consider a precursor demonstration to determine the actual contribution of $PM_{2.5}$ by the point sources in the NAA. It has been stated repeatedly that the point sources are not the primary cause of the $PM_{2.5}$ problem. However there has never been a thorough analysis done to understand to what extent the point sources are or are not contributing to the problem. Should a precursor demonstration show that the point sources within the NAA are not major contributors to the $PM_{2.5}$ problem, all $PM_{2.5}$ compliance requirements imposed on the point sources shall be vacated. If however the precursor demonstration shows that the point sources are above the insignificance threshold, the alternative BACTs proposed by Aurora would satisfy the requirements for compliance within the NAA.

In closing, Aurora desires to be a part of the solution to reduce the $PM_{2.5}$ levels within the NAA. Aurora remains convinced that the ADEC proposed BACT is cost prohibitive and an inefficient use of funds. Instead Aurora is proposing alternative BACTs that directly help solve the PM2.5 problem. In proposing these alternatives, Aurora needs ADEC and the EPA to agree to continue to study the source of PM2.5

pollution as well as confirm that these alternative BACTs meet Aurora's compliance with the Clean Air Act for purposes of NAA attainment.

1.1 ADEC BACT Analysis

ADEC provided its review of a BACT analysis for Aurora which included an evaluation of technologies to mitigate emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form $PM_{2.5}$ in the atmosphere post combustion. The BACT analysis evaluated all available control options for equipment emitting the triggered pollutants and followed a process for selecting the best option based on feasibility, economics, energy, and other impacts. The results of the BACT analysis are reflected in Table 1.

Table 1: Department Economic Analysis for Technically Feasible NOx and SO_2 controls.

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 3,930,809.00	$ 957,728.00	$ 2,226.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 17,331,770.00	$ 2,787,995.00	$ 3,240.00
Dry Sorbent Injection (DSI)[2]	SO_2	$ 12,332,076.00	$ 4,284,104.00	$ 6,308.00
Spray Dry Absorber (SDA)[2]	SO_2	$ 60,270,115.00	$ 11,862,577.00	$ 15,525.00
Wet Scrubber (WS)[2]	SO_2	$ 65,957,875.00	$ 12,160,961.00	$ 14,469.00

1 - Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)

2 - Capital Recovery Factor = 0.1098 (7% interest rate for a 15 year equipment life)

1.2 Aurora BACT Analysis

The ADEC requested additional information concerning Aurora's BACT analysis in a letter dated September 13, 2018. One of the ADEC's request were that Aurora comment on the cost analysis spreadsheets developed by ADEC and provided with the Preliminary Draft SIP. Comments were made on the spreadsheets and submitted to the ADEC on November 1, 2018. Below (Table 2) are the results of Aurora's inputs considering EPA and ADEC's comments. Spreadsheets are included along with this proposal for review by the agencies. Several changes to the inputs are documented in the summary for the spreadsheet inputs (See Appendix A & B). In conjunction with the changes made to the spreadsheets, site-specific quote for SO_2 controls, namely Dry Sorbent Injection (DSI), was provided to the ADEC as requested and included as a parameter within the cost analysis spreadsheets for the referenced control technologies. The EPA is requiring that the cost analyses include a 30 year equipment life for the control technologies except SNCR which is evaluated for 20 year equipment life.

Table 2: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.1

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[2]	NOx	$ 6,208,948.00	$ 989,197.00	$ 3,107.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 2,921,054.00	$ 4,587.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,601,940.00	$ 8,423.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 51,115,267.00	$ 8,716,232.00	$ 12,408.00
Wet Scrubber (WS)[1,3]	SO_2	$ 56,318,290.00	$ 8,839,892.00	$ 11,440.00

1 – Capital Recovery Factor = 0.0669 (5.25% interest rate for a 30 year equipment life) [EPA requirement per comments]
2 – Capital Recovery Factor = 0.0820 (5.25% interest rate for a 20 year equipment life) [EPA requirement per comments]
3 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

Table 3 reflects another iteration (V.2) of Aurora's changes to the ADEC's spreadsheets. The results in Table 3 consider a lower emission rate for both SO_2 and NO_x based on 2011 source testing information and/or additional information. The SO_2 emission rate assumed by the state and Aurora has been 0.39 lbs/MMBtu. The coal analysis for feed coal during the test showed elevated sulfur content (0.18%) in comparison to the 5-year weighted average sulfur content from 2013-2017 (0.14 %). Using a conservative conversion from sulfur content (0.14%) to sulfur dioxide, the 5-year weighted average SO_2 emission rate would be 0.36 lbs/MMBtu. This conservative emission rate was used in the calculations to derive the cost effectiveness values in Table 2. The sulfur content during the source test conducted in 2011 (0.18%) when converted to a heat input emission rate considering total conversion of sulfur to SO_2 yields an emission factor of 0.48 lbs/MMBtu. The actual tested emission rate was 0.40 lbs/MMBtu. The emission rate for SO_2 was 83% of the maximum potential. This suggests there is 17% capture of sulfur compounds in the ash. As such, the emission rate derived and used in Table 3, considers a 17% capture of sulfur in the ash. The conversion of sulfur to SO_2 based on the 5-year weighted average sulfur content in coal and a 17% capture rate yields 0.30 lbs/MMBtu (0.36 lbs/MMBtu X 0.834 = 0.30 lbs/MMBtu). The results in Table 3 account for the current sulfur content in coal and the rate adjustment for sulfur capture fraction from the process based on a source test conducted in 2011.

Also accounted for in Table 3 is a more realistic equipment life expectancy for the facility and control equipment. It is not reasonable to consider a 30 year and 20 year life expectancy for the control equipment and the boilers. Considering the age of the Chena Power Plant, Units 1-3 are 50,000 lb/hr boilers that were installed in the early 1950s, and Unit 5 is a 200,000 lb/hr boiler which was installed in 1970. Units 1-3 are already +65 years and Unit 5 is +45 years old. A 30 year horizon should not be applicable to the Chena Power Plant. A 15 year equipment life is considered in the following cost effectiveness analysis (Table 3).

Table 3: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.2

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 6,208,948.00	$ 1,088,694.00	$ 3,419.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 3,721,132.00	$ 5,844.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,914,480.00	$ 10,785.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 50,880,540.00	$ 10,084,456.00	$ 17,213.00
Wet Scrubber (WS)[1,2]	SO_2	$ 56,318,290.00	$ 10,314,589.00	$ 16,005.00

1 – Capital Recovery Factor = 0.0980 (5.25% interest rate for a 15 year equipment life)
2 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

2.0 Economic Infeasibility

The BACT review process as outlined by EPA includes five-step approach to determine the best control option. The economic feasibility of potential measures are addressed under Step 4 of the review process. Since there is no cost threshold for economic feasibility for controls within a serious nonattainment area, a source has to make the assertion to the regulatory agencies in order for economic infeasibility to be considered. Aurora's BACT results, as illustrated in Table 3, show that the least expensive SO_2 control technology is a $20 million dollar investment and the cost effectiveness value is above $10,000/ton of SO_2 removed.

Therefore, per the fine particulate implementation guidance, if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology demonstrated to be economically feasible, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators to the extent applicable:[1]

1. Fixed and variable production costs;
2. Product supply and demand elasticity;
3. Product prices (cost absorption vs. cost pass-through);
4. Expected costs incurred by competitors;
5. Company Profits;
6. Employment costs;
7. Other costs (e.g., for BACM implemented by public sector entities).

At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO_2) control. ADEC's preliminary determination suggests Aurora invest $12,332,076 for DSI technology to remove 80% of the SO_2 emissions from the Chena Power Plant. ADEC estimates that annualized costs for the application would be $4,284,104. ADEC's projected capital cost for retrofit SO_2 control technology is just above half of the costs of a +50/-30 design (e.g., capital cost $20,682,000) which was recently submitted to the ADEC. Even if the lower cost for controls estimated by the ADEC were valid, it is not economically feasible and therefore should not be required. Further, ADEC does not know whether the installation of DSI or any control technology on stationary sources will have a significant impact on the overall air quality in the non-attainment area.

Aurora has one electric customer and approximately 200 district heating customers. Income from power production is from wholesale electric sales to the local electrical cooperative, Golden Valley Electrical Association (GVEA). Aurora has a long term contract with GVEA which would be difficult to renegotiate for necessary price increases to accommodate additional control technologies. Pass-through cost opportunities for Aurora's district heating are not viable. The necessary product price increases to cover additional costs of the proposed control technology would price Aurora out of the market for both heat and power. The result would be higher electric and heat costs, coupled with an increase in $PM_{2.5}$ pollution due to the introduction of ground-level emissions from oil and/or gas fired furnaces and boilers that would be installed to replace uneconomic district heat. As Aurora customers switch to less expensive fossil fuels – or yet even less expensive wood – the resulting burden on Aurora's remaining customers will increase, causing more and more of them to switch, resulting in a continuous increase in particulate emissions in the Fairbanks core, and in a death spiral for Aurora as an economically viable business. Within this section, Aurora will address the financial indicators applicable to demonstrate the economic infeasibility of installing and operating ADEC's proposed control technology.

1. Production Costs

Aurora's five year operating costs for electric and district heating (RCA) are provided below in Table 4. Operating costs consist of operations expense, maintenance expense, administrative expenses, and depreciation expense. The net operating costs for power generation was $0.08/kW in 2017 (Table 4). The

[1] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085.

margin for income is small as reflected in Table 6. District heating operating costs exceed income generated resulting in a net loss over the past 5 years (Table 6). [2]

Table 4: Aurora Energy Operating Costs

Year	Electrical Total	Net kWh	$/kWh	District heating Total	Net MMBtu	$/MMBtu
2017	$13,795,480	181,113,600	$0.08	$4,658,655	262,189	$17.77
2016	$13,707,259	189,093,610	$0.07	$5,285,399	249,151	$21.21
2015	$12,582,952	194,083,220	$0.06	$5,395,212	267,686	$20.16
2014	$12,250,548	184,058,400	$0.07	$5,648,209	273,089	$20.68
2013	$10,833,349	181,569,600	$0.06	$5,387,853	274,139	$19.65
Average	***$12,633,918***	***185,983,686***	***$0.07***	***$5,275,066***	***265,251***	***$19.89***

2. Supply and Demand Elasticity

The issue of supply and demand elasticity is addressed in more detail within the context of the following sections. The cost of control technologies cannot be absorbed by Aurora under the current pricing to consumers for district heating and power. Aurora has no alternative but to pass those costs to its customers. Those customers, in turn, would have no choice but to go elsewhere for their heat and power, as Aurora would no longer be competitive with other options. This would be the beginning of a death spiral for Aurora as a business, and the beginning of an increase in lower level emissions in the Fairbanks core as more and more buildings switch to oil or gas for heat.

3. Product prices (cost absorption vs cost pass-through)

Aurora's current product prices are competitive with other power suppliers and heating sources. Aurora's heat business is generally regulated by the Regulatory Commission of Alaska (RCA). District heating prices are set based on Aurora's cost to produce the heat. At the same time, many district heat customers are able to switch to alternative sources of heat, such as oil, gas or wood; therefore, Aurora has a powerful incentive to maintain district heating prices competitive with other heating options. Likewise, GVEA maintains several contracts with various power producers including Aurora. GVEA's portfolio includes power generated with natural gas, hydroelectric gradient, wind, solar, coal, and oil. Aurora's contract with GVEA ensures Aurora's power pricing is competitive and marketable.

District Heating

District heating prices cannot absorb the pass through costs of control technology. Aurora's district heating customer base is approximately 200 including mostly commercial and some residential customers. District steam heating rates are set with oversight by the RCA and do not vary. Hot water district heating prices differ depending on consumers' annual heating needs. The hot water district heating rates are adjusted throughout the year to be competitive with other sources of heat.

Absorbing full or partial costs for upgrades or control technologies is not feasible through district heating rate adjustments. The price adjustment necessary to compensate for the current average annual net loss from district heating (Table 6) would be an increase of $3.71/MMBtu representing a 20% increase in heating costs. A 20% increase in district heat prices per unit energy (MMBtu) is not marketable. The potential is a loss of revenue from customers switching to alternative forms of heat which would make

[2] Based on RCA annual filing from 2013-2017.

district heating even less sustainable and exacerbate air quality due to an increase in ground level emissions.

Electric Generation

Aurora's power pricing cannot absorb the pass through cost of control technologies without revising the current contract and becoming less marketable. Aurora sells its power at wholesale price to GVEA, its sole electric customer. Aurora has averaged 186,000 MWh in net sales annually. Pass through of any additional incurred cost would have to be negotiated with GVEA, and would cause an increase in power costs to all customers in GVEA's service area.

Product Pricing for GVEA including Control Technology Costs

ADEC indicates that SO_2 controls are being considered for BACT or Most Stringent Measures (MSM) at this time.[3] ADEC's estimate of the capital investment of the preferred control technology for Aurora is estimated to be $12,332,076 and the annualized cost is estimated to be $4,284,104. The requirement is that BACT must be installed within 4 years of reclassification of an area from a moderate to a serious nonattainment area.[4] The Fairbanks North Star Borough nonattainment area designation change from "Moderate" to "Serious" was effective June 9, 2017.[5] Since the area is now identified as serious, BACT control would have to be in place by June of 2021. Funds for the capital investment would need to be arranged by 2019 to allow for construction and installation of the control equipment. The power purchase agreement with GVEA would need to be renegotiated prior to committing to construction.

Assuming electrical sales would correspond to the 5-year average (185,984 MWh), the weighted average price per MWh at the Chena Power Plant (CPP) would be $85.51.[6] When the annualized cost of operating the preferred control technology is included, the price of power from the CPP increases to $108.55/MWh; a 27% increase in price of power. The average total electric power consumption of sulfur control on Healy Unit #2 is 550.5 kW.[7] Assuming a comparable station service use, SO_2 control on the Chena Power Plant could require an additional 2.6% for station service load.

The SO_2 control technologies being considered (DSI) require the addition of lime, limestone, or sodium bicarbonate to the gas path prior to the baghouse. The amount of unreacted sorbent added to the process could alter the leaching characteristics of metals from coal ash. Recent testing of coal ash from coal blended with 2% by weight limestone, demonstrated elevated metals leaching from coal ash at various pH. Metals leaching in excess of water quality standards could require Aurora to incur additional disposal costs for coal ash. Aurora would either have to build a coal ash landfill, or take the coal ash to the municipal landfill at a cost to Aurora of $90/ton.[8] If additional costs were incurred by Aurora for disposing 20,000 tons of coal ash, then the price per MWh would need to increase to $118.60; which represents a 39% increase in the price of power.

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[3] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[4] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016.
[5] Federal Register, Vol. 82, No.89, Wednesday May 10, 2017.
[6] 2013 Contract Pricing for 2020: $79.37/MWh (≤150,000 MWh) + $112.12/MWh (>150,000 MWh).
[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.
[8] FNSB. 2014. Interior AK Coal Ash. Pg. 42

Table 5: $/kWh Wholesale Pricing for GVEA including Control Technology Costs

	Average kWh/year (2013-2017)	No Controls	SO2 - DSI	SO2 - SDA	SO2 - WS
Annual BACT Operating Cost		$ -	$4,284,104	$11,862,577	$12,160,961
2020 ($/kWh)	185,983,686	$ 0.09	$ 0.11	$ 0.15	$ 0.15
2020 ($/kWh) -2.5% station load (BACT)	181,334,094	$ 0.08	$ 0.11	$ 0.15	$ 0.15
Coal Ash Disposal - Borough Landfill[1]		$ -	$ 0.12	$ 0.16	$ 0.16

1 - Borough Landfill disposal cost based on 20,000 tons of ash; $90/ton (FNSB. 2014). Interior AK Coal Ash. Pg 42.

Aurora's price of power is in competition with other power producers. If the price of power exceeds that of the competition, Aurora would not be as competitive in the energy market. Currently, GVEA will take as much power as Aurora can produce; however, it is likely that GVEA would reduce the amount of power accepted from Aurora if product prices increase above those of the competition.

4. Expected costs incurred by competitors

The FNSB nonattainment area impacts stationary sources within the area. Aurora's main competitors are power producers outside of the nonattainment area. Aurora's competition will not be required to consider BACT or MSM as a new requirement of a nonattainment area. This puts Aurora at a serious economic disadvantage. It is the only private for-profit power producer in the state being subjected to the $PM_{2.5}$ nonattainment area BACT requirements. Table 5 illustrates the price of wholesale power in $/kWh from Aurora. The price of power with controls is $0.11/kWh. When additional disposal requirements are considered as a result of the use of the control technology, the price of Aurora's wholesale power to GVEA is $0.12/kWh.

Aurora's competition for power sales is primarily natural gas generated power; including Anchorage Municipal Light and Power (AMLP), Matanuska Electric Association, Inc. (MEA), and Chugach Electric Association (CEA). Aurora is also in competition with GVEA's fleet including the coal facilities (Healy #1 and Healy #2). The expected increase in price of Aurora's power due to BACT will make its power less marketable. At $0.12/kWh, the price of Aurora's power to GVEA would exceed AMLP ($0.09/kWh), Healy #1 ($0.10/kWh), MEA ($0.10/kWh), and CEA ($0.11/kWh) based on GVEA's cost of power report in 2017[9]. Aurora currently provides 14% of GVEA's power requirements. At current prices, Aurora's power is competitive. An increase in the price of power to $0.11/kWh or $0.12/kWh would likely change that perspective.

5. Company Profits

Net income (loss) for Aurora over the past five years are not sufficient to absorb annual control technology costs for any of the control technologies proposed. Table 6 below includes the net income (loss) from district heating, electrical generation and the combined company income (loss) for years 2013

[9] 2017 GVEA Annual Report to the RCA.

through 2017. Net income (loss) include income generated from district heat and power sales minus the operating costs as presented in Table 2 and include nonutility income, interest income, miscellaneous amortizations, and interest expenses.

Table 6: Aurora Energy, LLC – 5 Year Net Income (Losses)

Year	Electric	District Heating	Net Income (loss)
2017	$ 801,037.00	$ (377,585.00)	$ 423,452.00
2016	$ 419,092.50	$ (1,808,914.00)	$ (1,389,821.50)
2015	$ 1,094,599.25	$ (1,059,348.00)	$ 35,251.25
2014	$ 321,876.05	$ (892,950.00)	$ (571,073.95)
2013	$ 420,072.77	$ (775,432.00)	$ (355,359.23)
Average	***$ 611,335.51***	***$ (982,845.80)***	***$ (371,510.29)***

The annual cost to operate the preferred technology is $4,284,104 (Table 1 & 4); the average 5-year net income (loss) for Aurora is ($371,510) [Table 6]. Conclusively, Aurora is not able to absorb the cost of additional control technologies.

The only alternative for Aurora to address annual operating expenses for any proposed control technologies would be to attempt to renegotiate the power contract to raise the price of power to GVEA. However, the rate adjustment would increase the price of Aurora's power to the extent that it would be less competitive.

6. Employment Cost

The state's calculations for annual operation costs of the proposed technologies include labor cost increases. The increases vary depending on the type of control technology. As a part of the state's analysis for SO_2 controls, annualized cost increases include the projection of additional labor for operation, maintenance, and administration.

7. Other Costs

No additional costs were considered.

ADEC has not shown that Aurora's, nor other stationary source's, SO_2 emissions are a significant contributor to the nonattainment area problem. ADEC does not know whether installation of BACT or MSM on stationary sources will significantly mitigate the impact of SO_2 on particulate concentration. Aurora cannot afford the control measure or technology that has been selected by the ADEC in the preliminary BACT analyses. The basis for this determination is that Aurora has consistently shown insufficient income to absorb the cost of the control technologies. Alternatively, increasing the price of power or heat to accommodate the cost of control technology will price Aurora's products out of the market. Any increase in district heating prices would make alternative sources of heat more attractive to consumers. The result would be a loss in business from customers switching to alternate sources of heat. This change in heating source could exacerbate pollution emissions at the ground level due to customers' use of distributed home heating alternatives. Aurora's district heating displaces the emissions from the equivalent of 2 – 2.5 million gallons of heating oil. The current power purchase agreement with GVEA allows Aurora's power to be competitive with other power sellers. The cost of additional control technology would have to be negotiated with Aurora's one customer based on its power purchase agreement and make Aurora's power prices less competitive; and subsequently, less sustainable.

3.0 Proposed Alternative BACT – District Heating

Aurora is sympathetic to the requirements of the Serious Nonattainment Area and believe that a reasonable alternative exists within the framework of what is economically feasible. As previously discussed, Aurora asserts that imposing retrofit controls, as proposed by ADEC, on its older boilers in the next four years is economically infeasible and could have negative impacts on the goals of the community to achieve attainment with the $PM_{2.5}$ standard. As such, Aurora has developed a list of mitigating measures that are more economically sustainable and will have a direct impact on the community with respect to achieving attainment with the $PM_{2.5}$ standard. Included as alternatives are the expansion of district heating, a wood drying kiln, and the potential use of biomass.

3.1 District Heating

Aurora is proposing that past district heat expansions as well as future district heating projects be considered as BACT for the Chena Power Plant. As it stands, Aurora's district heating displaces about 42 tons of SO_2 and 2 tons of particulates annually. District heating is referenced in both the Moderate Area State Implementation Plan (SIP)[10] and the Preliminary Serious Area SIP[11] as a Pollution Control Measure for the FNSB NAA. As stated in the Moderate Area SIP, "An increase in the coverage of the district heating systems would therefore result in a decrease in measured $PM_{2.5}$ concentrations". Based on modeling results, the $PM_{2.5}$ concentration attributed to Aurora during an episode in 2008 was 0.02 µg/m^3 and the SO_2 concentration at ground level from Aurora represents 0.75 µg/m^3 (See Table 7).[12] The implication of the small pollutant contribution from Aurora at ground level is that taller stacks decrease the impact from emissions at ground level. The amount of pollutant loading at ground level within the nonattainment area is mitigated by district heating through the removal of ground level source emissions and vertically displacing them. An added benefit to increasing district heat coverage is an increase in efficiency at the plant. The plant is generally base loaded and driven to operate at a maximum capacity; there is moderate room for growth, but realistically, the plant is nearing its maximum capacity. The plant could accommodate, roughly, an additional 100 MMBtu/hour of heating capacity while still being able to provide a modest amount of electricity.

Table 7: Summary of Six Major Fairbanks Point Source Plumes from CALPUFF for the Episode (Jan.23rd to Feb. 9th, 2008) Average Surface Concentrations at the State Office Building of PM2.5 and SO2 in ug/m3.

Power Plant	Episode average SO_2 (µg/m^3)	Episode average $PM_{2.5}$ (µg/m^3)
UAF- 316	2.75	0.16
Aurora- 315	0.75	0.02
Zehnder-109	0.48	0.19
Flint Hills-071	0.016	0.38
GVEA NP-110	3.8	1.45
Ft. WW- 1121	14	1.6
Total surface concentration	21.8	3.8

In order to quantify the impact district heating has on the nonattainment area, Aurora evaluates the potential use of fuel oil based on

[10] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 42.
[11] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[12] ADEC. 2014. Moderate Area State Implementation Plan. Section III.D.5.8-11.

a conversion from the heating load compensated by the plant for district heating. A fuel oil heating value of 137,000 btu/gal and an assumed efficiency of 85% for heating appliances are used to determine the quantity of heating oil equivalent to the district heating load. Since SO_2 and $PM_{2.5}$ are the pollutants of most concern, Aurora is using emission rates for fuel oil using EPA's emission inventory warehouse, AP-42. Using the value of 2566 ppm sulfur in heating oil[13], an emission rate of 36.92 lbs/10^3 gallons (2.64x10^{-1} lbs/MMBtu) for SO_2 emissions and 0.4 lbs/10^3 gallons (2.86 x10^{-3} lbs/MMBtu) for filterable or direct $PM_{2.5}$ and 1.3 lbs/10^3 gallons (9.29 x10^{-3} lbs/MMBtu) for condensable $PM_{2.5}$ are derived. Using these emission rates, Aurora can evaluate the impact of district heating on the removal of SO_2 and $PM_{2.5}$ from the nonattainment area.

As part of a further analysis, the SO_2 is converted to $PM_{2.5}$ by using an ADEC derived method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration from various sources. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Through the use of a dispersion model, CALPUFF, ADEC determined that 22% of modeled SO_2 concentration are from point sources at ground level, 78% are from central oil, and <1% from mobile sources. Using this information and the ADEC's methodology (based on 'scenario 2'), a ratio of 5.5 tons SO2 emissions from major sources is estimated to form 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate [8.38 TPD/(1.1 µg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$.[14] Based on the same methodology, the ratio of SO_2 from fuel oil (78% of modeled concentration) to particulates is 0.8 tons of fuel oil SO_2 emissions to 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate [4.12 TPD[15]/(3.9 µg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. To summarize this information and that in Table 8, wood smoke produces 18 times more $PM_{2.5}$ than the SO_2 from point sources and 2.6 times more $PM_{2.5}$ than fuel oil.

Table 8: Source pollutant emission and equivalent contribution in µg/m^3 of $PM_{2.5}$.

Pollutant	Point Sources (SO_2)	Fuel Oil (SO_2)	Wood Smoke
Emissions (tons)	5.5	0.8	0.3
$PM_{2.5}$ Equivalent Concentration (µg/m^3)	1	1	1

3.2 District Heat Expansion

District heating from Aurora mitigates emissions from ground level sources. The 5-year average (2013-2017) heating value of Aurora's district heat supply is 265,251 mmbtu/year. That is equivalent to about 2.3 million gallons of heating oil per year; assuming a heating value of 137,000 btu/gal and an 85% efficiency for an oil fired furnace. Using these values, district heat displaces about 42 tons of SO_2 from ground level emissions per year and 2 tons of $PM_{2.5}$ in the down town area. Since 2008, Aurora has added district heating equivalent to 243,000 gallons of fuel oil per year. The impact of the addition is equivalent to the removal of 3510 lbs of wood smoke per year based on SO_2 reduction from fuel oil [4.5 TPY SO_2 fuel oil/0.77 tons SO2 fuel oil/1 µg/m^3 x 0.3 tons wood smoke/1 µg/m^3 x 2000 lbs/ton]. District heating records show that 67% of heating use is between November – March (151 days). The loading that

[13] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 102.
[14] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.
[15] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 27.

was mitigated since 2008 is approximately 16 lbs/day of wood smoke equivalence during the winter months.

Aurora has the mechanical potential to expand district heating another 100 mmbtu/hr of additional heating. The equivalent SO_2 removal potential would be about 24 tons per year based on the displacement of 1.3 million gallons of heating oil No.2 (fuel oil S% = 0.26).

3.3 District Heating Economics

Installation of district heating can be costly. The evaluation of DH as a control technology for the plant is difficult to assess a cost/ton comparison. Ideally, the expansion cost would be mitigated by revenue generated from the use of district heating. The business model for district heating would justify the expansion; the added benefit would be the reduction in pollutants emissions from ground level sources, and a decrease in the output based emission rate. In general, efficiency gains at the plant is a sustainable practice with the benefit of reducing pollutant emissions at ground level.

3.4 Output Based Emission

District heat expansion has the added benefit of making the plant more efficient. A method of illustrating efficiency gains with respect to pollutant emissions is in the derivation of an output based emission rate. The output based emission rate for SO_2 at the plant is approximately 4.6 lbs/MW of energy output. The emission rate is based on a conservative calculation using the 5-year weighted average coal sulfur content and converting all of it to SO_2. The denominator consists of net power and net district heat sales in MW. When the maximum output of district heating is added to the denominator, the emission rate is reduced to 3.4 lbs/MW. This represents a 27% reduction in the emission rate per energy output.

The output based emission rate can be used to show efficiency gains with respect to pollutant emissions. Efficiency gains through the use of central heat and power facilities clearly demonstrate the advantages of minimize emission increases while maximizing energy output.

4.0 Proposed Alternative BACT - Firewood Drying Kiln

Couched within the benefits of district heating, Aurora is proposing an alternative to address its potential formation of fine particulate matter ($PM_{2.5}$) from sulfur dioxide. According to a 2008 report by the Northeast States for Coordinated Air Use Management (NESCAUM), for every 10 percentage point increase in the moisture content of wood, the $PM_{2.5}$ emissions increase by 65% to 167%. The increase in emissions is due to increased amount of wood needed to evaporate the extra moisture and poor combustion conditions leading to reduced heat transfer efficiency. Wood fuel use may double if wet wood were burned as opposed to dry wood.[16] Aurora is proposing to develop and operate a firewood drying kiln using district heat from the Aurora plant to help mitigate the use of wet wood. The general idea is that, along with district heat conversions, Aurora would offset its potential $PM_{2.5}$ formation by providing dry wood to the community from a kiln. The kiln would require 3.5 mmbtu/hour of thermal loading from district heating. The initial moisture content in the wood is assumed to be around 50%; the kiln would evaporate 35% of the moisture to a wood moisture content of 15% or less. By conditioning solid fuel (fire wood) to be used in homes, district heating is effectively expanded without the cost of installation.

[16] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 22.

4.1 Equivalent Emissions

The state has derived a method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Based on 22% of modeled SO_2 concentration from point sources at ground level, a ratio of 5.5 tons SO_2 emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$.[17] Using the fore mentioned conversions, Aurora estimated the power plants SO_2 emissions equivalent to wood smoke emissions. Based on an emission rate at Aurora of 608.3 tons/year of SO_2 (1.67 tpd), the wood smoke emission equivalent is 181 lbs/day [1.67 TPD/ (5.5 tons SO_2 from major sources/1 µg/m^3) x 0.3 tons of wood smoke/1 µg/m^3 x 2000 lbs/ton]. The equivalent annual wood smoke emission to 608.3 tons of SO_2 emission is proposed to be mitigated through drying wood by reducing 35% moisture from cord wood.

Table 9: SO2 Conversion to Wood Smoke Equivalent Emission

Source of Emissions	SO_2 Emissions (tpd)	$SO_2/PM_{2.5}$ (tpd)/(µg/m^3)	Wood Smoke/$PM_{2.5}$ (tpd)/(µg/m^3)	Wood Smoke Equivalent (lbs/day)
Aurora Energy	1.67	5.5	0.3	181
Displaced Heating Oil Use - DH	0.01	0.8	0.3	10

The emission reduction for $PM_{2.5}$ in lbs/MMBtu was derived using the ADEC's referenced information within the Appendices of the Moderate Area State Implementation Plan (See Tables 10 & 11). The average emission rate for wood burning devices at 50% moisture (1.14 lbs/MMBtu) was subtracted from the average emission rate for wood burning devices at 15% moisture (0.67 lbs/MMBtu). The equivalent amount of cords needed to account for 100% of Aurora's annual SO_2 emissions is 8,495 cords per year.

Table 10: Emission Factors based on wood moisture content

Wood Burning Devices	EF PM2.5 lbs/ton[1]	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu
Moisture content (%)		0		15		50	
non-EPA certified Wood Stoves	11.6	8,119	7.14E-01	6,901	8.40E-01	4,060	1.43E+00
EPA Wood stove non-catalytic	7.57	8,119	4.66E-01	6,901	5.48E-01	4,060	9.32E-01
EPA Wood stove catalytic	8.4	8,119	5.17E-01	6,901	6.09E-01	4,060	1.03E+00
Hydronic Heater weighted 80/20 (OWB unqualified/OWB-Ph2)	9.43	8,119	5.81E-01	6,901	6.83E-01	4,060	1.16E+00
Average emission factor	9.25	8,119	5.70E-01	6,901	6.70E-01	4,060	1.14E+00
Note: 1 - Appendix III.D.5.6-105, Table 5.6-40; 2 - Appendix III.D.5.6-86, Table 5.6-31							

[17] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

Table 11: Calculation to determine how much kiln dried wood is necessary to mitigate AE's SO_2 emissions.

PM 2.5 Daily Emissions Reduction [Scenario 2] (lbs/day)	181
PM 2.5 Annual Emissions Reduction (lbs/year)	66,003
Spruce weight at 20% moisture	2,550
Dry Wood (%) moisture	15
Wet Wood (%) moisture	50
Emission Diff. wet vs. dry (lbs/MMBtu)	4.69E-01
Daily Wood processing minimum (MMBtu/year)	140,695
Cords per year	8,495
cords/load	42
Loads per year	202

4.2 Firewood Kiln Economics

The capital cost and annualized cost of the kiln is much less than that of the other BACT alternatives. The cost effectiveness is determined by a $/Cost ratio based on drying wood at a maximum potential of 8,495 cords of wood to reduce, effectively, 608.3 tons per year of SO_2-equivalent emission. The annualized cost is used to derive the cost effectiveness ratio of $980 per ton of pollutant removed.

Table 12: Cost Effectiveness of Kiln

Control Technology	PM 2.5 Reduction (tpy)	Equivalent SO2 Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Cost ($/year)	Cost Effectiveness ($/ton SO_2)
Wood Kiln	32.5	608.3	$ 1,500,000	$ 736,078	$ 980

Unlike a traditional BACT approach, the effective emission reduction is hinged on the marketability of dry wood. Aurora plans to market the kiln dried wood as a benefit from a performance and air quality standpoint. The Fairbanks Northstar Borough, ADEC and EPA all have an important role in enforcing the use of dry wood for home heating the NAA.

5.0 Proposed Alternative BACT - Biomass Co-Firing

Aurora's boilers are subject to 40 CFR 63 subpart JJJJJJ. Under the rule, the Chena Power Plant (CPP) boiler units are classified as coal-fired boilers. The definition of coal-fired boiler subcategory extends to coal boilers that burn up to 15% biomass on a total fuel annual heat input basis. This flexibility in definition would allow Aurora to burn up to 15% biomass and still retain its classification as a coal-fired boiler. Aurora has been involved in a projects with Alaska Center for Energy and Power (ACEP) and the US Forestry Service using biomass (wood chips and refuse) as a substitute for coal. The projects did not demonstrate much of a change to the current operations; however, the material used had a significant amount of moisture (40%) and was not uniform. Sizing of the material was an issue and created problems. Biomass refuse and chips were not appropriately sized and created issues with material feeding through the auxiliary coal feed system. Also, due to density differences, material segregation within the bunkers occurred; wood chips tended to be pushed to the top of the coal. Ultimately, the lessons learned from the project were that with the right material sizing and processing, biomass could be used in the boilers to

help increase efficiency. As noted by operators during the project, the biomass burned off quickly leaving holes within the coal bed which allowed for air pockets which qualitatively made coal combustion more effective. The theory is that air voids left after the biomass was burned off facilitated greater air-to-fuel contact. Also, the rapid burning of the biomass may have increased the heat of the coal bed which helped coal combustion. Although this theory has not been vetted though rigorous research, the potential benefits of using biomass within the process may be substantial. At the very least, biomass has very little sulfur and could be a measure to mitigate the emissions of SO_2 from the plant.

The material used during the biomass project at Aurora was unprocessed and, consequently, not uniform. If the biomass material was processed and met some consistency standards there could be a significant measurable gain in efficiency. As such, processed biomass in the form of industrial grade pellets can provide a consistent sizing which would be compatible with the sizing of the stoker coal used at the Chena Power Plant (CPP). The benefit of using an industrial grade pellet is that the anticipated heat content of the pellets are assumed to be upwards of 8300 btu/lb, the moisture content is near 0%, and there is very little sulfur in the fuel. The cons of using an industrial grade biomass pellet is the cost of the fuel which could be as high as $295/ton. At this cost, the use of biomass is not economical. Furthermore, Aurora has not determined whether or not enough raw timber supply is available around the Fairbanks area to accommodate a consistent 15% blend rate. However, if waste biomass material, such as sawdust or bark, from local wood sellers were processed into pellets the raw material could be acquired at a low cost.

5.1 Biomass Economics

Biomass pellets, due to their lack of sulfur, could be used as mitigation for SO_2 emissions. As stated above, the negative aspect of pellets is in the cost and potential lack of access to raw material supply. In order to derive a price point for pellets that would be acceptable as a control technology, a cost effectiveness value of $3,125/ton SO_2 removed is used as a reference. This is a conservative estimate derived by the state in the moderate area SIP.[18] If the 5-year average revenue generated by the plant is divided by the 5-year average coal use we get a value of $79.09 revenue/ton of coal. Pellets have a higher btu/lb content than the coal and pellets have no moisture. To account for this discrepancy, coal heating value is considered after the evaporation of moisture. The energy needed to vaporize free moisture (h_{vap} =1049 btu/lb @ 77F) is multiplied by the moisture fraction of coal to derive the heat content of the coal at 0% moisture. When comparing the wood pellets to coal, the 5-year average heat content (7623 btu/lb) and moisture (29%) is considered. The heating value of coal without moisture is 7304 btu/lb (7623 btu/lb –

Table 13: Biomass and Coal Fuel Revenue/MMBtu

hhv pellets btu/lb	8,300
hhv pellets mmbtu/ton	16.6
hhv coal btu/lb	7,613.05
coal moisture	29%
heat of vaporization of water @ 77F btu/lb	1,049.70
coal btu/lb -vaporized free water	7,304
coal mmbtu/ton -vaporized free water	14.6
pellet coal equivalent	1.14
revenue/ton of coal	$ 79.09
revenue/mmbtu of coal	$ 5.41
revenue/mmbtu of pellets	$ 4.76

[18] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

1049.7*29/100). Pellets would have a heating content of 8300 btu/lb and no moisture. If the price of the pellets were $84/ton, the cost effectiveness value would be $3,093.04/ton SO_2 removed.

The emission reduction potential using pellets at 15% total fuel loading is 91.24 tons of $S0_2$ per year. Aurora is actively pursuing this concept; however, running the boiler with 15% biomass has not been tested and a supply of industrial wood pellets at the preferred price has not been identified nor has the availability of the raw material supply been verified.

Table 14: Biomass Cost Effectiveness Calculation

capital investment (hopper modification to auxillary coal feed system)	$300,000.00
loan period (years)	$5.00
interest rate (%)	8%
monthly loan amount	$6,082.92
Annual loan amount	$72,995.04
Burden for 0.5 man equivalent (2016)	$65,520
5-year avg Annual Coal (tons)	221,758.29
5-year avg coal sulfur (%)	0.14%
potential max SO2 (tons/yr)	608.24
Annual pellets (%)	15%
Annual pellets (tons)	29,272.22
emission reduction (tons/yr)	91.24
Cost pellets ($/ton)	$84.00
Annual cost	$2,597,381.16
Annual revenue	$2,315,186.17
annual burden of pellets	$282,194.99
cost/ton removed	3,093.04

6.0 Proposed Alternative BACT – Reduction in Potential to Emit

Aurora proposes to monitor the stack gas emissions out of the common stack. The purpose of the monitoring would be to ensure compliance with an SO_2 emission rate of 190 ppm. Instead of taking a reduction in the sulfur content of the coal or PTE for SO_2 emissions, monitoring the stack gas emissions and maintaining a rolling 30-day average at or under 190 ppm ensures that the plant is not exceeding a certain loading rate equal to 0.25% coal sulfur content. Using the SO_2 emission calculation in the Air Quality Operating permit AQ0315TVP03 Rev. 1, Condition 22.1.c; a stack gas concentration of 7.5% O_2; and adjusting the S% to 0.25 (in this ultimate analysis the S% is 0.26), the SO_2 concentration is 188 ppm as illustrated below:

Figure 1: SO_2 emission calculation

SO2 Concentration PPM = (1.00X 10^6 xmol_{SO2})/(mol_{SO2} +mol_{CO2}+mol_{O2}+mol_{N2})						
SO2 PPM =						
Where:						
mol SO2 =	[wt% Sfuel,%]/32.06					
mol CO2 =	[wt%Cfuel,%]/12.01					
mol O2 =	MF x [(wt%Nfuel,%]/28.01)+(4.76xmolCO2)+(4.76xmolSO2)+(1.88xmolH2O)-(3.76x[wt%Ofuel,%]/32.00)]					
MF =	[vol%O2,exhaust,%]/(100%-4.76x[vol%O2, exhaust, %])					
mol H2O =	[wt%Hfuel,%]/2.016					
mol N2 =	([wt%Nfuel,%]/28.01)+(3.76xmolSO2)+(3.76xmolCO2)+(1.88xmolH2O)+(3.76xmolO2)-([wt% Ofuel,%]/8.51)					
Constituent	mols in flue gas		Ultimate/proximate analysis (AE08162018)	%weight (dry)	Atomic Mass	Atomic Mass
mol_{SO2}	0.007796663		wt% $Sulfur_{fuel}$, %	0.25	Sulphur	32.065
mol_{CO2}	5.219382233		wt% $Carbon_{fuel}$, %	62.69	Carbon	12.011
mol_{H2O}	2.277011608		wt% $Hydrogen_{fuel}$, %	4.59	Hydrogen	1.0079
mol_{O2}	3.098516312		wt% $Nitrogen_{fuel}$, %	0.93	Nitrogen	14.007
mol_{N2}	33.05690137		wt% $Oxygen_{fuel}$, %	21.8	Oxygen	15.999
MF	0.116640747			%vol		
			Oxygen exhaust %	7.5		
SO_2 Concentration	188.404394		Source Test Required if exhaust SO_2 Concentration is greater than 500 ppm			

As mentioned, 190 ppm of SO2 emissions on a 30-day rolling average represents an overall PTE reduction from 0.4% sulfur content to 0.25% while still allowing flexibility with respect to coal quality exceeding 0.25% sulfur.

7.0 Precursor Demonstration

As part of the Serious SIP development, states are required to develop Best Available Control Measures for all source sectors that emit $PM_{2.5}$ and the four major precursor gases (e.g., NOx, SO_2, NH_4, and VOC). The analysis specific to the major stationary source is a Best Available Control Technology analysis. Within the rule, if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls for a precursor gas are not required to be implemented.[19] The regulations provide for three kinds of precursor analyses, comprehensive (which consider precursor emissions from all sources in the nonattainment area), Major stationary source (which consider precursor emissions from major sources), and Nonattainment New Source Review (which considers potential precursor emissions from new sources). [20] For each of the first two analyses, there are two varieties available to the state: a concentration-based analysis (compares the precursor contributions to a numerical threshold) and a sensitivity-based analysis which consider other factors to evaluate if reductions in the precursor emissions would significantly reduce $PM_{2.5}$ levels in a nonattainment area.

The ADEC has successfully demonstrated that oxides of nitrogen NOx and VOC are not a significant precursors to the area. The NOx precursor demonstrations included a comprehensive demonstration with a sensitivity based analysis for the community and a Major Stationary Source – concentration based analysis which demonstrated that major sources are not a significant contributor to the nitrate-based particulate formation.[21] The state also conducted a comprehensive, concentration-based analysis for SO_2 and concluded that SO_2 emissions in the NAA contribute 5.4 $\mu g/m^3$ in the Fairbanks area and 4.9 $\mu g/m^3$ of $PM_{2.5}$ in the North Pole area. Since these concentrations exceed the significance threshold of 1.3 $\mu g/m^3$ (now 1.5 $\mu g/m^3$)[22], the ADEC proposes not to conduct a sensitivity-based precursor demonstration nor are they considering a major source precursor demonstration.

EPA's draft precursor guidance recognizes that the significance of a precursors contribution is determined based on the facts and circumstances of the area which include source characteristics such as source type, stack height, and location.[23] The rationale for doing a precursor demonstration fits with the site-specific factors listed in the EPA guidance, namely tall stacks. However, the ADEC and EPA have been resistant to performing or further considering a Major Source precursor demonstration.

Aurora sought a third party opinion (Ramboll Environmental) regarding the possibility of a successful SO_2 precursor demonstration that could demonstrate that major stationary sources are an insignificant part of the contribution to the nonattainment area. According with the EPA's precursor demonstration guidelines, a successful major stationary source precursor demonstration must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ standard (1.5 $\mu g/m^3$). If the 'contribution-based'

[19] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[20] See 40 C.F.R. § 51.1006
[21] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[22] Draft EPA (2016b) guidance recommended 1.3 $\mu g/m^3$ for the $PM_{2.5}$ 24-hour NAAQS as the appropriate threshold to identify insignificant contributions to $PM_{2.5}$ concentrations. A more recent updated technical basis document, EPA (2018) now recommends a threshold for identifying significance of 1.5 $\mu g/m^3$.
[23] EPA's 2016 Draft $PM_{2.5}$ Precursor Demonstration Guidance.

analysis indicates that the impact 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 have only an insignificant impact on lowering $PM_{2.5}$.

Two main hurdles exist to conducting a credible SO_2 precursor demonstration; 1) the large contribution of sulfate by major and minor source contribution to the nonattainment area; and 2) the large under prediction of sulfate mass through the model (CMAQ). In essence, while the SO_2 sources are observed to contribute significantly to the $PM_{2.5}$ nonattainment area, current modeling systems are not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2.

Utilizing the ADEC's information within the Moderate Area SIP, Aurora's third party consult suggests that there is relevant data to suggest major sources are potentially insignificant contributors to the NAA.

> "…data analyses and modeling conducted for the Fairbanks moderate area SIP provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment."[24]

As such, a Major Source SO_2 precursor demonstration must be pursued by the ADEC. It is an undue burden for Aurora and other major sources within the NAA subject to the requirements of control measures (BACT, and more likely MSM) considering that there is data to suggest that major sources could be insignificant. Even though updating models and research into the chemistry of sulfate particulate formation is costly and time consuming, it is due diligence on the agencies part to further elucidate the impact of major sources. Ultimately, Aurora will continue to pursue alternative control measures as proposed within this document under the assumption that the agencies (ADEC and EPA) will continue to vet the sulfate contribution disparity between model and observed values with the perspective of major stationary source contribution.

8.0 Conclusion

The proposed BACT alternatives in this document and accompanying information demonstrate that the ADEC proposed BACT are economically infeasible and do very little to solve the air quality problem in the nonattainment area. EPA, the State of Alaska, as well as the local community understand and agree that the majority of the $PM_{2.5}$ problem in the area is from home heating sources. Aurora contends that requiring the implementation of the ADEC proposed BACT controls would cause the pollution problem to worsen due to our district heat customer's refusal to accept a higher cost heating product and instead switching to fuel oil, or wood burning.

Aurora does not believe ADEC has demonstrated that the point sources, or more specifically Aurora, are contributing to the $PM_{2.5}$ problem in a significant enough way to warrant the need for additional control measures. Aurora believes that a precursor demonstration would prove this assertion one way or another. Aurora believes a precursor demonstration is possible and requests that ADEC and the EPA move forward with conducting a precursor demonstration in parallel with the implementation of the SIP. Should a precursor demonstration show that the point sources do not cross over the significance threshold, all point sources should be released from further compliance with the $PM_{2.5}$ requirements.

Even though Aurora is not convinced that major source emissions exceed the significance threshold for $PM_{2.5}$ within the NAA, Aurora is interested in being a part of the solution to reduce $PM_{2.5}$. Aurora's

[24] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks".2018.

proposed alternative BACT controls are more effective from an environmental perspective and cost substantially less than the ADEC proposed BACT controls. The table below shows the potential amount of SO_2 and $PM_{2.5}$ removed from the NAA by Aurora's proposed alternative BACT.

Table 15: Summary of BACT Alternatives and Potential Emission Reduction

Emissions	SO2 (tpy)	PM 2.5 (tpy)	Qualifying Parameters
District Heating (Current Operating Conditions)	42 tpy at ground level	2 tons at ground level	250,000 – 300,000 mmbtu per year
District Heating (Potential Expansion)	24 tpy at ground level	1 ton at ground level	100 mmbtu/hr expansion potential
Wood Kiln	608.3tpy	33 tons at ground level	8495 cords/yr
Biomass Co-Firing	91.2 tpy	--	15% by fuel heat input from industrial pellets
Potential to emit reduction	38% reduction in PTE (854 tpy)	--	State upper limit of 500 ppm over 3 hours. Proposed 190 ppm as a new PTE
Total Potential Reduction	1,619.5 tpy	36 tpy	

As clearly shown in this table, the environmental benefits from Aurora's proposed alternative BACTs will positively impact the current NAA. Aurora is prepared to move forward with implementing these alternative BACTs as soon as ADEC is able to provide Aurora with the assurance that additional control measures or fees will not be required in order to demonstrate compliance with the PM2.5 regulations for the NAA.

Aurora is committed to continuing to work with ADEC, EPA and the local community in working toward meaningful solutions to the air quality problem in Interior Alaska.

Appendix A (Economic Analysis Spreadsheets – V1)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 450 Feet above sea level

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (selected) Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80 percent
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	10 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2 acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	30 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50 percent*
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea	
Electricity ($Cost_{elect}$)	0.210 $/kWh	
Catalyst cost ($CC_{replace}$)	160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*	
Operator Labor Rate	63.00 $/hour (including benefits)	

CEPCI = Chemical Engineering Plant Cost Index

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year
NOx removal factor (NRF) =	EF/80	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour
Residence Time	$1/V_{space}$	0.03	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$1,728,014 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$2,921,054 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,723,709 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,728,014 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,921,054 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$4,587 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Is the boiler a fluid-bed boiler?	No
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40 percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05

Plant Elevation 450 Feet above sea level

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Concentration of reagent as stored (C_{stored})	50 percent*
Denisty of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	50 percent
Number of days reagent is stored ($t_{storage}$)	30 days
Estimated equipment life	20 Years
Select the reagent used	Urea

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016
CEPCI for 2016	536.4 Enter the CEPCI value for 2016 · 584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0088 $/gallon*
Electricity ($Cost_{elect}$)	0.210 $/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565 in 2016 dollars
Indirect Annual Costs (IDAC) =	$511,631 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$989,197 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82 in 2016 dollars
Direct Annual Cost =		$477,565 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$508,837 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$511,631 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$989,197 per year in 2016 dollars
NOx Removed =	318 tons/year
Cost Effectiveness =	$3,107 per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.222	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.24**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection, but not including field installatior
Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284)				
Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)				
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	6.64	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.07	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectio
VOMP ($/MWh) = Q*T*10	=	$	0.507	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**9.21**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
				Revise interest rate to prime (currently 5.25%) per EPA comment
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0669	=	$	1,383,976	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**2,430,578**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,015,463**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,601,940**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		546	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**8,423**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.122	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.280	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.462**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.876	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,028,350	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,426,798	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	34,042,802	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,238	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,404,280	Engineering and construction management costs
A2 = 10% of BM	=	$	3,404,280	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,404,280	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,255,642**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,609**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,212,782	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,468,425**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,690**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,646,842	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	=	**$**	**51,115,267**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,859**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.38	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.79**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.06	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.29**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	854,570	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,022,305	CC Manual
Property tax (1% of total capital investment)	=	$	511,153	CC Manual
Insurance (1% of total capital investment)	=	$	511,153	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,420,477	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,319,657**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,499,458**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,716,232**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		702	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**12,408**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.16	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.283	1.811*K
Aux Power	**M**	**(%)**	**2.098**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.913	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars) **Comments**

Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5

Calculation			Value	Comments
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,531,374	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,684,600	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,323,921	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,508,019	Total base cost including retrofit factor
BM ($/kW)	=	$	1,364	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,750,802	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,750,802	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,750,802	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,760,424**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,773**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,438,021	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**51,198,446**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,862**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,119,844.55	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**56,318,290**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,048**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.25**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.36	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.41	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**7.10**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	713,645	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,126,366	CC Manual
Property tax (1% of total capital investment)	=	$	563,183	CC Manual
Insurance (1% of total capital investment)	=	$	563,183	CC Manual
Capital Recovery Factor (CRF) = $[\ i\ (1+i)^n\ ] / [\ (1+i)^n - 1\ ]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,768,647	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,735,024**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,634,230**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,839,892**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		773	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**11,440**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix B (Economic Analysis Spreadsheets – V2)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 450 Feet above sea level

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80 percent
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	10 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2 acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	15 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50 percent*
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea	
Electricity ($Cost_{elect}$)	0.210 $/kWh	
Catalyst cost ($CC_{replace}$)	160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*	
Operator Labor Rate	63.00 $/hour (including benefits)	

CEPCI = Chemical Engineering Plant Cost Index

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year
NOx removal factor (NRF) =	EF/80	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour
Residence Time	$1/V_{space}$	0.03	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0980

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$2,528,093 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$3,721,132 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,523,788 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,528,093 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,721,132 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$5,844 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 497 MMBtu/hr

What is the higher heating value (HHV) of the fuel? 7,560 Btu/lb

What is the estimated actual annual fuel consumption? 569,114,000 lbs/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 365 days

Plant Elevation 450 Feet above sea level

Inlet NO_x Emissions (NOx_{in}) to SNCR 0.37 lb/MMBtu

NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known) 40 percent

Estimated Normalized Stoichiometric Ratio (NSR) 1.05

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

Concentration of reagent as stored (C_{stored}) 50 percent*

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Denisty of reagent as stored (ρ_{stored}) 71 lb/ft^3

Concentration of reagent injected (C_{inj}) 50 percent

Number of days reagent is stored ($t_{storage}$) 30 days

Estimated equipment life 15 Years

Select the reagent used Urea

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent	
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*	
Water ($Cost_{water}$)	0.0088 $/gallon*	
Electricity ($Cost_{elect}$)	0.210 $/kWh	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*	

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0980

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565 in 2016 dollars
Indirect Annual Costs (IDAC) =	$611,129 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$1,088,694 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82 in 2016 dollars
Direct Annual Cost =		$477,565 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$608,335 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$611,129 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,088,694 per year in 2016 dollars
NOx Removed =	318 tons/year
Cost Effectiveness =	$3,419 per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.28	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.185	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.20**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($) Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection,but not including field installatior
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	5.53	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.00	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectioi
VOMP ($/MWh) = Q*T*10	=	$	0.423	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**7.96**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 15				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0980	=	$	2,026,363	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**3,072,965**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,356,087**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,914,480**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		456	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**10,785**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.101	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.234	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.461**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.874	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,004,722	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,268,968	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	33,861,344	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,231	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,386,134	Engineering and construction management costs
A2 = 10% of BM	=	$	3,386,134	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,386,134	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,019,747**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,601**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,200,987	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,220,735**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,681**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,622,073	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**50,842,808**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,849**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.73**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	0.88	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.25	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.06**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	853,468	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,016,856	CC Manual
Property tax (1% of total capital investment)	=	$	508,428	CC Manual
Insurance (1% of total capital investment)	=	$	508,428	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	4,981,433	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**7,868,614**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**10,990,629**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,084,456**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		586	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**17,213**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.13	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.236	1.811*K
Aux Power	**M**	**(%)**	**2.079**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.908	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,485,962	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,542,315	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,220,076	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,216,477	Total base cost including retrofit factor
BM ($/kW)	=	$	1,353	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,721,648	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,721,648	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,721,648	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,381,420**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,759**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,419,071	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**50,800,491**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,847**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,080,049.08	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**55,880,540**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,032**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.53	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.14**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.14	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.26	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.37	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**6.78**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	711,875	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,117,611	CC Manual
Property tax (1% of total capital investment)	=	$	558,805	CC Manual
Insurance (1% of total capital investment)	=	$	558,805	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	5,475,016	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**8,422,112**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**11,241,441**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,314,589**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		644	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**16,005**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix C (Coal Analyses Summary)

Coal Analyses Summary (As Received)					
Year	Report	Coal	HHV	Moisture	Sulfur
Units		(tons)	(btu/lb)	(%)	(%)
2013	A	103,122.35	7,670	27.22	0.15
2013	B	115,917.00	7,599	27.95	0.17
2014	A	117,659.65	7,652	27.89	0.15
2014	B	103,979.45	7,617	27.86	0.14
2015	A	103,904.80	7,599	29.16	0.14
2015	B	120,758.30	7,610	29.02	0.15
2016	A	115,282.20	7,683	31.21	0.12
2016	B	107,687.35	7,604	29.23	0.14
2017	A	106,040.35	7,567	32.20	0.11
2017	B	114,440.00	7,529	32.52	0.10
Weighted average		221,758.29	7,613	29.44	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 6/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	7552	28.06	8.58	36.44	26.93	0.12	TII	V6	6	1,177.90
AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	16906.60	7511.00	28.08	8.95	35.75	27.23	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2013	10	7504	27.93	9.16	34.93	27.98	0.20	T II	T4	4	961.05
AURORA ENERGY LLC	1/3/2013	11	7599	26.87	9.32	35.99	27.83	0.18	P2/STK	C1	6/N	1,000.35
AURORA ENERGY LLC	1/4/2013	9	7685	27.59	8.22	36.39	27.81	0.17	P2/STK	C1	6/N	816.20
AURORA ENERGY LLC	1/5/2013	13	7711	27.47	8.17	36.74	27.63	0.18	P2/STK	C1	6/N	1,263.55
AURORA ENERGY LLC	1/7/2013	11	7612	27.77	8.70	35.41	28.12	0.17	P2/STK	C1	6/N	1,057.50
AURORA ENERGY LLC	1/8/2013	9	7565	26.55	10.25	35.37	27.84	0.17	TII/P2	T4/C1	4/6	858.05
AURORA ENERGY LLC	1/9/2013	12	7584	27.03	9.43	35.53	28.01	0.18	T II/P2	T4/C1	4/6	1,113.90
AURORA ENERGY LLC	1/10/2013	6	7692	25.65	9.78	36.60	27.96	0.17	P2/STK	C1	6/N	562.40
AURORA ENERGY LLC	1/11/2013	13	7507	27.09	10.00	35.86	27.05	0.18	P2/STK	C1	6/N	1,223.50
AURORA ENERGY LLC	1/14/2013	9	7566	26.87	9.70	35.71	27.72	0.16	P2/STK	C1	6/N	872.75
AURORA ENERGY LLC	1/15/2013	14	7632	28.16	8.04	35.42	28.38	0.20	TII	T4	4	1,261.60
AURORA ENERGY LLC	1/16/2013	12	7784	27.66	7.41	36.36	28.57	0.17	TII	T4	4	1,096.85
AURORA ENERGY LLC	1/17/2013	7	7758	27.48	8.08	35.70	28.75	0.19	P2/STK	C1	6/N	645.20
AURORA ENERGY LLC	1/18/2013	11	7788	26.88	7.92	36.52	28.68	0.16	P2/STK	C1	6/N	1,007.45
AURORA ENERGY LLC	1/21/2013	8	7678	26.95	8.63	35.72	28.71	0.17	T II/STK	T4	4/N	737.10
AURORA ENERGY LLC	1/22/2013	13	7709	27.10	8.34	35.59	28.98	0.18	T II/STK	T4	4/N	1,166.85
AURORA ENERGY LLC	1/23/2013	14	7746	27.10	8.39	36.04	28.47	0.17	P2/STK	C1	6/S	1,223.50
AURORA ENERGY LLC	1/25/2013	7	7754	27.88	7.45	36.79	27.89	0.15	P2/STK	C1	6/N	633.50
AURORA ENERGY LLC	1/25/2013	11	7585	26.81	9.72	36.20	27.28	0.15	P2/STK	C1	6/N	994.60
AURORA ENERGY LLC	1/28/2013	9	7484	26.40	11.09	35.58	26.94	0.15	P2/STK	C1	6/S	807.55
AURORA ENERGY LLC	1/29/2013	11	7691	26.62	9.22	36.11	28.05	0.15	P2/STK	C1	6/S	994.45
AURORA ENERGY LLC	1/30/2013	13	7482	28.23	9.21	35.05	27.52	0.16	P2/STK	C1	6/S	1,150.80
AURORA ENERGY LLC	1/31/2013	10	7460	26.87	10.25	34.89	27.99	0.15	TII/P2	T3/C1	3/6	920.60
AURORA ENERGY LLC	2/1/2013	8	7529	28.24	9.08	35.07	27.61	0.14	TII	T3	3	763.65
AURORA ENERGY LLC	2/4/2013	7	7545	28.48	8.71	34.47	28.34	0.13	TII	T3	3	629.95
AURORA ENERGY LLC	2/5/2013	11	7463	28.30	9.56	34.22	27.92	0.14	T II	T3	3	1,015.15
AURORA ENERGY LLC	2/7/2013	8	7491	28.60	8.93	34.76	27.72	0.13	P2/TII	C1/T3	6/3	755.05
AURORA ENERGY LLC	2/8/2013	12	7637	27.97	8.09	36.09	27.86	0.14	P2/TII	C1/T3	6/3	1,113.25
AURORA ENERGY LLC	2/9/2013	12	7740	26.73	8.61	37.24	27.42	0.14	P2	C1	6	1,102.05
AURORA ENERGY LLC	2/11/2013	9	7506	26.87	9.55	35.20	28.38	0.16	T II/P2	T3/C1	3/6	848.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	2/12/2013	15	7649	27.94	8.20	35.09	28.77	0.15	T II	T3	3	1,378.10
AURORA ENERGY LLC	2/13/2013	21	7556	27.99	9.13	34.51	28.38	0.15	T II	T3	3	1,914.10
AURORA ENERGY LLC	2/14/2013	8	7819	26.40	8.38	36.31	28.91	0.14	P2/STK	C1	6/N	701.80
AURORA ENERGY LLC	2/15/2013	15	7437	27.31	10.59	34.59	27.51	0.15	P2/STK	C1	6/S	1,300.35
AURORA ENERGY LLC	2/18/2013	9	7616	27.77	8.69	34.75	28.80	0.14	TII	T3	3	852.10
AURORA ENERGY LLC	2/19/2013	5	8065	26.73	6.36	37.32	29.59	0.13	P2/STK	C1	6/S	448.60
AURORA ENERGY LLC	2/20/2013	18	7824	27.32	7.48	37.11	28.09	0.15	P2/STK	C1	6/S	1,648.60
AURORA ENERGY LLC	2/21/2013	7	7607	26.43	10.17	36.29	27.11	0.15	P2/STK	C1	6/S	615.40
AURORA ENERGY LLC	2/22/2013	15	7510	28.05	9.42	35.26	27.28	0.14	TII	T3	3	1,390.45
AURORA ENERGY LLC	2/25/2013	9	7697	28.21	7.72	34.80	29.27	0.14	TII	T3	3	817.70
AURORA ENERGY LLC	2/26/2013	14	7588	28.23	8.43	35.08	28.26	0.14	TII/P2	T3/C1	3/6	1,275.05
AURORA ENERGY LLC	2/28/2013	17	7872	27.40	6.91	37.27	28.43	0.15	P2/STK	C1	6/S	1,587.05
AURORA ENERGY LLC	3/4/2013	11	7508	26.13	11.00	35.23	27.65	0.15	P2/TII	C1/T3	6/3	1,033.95
AURORA ENERGY LLC	3/5/2013	11	7682	26.99	8.13	36.34	28.55	0.14	P2/STK	C1	6/S	959.30
AURORA ENERGY LLC	3/6/2013	14	7648	27.25	7.96	36.56	28.23	0.15	P2/STK	C1	6/S	1,302.85
AURORA ENERGY LLC	3/7/2013	7	7717	26.40	8.27	37.82	27.53	0.15	P2/STK	C1	6/S	619.15
AURORA ENERGY LLC	3/8/2013	6	7469	26.55	9.86	37.18	26.41	0.16	P2/STK	C1	6/S	538.30
AURORA ENERGY LLC	3/11/2013	11	7857	27.02	7.45	37.34	28.20	0.15	P2/STK	C1	6/S	1,016.00
AURORA ENERGY LLC	3/12/2013	13	7868	26.99	7.27	37.32	28.43	0.14	P2/STK	C1	6/S	1,200.55
AURORA ENERGY LLC	3/13/2013	18	7437	28.70	8.86	35.07	27.37	0.14	P2/STK	C1	6/S	1,586.50
AURORA ENERGY LLC	3/15/2013	7	7253	25.91	13.37	35.02	25.70	0.14	P2/STK	C1	6/S	652.45
AURORA ENERGY LLC	3/19/2013	11	7570	26.44	10.41	36.24	26.91	0.16	P2/STK	C1	6/S	1,034.15
AURORA ENERGY LLC	3/19/2013	8	7723	26.43	9.14	36.80	27.63	0.14	P2/STK	C1	6/S	734.00
AURORA ENERGY LLC	3/20/2013	11	7812	26.67	8.36	36.58	28.40	0.15	P2/STK	C1	6/S	1,058.60
AURORA ENERGY LLC	3/21/2013	3	7805	26.35	8.46	36.75	28.44	0.15	P2/STK	C1	6/S	264.35
AURORA ENERGY LLC	3/22/2013	8	7580	26.59	10.17	36.01	27.24	0.15	P2/STK	C1	6/S	747.60
AURORA ENERGY LLC	3/25/2013	6	7835	26.61	7.98	37.07	28.35	0.15	P2/STK	C1	6/S	545.80
AURORA ENERGY LLC	3/26/2013	10	7873	26.37	7.94	37.21	28.48	0.16	P2/STK	C1	6/S	911.95
AURORA ENERGY LLC	3/27/2013	11	7633	26.67	9.68	35.80	27.86	0.16	P2/STK	C1	6/S	1,011.95
AURORA ENERGY LLC	3/28/2013	4	7776	26.70	8.29	37.09	27.93	0.15	P2/STK	C1	6/S	363.85
AURORA ENERGY LLC	4/1/2013	6	7964	26.30	7.22	37.59	28.89	0.15	P2/STK	C1	6/S	527.90
AURORA ENERGY LLC	4/2/2013	11	[illegible]	[illegible]	[illegible]	[illegible]	29.16	0.15	P2/STK	C1	6/S	993.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	4/3/2013	10	7812	27.29	7.75	36.64	28.33	0.14	P2/STK	C1	6/S	935.20
AURORA ENERGY LLC	4/4/2013	5	7779	26.72	8.53	36.84	27.92	0.14	P2/STK	C1	6/S	458.50
AURORA ENERGY LLC	4/5/2013	9	7866	26.26	8.67	36.80	28.28	0.15	P2/STK	C1	6/N	855.30
AURORA ENERGY LLC	4/8/2013	10	7363	27.30	11.58	34.23	26.89	0.16	P2/JDRC	C1/C13	6/3	934.30
AURORA ENERGY LLC	4/9/2013	14	7381	29.34	8.61	35.20	26.86	0.14	TII	V6	6	1,269.45
AURORA ENERGY LLC	4/11/2013	10	7736	28.34	7.26	36.44	27.97	0.15	TII	V6	6	885.25
AURORA ENERGY LLC	4/11/2013	6	7591	28.62	7.89	36.55	26.95	0.14	TII	V6	6	556.70
AURORA ENERGY LLC	4/16/2013	11	7286	29.40	11.50	32.67	26.44	0.15	JD/GRP	C13	3/C	1,062.00
AURORA ENERGY LLC	4/16/2013	10	7385	29.01	10.61	33.14	27.25	0.17	JDRC	C13	3	939.50
AURORA ENERGY LLC	4/18/2013	8	7746	27.55	7.98	36.17	28.31	0.15	T II	V6	6	730.15
AURORA ENERGY LLC	4/20/2013	8	7783	26.84	9.01	35.88	28.28	0.16	T II/STK	V6	6/W	750.40
AURORA ENERGY LLC	4/22/2013	7	7659	27.90	8.10	36.27	27.74	0.16	T II/STK	V6	6/W	657.70
AURORA ENERGY LLC	4/23/2013	8	7706	27.47	8.38	36.53	27.61	0.16	T II/STK	V6	6/W	741.05
AURORA ENERGY LLC	4/25/2013	9	7589	27.83	8.91	36.03	27.24	0.15	T II	V6	6	856.65
AURORA ENERGY LLC	4/25/2013	7	7505	26.90	10.26	36.16	26.69	0.14	TII	V6	6	640.30
AURORA ENERGY LLC	4/26/2013	8	7601	27.54	8.54	37.23	26.69	0.15	TII	V6	6	746.30
AURORA ENERGY LLC	4/29/2013	10	7495	28.32	8.82	35.78	27.09	0.14	T II	V6	6	915.65
AURORA ENERGY LLC	4/30/2013	12	7123	27.64	12.55	34.60	25.21	0.14	T II	V6	6	1,130.20
AURORA ENERGY LLC	5/1/2013	12	7962	24.90	11.11	35.05	28.95	0.17	GRP/STK		M/N	1,238.65
AURORA ENERGY LLC	5/2/2013	10	7815	25.21	11.77	34.52	28.51	0.17	GRP/STK		M/S	940.15
AURORA ENERGY LLC	5/3/2013	7	7574	25.05	13.91	33.39	27.66	0.18	GRP/STK		M/S	670.35
AURORA ENERGY LLC	5/3/2013	13	8042	24.57	11.80	34.49	29.14	0.18	GRP/STK		M/S	1,223.00
AURORA ENERGY LLC	5/6/2013	3	8200	23.89	10.98	34.73	30.41	0.19	GRP/STK		M/N	278.80
AURORA ENERGY LLC	5/20/2013	8	7876	26.05	9.72	36.04	28.19	0.16	GRP/STK		M/N	765.10
AURORA ENERGY LLC	5/21/2013	16	8437	24.71	8.98	35.53	30.78	0.18	GRP/STK		M/N	1,459.45
AURORA ENERGY LLC	5/23/2013	10	8746	23.37	8.77	35.33	32.54	0.18	GRP		M	954.30
AURORA ENERGY LLC	5/23/2013	11	8414	24.03	9.96	34.57	31.45	0.17	GRP		M	1,064.60
AURORA ENERGY LLC	5/27/2013	9	8508	23.93	9.27	35.49	31.31	0.18	GRP/STK		M/N	819.70
AURORA ENERGY LLC	5/28/2013	12	8514	24.06	9.27	35.30	31.38	0.18	GRP/STK		M/N	1,151.15
AURORA ENERGY LLC	5/30/2013	10	7619	27.91	8.56	36.48	27.05	0.13	T II	V6	6	956.70
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	[illegible]	[illegible]	[illegible]	36.44	26.93	0.12	TII	V6	6	1,177.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103122.35	7670.00	27.22	9.05	35.76	27.98	0.15

This analysis is representative of the coal shipped
using sulfur standard ASTM D4239-12

Coleen Thompson

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2013	7	7360	26.50	11.80	35.40	26.30	0.15	TBR	C1	6	652.55
AURORA ENERGY LLC	7/2/2013	21	7675	26.40	9.51	36.33	27.77	0.15	TBR	C1	6	1,961.70
AURORA ENERGY LLC	7/5/2013	23	7565	27.34	9.39	34.94	28.34	0.19	T II	U4	4	2,171.90
AURORA ENERGY LLC	7/8/2013	10	7538	28.53	8.36	34.23	28.88	0.19	TII	U4	4	917.50
AURORA ENERGY LLC	7/9/2013	29	7645	28.51	7.49	35.44	28.57	0.16	T II	U4	4	2,700.95
AURORA ENERGY LLC	7/11/2013	13	7502	28.50	8.82	35.62	27.06	0.18	TBR	C1	6	1,224.95
AURORA ENERGY LLC	7/15/2013	12	7485	29.53	7.66	35.01	27.81	0.19	TII	U4	4	1,067.35
AURORA ENERGY LLC	7/16/2013	11	7317	27.95	10.29	34.12	27.68	0.25	T II	U4	4	1,019.50
AURORA ENERGY LLC	7/22/2013	11	7609	28.80	7.97	34.86	28.37	0.18	TII	U4	4	1,018.45
AURORA ENERGY LLC	7/24/2013	25	7467	28.43	8.50	34.68	28.41	0.19	T II	U4	4	2,303.20
AURORA ENERGY LLC	7/25/2013	13	7416	28.52	9.36	34.76	27.37	0.20	TII	U4	4	1,239.20
AURORA ENERGY LLC	7/29/2013	9	7339	29.30	9.16	33.88	27.67	0.20	T II	U4	4	836.20
AURORA ENERGY LLC	8/1/2013	27	7749	27.87	8.65	34.52	28.97	0.15	JR/GRP	C13	4/M	2,483.15
AURORA ENERGY LLC	8/5/2013	10	7833	27.43	9.00	34.23	29.35	0.17	JD/GRP	C13	4/M	948.40
AURORA ENERGY LLC	8/6/2013	18	7752	29.20	7.09	34.40	29.31	0.14	JR/GRP	C13	4/M	1,657.00
AURORA ENERGY LLC	8/8/2013	12	7737	28.58	7.91	34.30	29.22	0.14	JR/GRP	C13	4/M	1,172.25
AURORA ENERGY LLC	8/8/2013	16	7648	28.65	8.33	34.49	28.53	0.13	JR/GRP	C13	4/M	1,524.25
AURORA ENERGY LLC	8/9/2013	12	7552	28.48	8.20	35.34	27.99	0.20	TII	U4	4	1,085.70
AURORA ENERGY LLC	8/12/2013	7	7610	28.79	7.51	34.66	29.05	0.16	TII	U4	4	657.40
AURORA ENERGY LLC	8/13/2013	17	7503	29.40	8.11	34.39	28.11	0.15	JR/T II	C13/U4	4/4	1,550.05
AURORA ENERGY LLC	8/19/2013	9	7696	28.53	8.03	34.46	29.00	0.16	JR	C13	4	834.85
AURORA ENERGY LLC	8/20/2013	17	7764	28.71	7.65	34.86	28.79	0.14	JR/GRP	C13	4/M	1,569.00
AURORA ENERGY LLC	8/22/2013	11	8309	24.18	10.01	34.82	31.00	0.20	GRP/STK		M/N	1,008.60
AURORA ENERGY LLC	8/22/2013	15	8288	24.11	9.99	35.32	30.58	0.17	GRP/STK		M/N	1,412.05
AURORA ENERGY LLC	8/26/2013	5	7656	27.01	10.63	33.80	28.57	0.19	T II/GRP	U3	3/M	491.15
AURORA ENERGY LLC	8/27/2013	12	7557	27.38	10.91	33.44	28.26	0.15	T II/GRP	U3	3/M	1,141.90
AURORA ENERGY LLC	8/28/2013	10	7705	27.60	9.20	34.46	28.74	0.14	T II/GRP	U3	3/M	905.40
AURORA ENERGY LLC	8/29/2013	12	7822	26.89	10.18	34.14	28.79	0.15	TII/GRP	U3	3/M	1,149.70
AURORA ENERGY LLC	9/3/2013	11	7996	26.39	10.28	34.01	29.33	0.16	TII/GRP	U3	3/M	1,048.10
AURORA ENERGY LLC	9/5/2013	10	7654	26.76	10.82	33.81	28.61	0.15	T II/GRP	U3	3/M	935.45

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Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	9/5/2013	12	7566	28.02	8.70	34.71	28.58	0.12	T II	U3	3	1,051.50
AURORA ENERGY LLC	9/7/2013	9	7584	28.16	8.73	35.10	28.01	0.12	T II	U3	3	808.00
AURORA ENERGY LLC	9/9/2013	5	7525	28.89	8.44	34.02	28.66	0.13	T II	U3	3	479.85
AURORA ENERGY LLC	9/11/2013	20	6894	29.54	12.49	32.88	25.09	0.13	JR	C13	3	1,938.20
AURORA ENERGY LLC	9/13/2013	20	7578	27.99	8.74	34.77	28.50	0.13	TII/STK	U3	3/N	1,900.70
AURORA ENERGY LLC	9/16/2013	8	7507	27.68	9.36	34.53	28.43	0.12	TII	U3	3	769.35
AURORA ENERGY LLC	9/18/2013	12	7474	28.91	8.87	34.24	27.99	0.13	T II	U3	3	1,134.85
AURORA ENERGY LLC	9/19/2013	18	7447	28.38	9.45	34.11	28.06	0.12	T II	U3	3	1,756.50
AURORA ENERGY LLC	9/20/2013	15	7567	28.36	8.52	34.37	28.75	0.12	T II	U3	3	1,459.60
AURORA ENERGY LLC	9/24/2013	21	7503	27.57	9.98	35.65	26.81	0.15	TBR	C1	6	2,034.85
AURORA ENERGY LLC	9/25/2013	15	7615	26.60	9.92	36.33	27.16	0.15	TBR	C1	6	1,425.25
AURORA ENERGY LLC	9/26/2013	13	7626	26.57	9.47	37.08	26.88	0.15	TBR	C1	6	1,261.65
AURORA ENERGY LLC	9/30/2013	6	7556	26.97	10.47	35.62	26.95	0.15	TBR	C1	6	572.95
AURORA ENERGY LLC	10/2/2013	8	7354	27.62	11.21	33.98	27.20	0.18	TBR	C1	6	758.30
AURORA ENERGY LLC	10/7/2013	11	7515	27.82	9.13	34.36	28.69	0.16	T II	V4	4	1,009.45
AURORA ENERGY LLC	10/10/2013	23	7298	28.57	10.30	33.77	27.36	0.15	T II	V4	4	2,203.90
AURORA ENERGY LLC	10/11/2013	17	7295	28.25	10.17	34.26	27.32	0.21	TII	V4	4	1,618.40
AURORA ENERGY LLC	10/15/2013	13	7770	27.43	8.67	34.47	29.43	0.21	T II	V4	4	1,250.95
AURORA ENERGY LLC	10/16/2013	9	7622	28.16	8.19	34.71	28.94	0.18	T II	V4	4	834.60
AURORA ENERGY LLC	10/17/2013	16	7560	28.73	7.77	34.73	28.78	0.19	T II	V4	4	1,448.90
AURORA ENERGY LLC	10/18/2013	13	7582	27.73	7.91	35.43	28.93	0.18	TII	V4	4	1,209.15
AURORA ENERGY LLC	10/21/2013	15	7584	27.84	9.19	34.45	28.53	0.20	T II	V4	4	1,476.80
AURORA ENERGY LLC	10/22/2013	13	7492	28.05	9.43	34.58	27.95	0.20	T II	V4	4	1,280.80
AURORA ENERGY LLC	10/23/2013	18	7557	28.26	8.52	34.70	28.52	0.20	T II	V4	4	1,756.85
AURORA ENERGY LLC	10/26/2013	14	7539	27.86	9.52	34.75	27.88	0.20	T II/T II	V4/W4	4/4	1,307.25
AURORA ENERGY LLC	10/28/2013	13	7536	27.75	9.19	34.92	28.15	0.20	TII	W4	4	1,171.30
AURORA ENERGY LLC	10/29/2013	12	7871	28.27	5.87	35.86	30.00	0.14	Bdl	Bx	3	1,070.25
AURORA ENERGY LLC	10/30/2013	13	7644	27.59	8.16	34.73	29.52	0.12	Bdl	C4	3	1,251.70
AURORA ENERGY LLC	11/2/2013	17	7709	28.33	7.68	35.49	28.50	0.15	T II	W4	4	1,561.60
AURORA ENERGY LLC	11/4/2013	9	7745	28.25	7.16	35.46	29.13	0.17	Bdl	C4	3	828.45
AURORA ENERGY LLC	11/5/2013	11	7603	28.42	8.04	34.70	28.84	0.16	T II	W4	4	1,007.45
AURORA ENERGY LLC	11/6/2013	14	7565	28.35	8.34	34.79	28.52	0.18	T II	W4	4	1,280.20

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Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	11/7/2013	11	7677	28.65	6.91	35.74	28.70	0.13	T II	W4	4	939.25
AURORA ENERGY LLC	11/8/2013	8	7833	27.17	7.05	36.48	29.30	0.13	Bdl	C4	3	726.25
AURORA ENERGY LLC	11/12/2013	13	7498	28.03	9.12	34.66	28.19	0.21	TII	W4	4	1,230.50
AURORA ENERGY LLC	11/13/2013	17	7622	28.11	7.98	34.84	29.08	0.20	T II	W4	4	1,615.85
AURORA ENERGY LLC	11/14/2013	15	7466	27.50	9.91	34.21	28.39	0.21	TII	W4	4	1,368.50
AURORA ENERGY LLC	11/15/2013	12	7512	28.08	8.72	34.44	28.78	0.20	TII	W4	4	1,137.60
AURORA ENERGY LLC	11/18/2013	12	7497	27.70	9.39	34.26	28.65	0.21	TII	W4	4	1,169.75
AURORA ENERGY LLC	11/19/2013	13	7183	26.91	12.26	33.66	27.18	0.23	TII	W4	4	1,238.50
AURORA ENERGY LLC	11/20/2013	10	7196	27.55	12.16	33.17	27.13	0.25	T II	W4	4	928.10
AURORA ENERGY LLC	11/21/2013	3	7305	27.84	11.04	33.48	27.65	0.25	T II	W4	4	282.10
AURORA ENERGY LLC	11/22/2013	9	7444	28.14	9.57	34.53	27.77	0.22	TII	W4	4	853.00
AURORA ENERGY LLC	11/23/2013	25	7557	28.84	7.91	34.72	28.54	0.19	TII	W4	4	2,370.10
AURORA ENERGY LLC	11/26/2013	3	7521	28.65	8.47	34.71	28.18	0.20	TII	W4	4	292.95
AURORA ENERGY LLC	11/27/2013	14	7453	28.74	9.06	34.31	27.89	0.20	TII	W4	4	1,322.45
AURORA ENERGY LLC	11/29/2013	10	7658	27.34	8.86	34.71	29.09	0.16	TII/STK	W4	3/N	946.40
AURORA ENERGY LLC	12/2/2013	17	7630	28.09	8.37	34.99	28.56	0.18	TII	W4	4	1,494.70
AURORA ENERGY LLC	12/3/2013	10	7595	28.49	8.08	34.80	28.63	0.20	T II	W4	4	869.90
AURORA ENERGY LLC	12/4/2013	10	7734	27.36	7.78	35.11	29.76	0.17	T II	W4	4	904.75
AURORA ENERGY LLC	12/5/2013	8	7810	27.74	6.95	35.21	30.10	0.13	Bdl	C4	3	763.85
AURORA ENERGY LLC	12/9/2013	11	7711	27.99	7.91	34.53	29.57	0.13	Bdl/TII	C4/W4	3/4	1,063.85
AURORA ENERGY LLC	12/10/2013	13	7739	27.62	7.73	34.74	29.92	0.13	Bdl	C4	3	1,275.10
AURORA ENERGY LLC	12/11/2013	9	7674	27.46	8.60	34.24	29.71	0.13	Bdl	C4	3	881.40
AURORA ENERGY LLC	12/13/2013	3	7696	27.89	8.39	34.21	29.51	0.11	Bdl/STK	C4	3/N	286.75
AURORA ENERGY LLC	12/16/2013	9	7702	27.46	8.54	34.06	29.94	0.12	Bdl	C4	3	852.80
AURORA ENERGY LLC	12/17/2013	8	7800	27.48	7.89	34.58	30.05	0.13	Bdl	C4	4	776.85
AURORA ENERGY LLC	12/18/2013	12	7960	27.33	6.37	35.46	30.85	0.13	Bdl	C4	3	1,176.55
AURORA ENERGY LLC	12/19/2013	10	7856	28.26	6.73	34.92	30.10	0.12	Bdl	C4	3	966.55
AURORA ENERGY LLC	12/20/2013	7	7801	27.63	7.58	34.88	29.92	0.13	Bdl/STK	C4	3/N	669.90
AURORA ENERGY LLC	12/23/2013	15	7802	28.04	7.12	34.75	30.09	0.12	Bdl/STK	C4	3/N	1,473.00
AURORA ENERGY LLC	12/24/2013	15	7676	27.81	8.37	34.17	29.65	0.15	Bdl/STK	C4	3/N	1,459.65
AURORA ENERGY LLC	12/27/2013	5	7632	28.24	8.14	35.09	28.53	0.19	TII	X4	4	431.00
AURORA ENERGY LLC	12/27/2013	6	7575	28.27	8.62	34.41	27.70	0.22	TII	X4	4	547.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	12/29/2013	27	7744	27.93	7.68	35.17	29.23	0.17	TII	X4	4	2,307.45
AURORA ENERGY LLC	12/30/2013	10	7520	27.94	9.09	34.77	28.20	0.22	T II	X4	4	942.95
AURORA ENERGY LLC	12/31/2013	8	7602	27.77	8.55	34.81	28.87	0.22	T II	X4	4	744.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115917.70	7599.00	27.95	8.81	34.72	28.53	0.17

This analysis is representative of the coal shipped using sulfur standard ASTM D4239-12

Coleen Thompson
1-3-14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2014	15	7592	27.80	8.87	34.55	28.78	0.20	T II	X4	4	1,370.90
AURORA ENERGY LLC	1/3/2014	15	7615	29.16	7.32	35.00	28.52	0.17	TII	X4	4	1,440.35
AURORA ENERGY LLC	1/6/2014	8	7633	28.42	7.70	34.85	29.03	0.16	T II	X4	4	779.40
AURORA ENERGY LLC	1/7/2014	12	7642	28.93	7.31	34.80	28.97	0.17	TII	X4	4	1,137.10
AURORA ENERGY LLC	1/8/2014	13	7615	28.31	8.20	34.76	28.74	0.19	T II	X4	4	1,229.35
AURORA ENERGY LLC	1/9/2014	11	7538	28.03	8.94	34.41	28.63	0.23	T II	X4	4	1,070.75
AURORA ENERGY LLC	1/10/2014	13	7571	28.86	8.02	34.63	28.49	0.18	TII	X4	4	1,216.15
AURORA ENERGY LLC	1/13/2014	10	7453	27.84	9.86	34.82	27.48	0.22	TII	X4	4	984.25
AURORA ENERGY LLC	1/14/2014	11	7489	28.42	8.99	34.32	28.27	0.22	Bdl	C4	3	1,031.80
AURORA ENERGY LLC	1/15/2014	8	7608	28.12	8.69	34.32	28.87	0.20	T II	X4	4	756.60
AURORA ENERGY LLC	1/16/2014	13	7588	28.25	8.55	34.40	28.80	0.20	T II	X4	4	1,251.05
AURORA ENERGY LLC	1/18/2014	16	7679	29.63	6.32	34.82	29.24	0.14	TII	X4	4	1,478.00
AURORA ENERGY LLC	1/20/2014	10	7735	28.53	7.06	34.71	29.71	0.16	T II	X4	4	953.85
AURORA ENERGY LLC	1/21/2014	9	7833	28.40	6.48	34.96	30.17	0.13	Bdl	C4	3	805.85
AURORA ENERGY LLC	1/22/2014	12	7767	27.95	7.35	34.72	29.99	0.13	Bdl	C4	3	1,168.20
AURORA ENERGY LLC	1/23/2014	3	7759	28.53	7.30	34.21	29.97	0.13	Bdl	C4	3	293.50
AURORA ENERGY LLC	1/27/2014	9	7379	28.65	9.78	33.16	28.41	0.12	Bdl/JR	C4/C13	3/3	853.10
AURORA ENERGY LLC	1/28/2014	9	7700	28.25	7.82	34.50	29.43	0.15	Bdl/JR	C4/C13	3/3	810.95
AURORA ENERGY LLC	1/29/2014	10	7721	28.70	7.00	34.48	29.82	0.14	Bdl/STK	C4	3/N	917.25
AURORA ENERGY LLC	1/30/2014	15	7737	28.41	7.34	34.81	29.44	0.13	Bdl	C4	3	1,357.75
AURORA ENERGY LLC	1/31/2014	22	7529	29.01	8.13	33.66	29.21	0.12	Bdl	C4	3	2,046.90
AURORA ENERGY LLC	2/3/2014	19	7560	28.92	8.26	33.56	29.26	0.14	Bdl	C4	3	1,809.10
AURORA ENERGY LLC	2/4/2014	12	7527	29.18	8.14	33.53	29.14	0.13	Bdl/ T II	C4/X3	3/3	1,138.90
AURORA ENERGY LLC	2/5/2014	6	7533	28.73	8.62	34.00	28.66	0.13	TII	X3	3	549.45
AURORA ENERGY LLC	2/6/2014	9	7582	28.26	8.89	33.92	28.93	0.12	T II	X3	3	833.35
AURORA ENERGY LLC	2/10/2014	11	7548	28.78	8.49	33.65	29.08	0.13	T II	X3	3	997.40
AURORA ENERGY LLC	2/12/2014	13	7669	28.02	8.03	34.85	29.10	0.13	T II	X3	3	1,178.00
AURORA ENERGY LLC	2/12/2014	8	7568	27.51	9.42	34.40	28.68	0.12	T II	X3	3	735.35
AURORA ENERGY LLC	2/13/2014	12	7810	26.92	8.17	35.24	29.67	0.19	Bdl	A	4	1,085.25
AURORA ENERGY LLC	2/15/2014	10	7841	26.99	7.79	36.16	29.07	0.21	Bdl	A	4	964.15

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Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	2/17/2014	8	7821	26.21	8.59	36.19	29.02	0.26	Bdl	A	4	771.90
AURORA ENERGY LLC	2/18/2014	12	7857	26.05	8.45	35.90	29.61	0.23	Bdl	A	4	1,099.50
AURORA ENERGY LLC	2/19/2014	16	7803	26.19	8.75	35.91	29.15	0.21	Bdl/STK	A	4/N	1,524.75
AURORA ENERGY LLC	2/20/2014	7	7738	26.33	9.11	35.75	28.82	0.20	Bdl/STK	A	4/N	670.45
AURORA ENERGY LLC	2/21/2014	18	7702	26.91	8.70	35.77	28.63	0.20	Bdl/STK	A	4/N	1,716.05
AURORA ENERGY LLC	2/24/2014	13	7721	27.34	8.35	35.25	29.07	0.19	Bdl/STK	A	4/N	1,244.25
AURORA ENERGY LLC	2/25/2014	14	7663	27.53	8.50	34.81	29.15	0.15	TII/Bdl	X3/A	3/4	1,314.15
AURORA ENERGY LLC	2/27/2014	18	7704	27.80	7.88	35.13	29.20	0.14	T II	X3	3	1,743.25
AURORA ENERGY LLC	2/28/2014	19	7519	28.26	8.83	34.59	28.33	0.13	Bdl/T II	A/X3	4/3	1,856.75
AURORA ENERGY LLC	3/3/2014	11	7539	28.91	8.17	33.90	29.03	0.11	TII/Bdl	X3/A	3/4	1,078.75
AURORA ENERGY LLC	3/4/2014	13	7678	26.91	9.19	35.01	28.89	0.23	Bdl/STK	B	4/N	1,195.00
AURORA ENERGY LLC	3/5/2014	11	7784	26.75	8.53	35.75	28.96	0.21	Bdl/STK	B	4/N	1,084.80
AURORA ENERGY LLC	3/6/2014	7	7723	26.83	8.71	35.41	29.05	0.18	Bdl/STK	B	4/N	691.95
AURORA ENERGY LLC	3/7/2014	7	7758	26.72	8.49	35.58	29.20	0.19	Bdl/STK	B	4/N	666.20
AURORA ENERGY LLC	3/10/2014	7	7719	26.52	9.09	35.53	28.86	0.22	Bdl/STK	B	4/N	671.50
AURORA ENERGY LLC	3/11/2014	11	7675	27.64	8.15	35.24	28.97	0.20	Bdl/STK	B	4/N	1,016.05
AURORA ENERGY LLC	3/12/2014	4	7634	27.35	8.82	35.17	28.66	0.21	Bdl/STK	B	4/N	394.50
AURORA ENERGY LLC	3/13/2014	16	7120	26.15	14.55	33.06	26.25	0.25	Bdl/STK	B	4/N	1,555.45
AURORA ENERGY LLC	3/14/2014	12	7615	27.55	9.03	34.97	28.45	0.18	Bdl/STK	B	4/N	1,178.10
AURORA ENERGY LLC	3/17/2014	3	7872	26.97	7.37	36.05	29.62	0.18	Bdl	B	4	281.15
AURORA ENERGY LLC	3/18/2014	12	7750	27.82	7.64	34.83	29.70	0.16	Bdl/STK	B	4/N	1,093.55
AURORA ENERGY LLC	3/19/2014	12	7798	27.45	7.40	35.78	29.38	0.18	Bdl/STK	B	4/N	1,128.70
AURORA ENERGY LLC	3/20/2014	10	7948	26.46	7.32	36.57	29.84	0.23	Bdl/STK	B	4/N	951.45
AURORA ENERGY LLC	3/21/2014	12	7916	27.92	6.00	35.87	30.22	0.12	Bdl	B	4	1,075.20
AURORA ENERGY LLC	3/24/2014	12	7882	27.38	6.81	35.69	15.13	0.14	Bdl/STK	B	4/N	1,043.95
AURORA ENERGY LLC	3/25/2014	1	8057	26.46	6.27	36.20	31.04	0.13	Bdl/STK	B	4/N	85.90
AURORA ENERGY LLC	3/26/2014	15	7887	27.68	6.78	35.65	29.90	0.12	Bdl/T II	B/X3	4/3	1,414.80
AURORA ENERGY LLC	3/27/2014	26	7482	27.96	9.07	34.76	28.21	0.11	TII	X3	3	2,390.75
AURORA ENERGY LLC	3/31/2014	8	7310	27.68	11.54	33.38	27.41	0.13	T II	X3	3	783.60
AURORA ENERGY LLC	4/1/2014	9	7832	28.80	5.23	35.61	30.37	0.10	Bdl	A	3	825.10
AURORA ENERGY LLC	4/2/2014	13	7776	28.29	5.87	35.47	30.37	0.11	Bdl/STK	A	3/N	1,226.70
AURORA ENERGY LLC	4/3/2014	9	7549	27.52	8.97	34.22	29.30	0.13	Bdl/STK	A	3/N	892.80

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	4/4/2014	5	7695	28.07	7.91	34.98	29.05	0.11	T II/Bdl	X3/A	3/3	486.30
AURORA ENERGY LLC	4/7/2014	10	7899	28.09	5.97	35.24	30.71	0.12	Bdl	A	3	913.65
AURORA ENERGY LLC	4/8/2014	10	7861	28.29	6.32	34.97	30.43	0.12	Bdl/STK	A	3/N	951.00
AURORA ENERGY LLC	4/9/2014	14	7878	27.84	6.59	35.28	30.30	0.12	Bdl/STK	A	3/N	1,358.65
AURORA ENERGY LLC	4/10/2014	13	7734	28.36	7.47	34.44	29.73	0.12	Bdl/STK	A	3/N	1,286.85
AURORA ENERGY LLC	4/11/2014	9	7609	28.55	8.22	34.50	28.74	0.12	Bdl/STK	A	3/N	866.30
AURORA ENERGY LLC	4/14/2014	10	7769	27.99	7.38	34.83	29.80	0.11	Bdl/STK	A	3/N	938.10
AURORA ENERGY LLC	4/15/2014	12	7662	28.55	7.20	36.80	27.46	0.13	T II	LST	6	1,108.05
AURORA ENERGY LLC	4/16/2014	11	7262	27.55	11.33	35.30	25.83	0.13	T II	LST	6	950.55
AURORA ENERGY LLC	4/17/2014	13	7462	28.02	9.11	36.75	26.14	0.10	TII	LST	6	1,131.00
AURORA ENERGY LLC	4/18/2014	13	7632	29.53	4.91	36.14	29.42	0.07	Bdl/STK	A	3/N	1,247.60
AURORA ENERGY LLC	4/21/2014	9	7627	27.72	7.25	35.32	29.71	0.11	Bdl/STK	B	3/N	832.25
AURORA ENERGY LLC	4/22/2014	11	7451	27.99	9.12	35.47	27.43	0.13	T II	LST	6	1,070.80
AURORA ENERGY LLC	4/23/2014	11	7525	28.07	8.16	35.70	28.07	0.12	Bdl/STK	B	3/N	999.30
AURORA ENERGY LLC	4/24/2014	12	7570	28.32	8.11	36.21	27.36	0.12	T II	LST	6	1,162.05
AURORA ENERGY LLC	4/25/2014	13	7464	28.40	8.61	36.49	26.51	0.13	TII	LST	6	1,204.30
AURORA ENERGY LLC	4/28/2014	11	7451	27.57	9.55	35.68	27.20	0.13	T II	LST	6	1,083.20
AURORA ENERGY LLC	4/30/2014	12	7397	27.69	9.76	36.58	25.97	0.12	TII	LST	6	1,093.95
AURORA ENERGY LLC	5/1/2014	12	7464	27.86	9.03	36.29	26.82	0.13	TII	LST	6	1,094.60
AURORA ENERGY LLC	5/5/2014	11	7601	28.24	8.15	36.22	27.39	0.14	T II	LST	6	994.65
AURORA ENERGY LLC	5/6/2014	10	7735	27.79	7.63	36.55	28.04	0.14	T II	LST	6	906.90
AURORA ENERGY LLC	5/7/2014	12	7638	28.23	7.46	36.83	27.49	0.13	T II	LST	6	1,121.35
AURORA ENERGY LLC	5/8/2014	14	7544	28.57	8.21	35.22	28.00	0.13	T II/Bsl	LST/A	6/3	1,403.70
AURORA ENERGY LLC	5/12/2014	16	7796	27.50	8.05	35.31	29.14	0.13	Bdl/STK	A	3/N	1,548.15
AURORA ENERGY LLC	5/14/2014	12	7746	28.25	6.78	37.35	27.62	0.12	Bdl/TII	A/LST	3/6	1,055.15
AURORA ENERGY LLC	5/15/2014	9	7712	28.25	7.12	37.35	27.28	0.12	Bdl/TII	A/LST	3/6	858.05
AURORA ENERGY LLC	5/16/2014	10	7707	27.99	7.76	36.08	28.18	0.11	TII/Bdl	LST/A	6/3	974.80
AURORA ENERGY LLC	5/19/2014	8	7769	26.93	7.92	35.48	29.68	0.13	TII/Bdl	LST/B	6/3	769.15
AURORA ENERGY LLC	5/20/2014	11	7915	28.22	6.07	35.62	30.10	0.11	Bdl/STK	B	3/N	1,041.70
AURORA ENERGY LLC	5/21/2014	9	7761	27.26	8.12	35.07	29.56	0.12	Bdl/STK	B	3/N	891.85
AURORA ENERGY LLC	5/22/2014	7	7809	27.38	7.27	35.93	29.43	0.11	Bdl/STK	B	3/N	693.85
AURORA ENERGY LLC	5/23/2014	8	7726	28.33	6.92	38.24	26.52	0.12	TII	LST	6	724.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	5/26/2014	7	7723	28.31	6.78	38.02	26.90	0.12	TII	LST	6	614.05
AURORA ENERGY LLC	5/28/2014	14	7654	26.98	8.94	35.73	28.36	0.12	Bdl/STK	B	3/N	1,342.05
AURORA ENERGY LLC	5/29/2014	12	7514	27.86	9.02	34.63	28.50	0.13	Bdl/STK	B	3/N	1,174.15
AURORA ENERGY LLC	5/30/2014	12	7673	27.44	8.50	34.98	29.08	0.11	Bdl/STK	B	3/N	1,150.20
AURORA ENERGY LLC	6/2/2014	8	7688	27.53	8.31	34.79	29.39	0.11	Bdl/STK	B	3/N	793.70
AURORA ENERGY LLC	6/3/2014	8	7949	27.23	6.72	36.14	29.91	0.11	Bdl/STK	B	3/N	779.60
AURORA ENERGY LLC	6/5/2014	13	7690	28.12	7.45	36.87	27.56	0.13	T II	LST	6	1,236.80
AURORA ENERGY LLC	6/9/2014	5	7676	28.30	7.60	36.90	27.20	0.12	T II	LST	6	481.65
AURORA ENERGY LLC	6/11/2014	7	7704	26.60	10.00	35.94	27.47	0.14	T II/GRP	LST	6/M	683.90
AURORA ENERGY LLC	6/12/2014	5	7669	27.41	8.70	37.27	26.62	0.11	GRP/TII	LST	M/6	489.40
AURORA ENERGY LLC	6/16/2014	10	7632	27.40	8.88	36.76	26.96	0.12	T II	LST	6	964.10
AURORA ENERGY LLC	6/18/2014	16	7672	27.62	7.90	37.02	27.47	0.12	T II	LST	6	1,534.80
AURORA ENERGY LLC	6/19/2014	18	7458	27.53	9.65	36.66	26.16	0.11	TII	LST	6	1,681.40
AURORA ENERGY LLC	6/23/2014	9	7311	28.02	10.34	35.77	25.87	0.15	T II	LST	6	867.60
AURORA ENERGY LLC	6/24/2014	10	7712	27.76	8.03	34.70	29.51	0.12	Bdl/STK	C	3/N	931.05
AURORA ENERGY LLC	6/25/2014	13	7751	28.21	7.20	34.95	29.64	0.11	Bdl/STK	C	3/N	1,259.45
AURORA ENERGY LLC	6/26/2014	12	7776	27.04	7.86	35.66	29.45	0.11	Bdl/STK	C	3/N	1,172.35
AURORA ENERGY LLC	6/30/2014	9	7695	28.75	7.46	34.73	29.06	0.11	Bdl/STK	C	3/N	829.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	117659.65	7652.00	27.89	8.15	35.29	28.54	0.15

This analysis is representative of the coal shipped using sulfur standard ASTM D4239 - 12

Colleen Thompson
7-2-14

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2014	17	7525	28.93	8.28	34.19	28.60	0.12	Bdl/STK	C	3/N	1,638.75
AURORA ENERGY LLC	7/2/2014	11	7442	29.33	8.64	34.80	27.23	0.13	Bdl/STK	C	3/N	1,079.80
AURORA ENERGY LLC	7/4/2014	7	7656	27.98	8.07	36.98	26.97	0.11	TII	LST	6	627.85
AURORA ENERGY LLC	7/7/2014	13	7622	28.13	7.79	37.11	26.97	0.12	T II	LST	6	1,239.90
AURORA ENERGY LLC	7/9/2014	33	7578	28.14	8.43	36.77	26.67	0.13	T II	LST	6	3,141.00
AURORA ENERGY LLC	7/14/2014	13	7395	27.68	9.60	36.03	26.72	0.13	T II	LST	6	1,276.45
AURORA ENERGY LLC	7/16/2014	18	7619	28.26	7.73	36.94	27.08	0.12	T II	LST	6	1,699.05
AURORA ENERGY LLC	7/17/2014	18	7570	28.11	8.29	36.76	26.84	0.12	T II	LST	6	1,778.65
AURORA ENERGY LLC	7/21/2014	14	7442	28.16	9.30	36.11	26.43	0.13	T II	LST	6	1,346.20
AURORA ENERGY LLC	7/23/2014	16	7409	28.35	9.31	36.18	26.16	0.12	T II	LST	6	1,446.00
AURORA ENERGY LLC	7/24/2014	17	7621	27.21	8.61	37.30	26.88	0.11	TII	LST	6	1,544.95
AURORA ENERGY LLC	7/28/2014	5	7539	27.66	8.85	36.81	26.69	0.12	T II	LST	6	490.95
AURORA ENERGY LLC	7/30/2014	6	7675	26.58	9.28	36.70	27.45	0.14	Bdl	C1	6	569.15
AURORA ENERGY LLC	8/4/2014	8	7404	29.01	8.95	35.65	26.39	0.13	T II	LST	6	795.30
AURORA ENERGY LLC	8/5/2014	8	7750	27.08	8.18	37.34	27.40	0.13	TBR	C1	6	703.80
AURORA ENERGY LLC	8/6/2014	17	7586	26.84	9.66	36.79	26.71	0.14	TBR	C1	6	1,686.45
AURORA ENERGY LLC	8/7/2014	13	7425	27.57	10.25	36.28	25.91	0.13	TBR	C1	6	1,299.70
AURORA ENERGY LLC	8/11/2014	8	7702	27.08	8.56	36.95	27.42	0.13	TBR	C1	6	781.45
AURORA ENERGY LLC	8/13/2014	18	7601	26.69	9.52	36.64	27.16	0.13	TBR	C1	6	1,605.50
AURORA ENERGY LLC	8/14/2014	16	7510	26.42	10.35	36.71	26.53	0.12	TBR	C1	6	1,500.05
AURORA ENERGY LLC	8/16/2014	10	7952	25.09	10.53	36.52	27.87	0.19	GRP/STK		M/N	937.00
AURORA ENERGY LLC	8/18/2014	4	7846	25.81	10.48	35.39	28.33	0.17	GRP/STK		M/N	403.90
AURORA ENERGY LLC	8/20/2014	5	7972	25.66	10.21	34.89	29.25	0.16	GRP/STK		M/N	479.00
AURORA ENERGY LLC	8/21/2014	5	7947	25.16	10.86	35.53	28.45	0.16	GRP/STK		M/N	472.20
AURORA ENERGY LLC	8/25/2014	6	7585	26.17	11.19	35.79	26.86	0.14	GRP/STK		M/N	575.15
AURORA ENERGY LLC	8/27/2014	5	7844	26.46	9.73	35.49	28.33	0.15	GRP/STK		M/N	459.95
AURORA ENERGY LLC	8/28/2014	5	7573	27.55	9.51	35.82	27.13	0.13	TBR	C1	6	453.20
AURORA ENERGY LLC	9/2/2014	5	7853	25.68	10.15	35.75	28.43	0.16	GRP/STK		M/N	444.10
AURORA ENERGY LLC	9/3/2014	7	7595	27.30	9.44	35.06	28.21	0.23	Bdl	E	4	599.15
AURORA ENERGY LLC	9/5/2014	9	7114	24.06	18.70	32.49	24.76	0.24	GRP/STK		M/N	804.25

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	9/5/2014	3	7828	23.73	14.19	34.29	27.79	0.22	GRP/STK		M/N	268.65
AURORA ENERGY LLC	9/5/2014	6	7651	23.59	15.37	33.86	27.19	0.23	GRP/STK		M/N	539.60
AURORA ENERGY LLC	9/8/2014	6	7455	27.39	10.16	36.70	25.75	0.13	Bdl	E	4	535.55
AURORA ENERGY LLC	9/10/2014	12	7336	28.02	10.03	35.87	26.09	0.13	T II	LST	6	1,100.05
AURORA ENERGY LLC	9/11/2014	10	7155	27.65	12.33	34.95	25.08	0.13	T II	LST	6	941.35
AURORA ENERGY LLC	9/15/2014	5	7517	27.42	9.62	35.72	27.25	0.17	Bdl	E	4	464.40
AURORA ENERGY LLC	9/17/2014	7	7531	27.52	9.06	36.59	26.84	0.13	T II	LST	6	652.45
AURORA ENERGY LLC	9/18/2014	6	7493	27.99	8.91	35.72	27.39	0.19	T II	LST	6	539.45
AURORA ENERGY LLC	9/22/2014	5	7793	28.38	6.50	35.62	29.51	0.14	Bdl	E	4	481.40
AURORA ENERGY LLC	9/24/2014	9	7206	26.90	12.00	35.04	26.07	0.13	T II	LST	6	864.35
AURORA ENERGY LLC	9/25/2014	10	7528	28.00	8.47	36.92	26.61	0.12	TII	LST	6	971.75
AURORA ENERGY LLC	9/27/2014	11	7739	28.34	6.81	36.34	28.51	0.18	Bdl	E	4	1,007.10
AURORA ENERGY LLC	9/29/2014	11	7739	28.09	6.87	35.86	29.18	0.19	Bdl	F	4	1,034.60
AURORA ENERGY LLC	9/30/2014	11	7749	28.54	6.60	35.47	29.41	0.16	Bdl	F	4	984.35
AURORA ENERGY LLC	10/1/2014	26	7815	28.29	6.55	35.84	29.32	0.16	Bdl	F	4	2,485.80
AURORA ENERGY LLC	10/6/2014	10	7591	28.11	8.20	36.05	27.65	0.16	Bdl/TII	F/LST	4/6	856.70
AURORA ENERGY LLC	10/8/2014	9	7403	27.49	10.14	35.31	27.07	0.16	Bdl/T II	F/LST	4/6	810.80
AURORA ENERGY LLC	10/8/2014	11	7499	28.23	8.70	36.11	26.96	0.12	T II	LST	6	985.90
AURORA ENERGY LLC	10/9/2014	12	7495	28.17	8.40	36.91	26.52	0.12	T II	LST	6	1,116.25
AURORA ENERGY LLC	10/11/2014	13	7566	28.43	7.85	38.08	25.65	0.12	T II	LST	6	1,133.10
AURORA ENERGY LLC	10/13/2014	7	7405	27.91	9.44	36.23	26.43	0.13	T II	LST	6	676.50
AURORA ENERGY LLC	10/15/2014	11	7971	26.15	9.33	35.38	29.13	0.15	GRP/STK		M/N	997.30
AURORA ENERGY LLC	10/16/2014	16	8040	25.93	8.50	36.45	29.13	0.16	GRP/STK		M/N	1,476.75
AURORA ENERGY LLC	10/20/2014	9	7629	27.68	8.84	36.03	27.45	0.14	T II	LST	6	864.20
AURORA ENERGY LLC	10/21/2014	12	7874	27.45	7.56	35.30	29.69	0.13	Bdl	D	3	1,113.15
AURORA ENERGY LLC	10/22/2014	15	7932	27.59	6.48	35.31	30.62	0.12	Bdl	E	3	1,424.60
AURORA ENERGY LLC	10/23/2014	14	7880	27.56	6.24	36.02	30.19	0.10	Bdl	E	3	1,343.80
AURORA ENERGY LLC	10/24/2014	9	7169	30.71	6.85	34.67	27.79	0.12	Jumbo			783.45
AURORA ENERGY LLC	10/27/2014	12	7748	28.04	7.14	35.35	29.47	0.13	Bdl/STK	D	3/N	1,187.15
AURORA ENERGY LLC	10/28/2014	10	7616	28.45	7.79	35.64	28.13	0.12	Bdl/T II	D/LST	3/6	922.05
AURORA ENERGY LLC	10/29/2014	10	7494	28.14	8.94	35.97	26.95	0.13	T II	LST	6	939.80
AURORA ENERGY LLC	10/30/2014	11	7481	28.62	8.07	36.53	26.15	0.12	TII	LST	6	1,074.40

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	10/31/2014	10	7754	28.43	7.39	36.13	28.06	0.13	Tll/Bdl	LST/D	6/3	943.50
AURORA ENERGY LLC	11/3/2014	6	7675	29.16	6.72	34.86	29.26	0.12	Bdl/JD	D	3/4	566.40
AURORA ENERGY LLC	11/4/2014	13	7741	28.44	6.73	35.24	29.59	0.11	Bdl/JD	D	3/4	1,279.15
AURORA ENERGY LLC	11/5/2014	12	7651	28.22	7.68	35.38	28.73	0.12	Bdl/JD	D	3/4	1,176.25
AURORA ENERGY LLC	11/6/2014	9	7622	28.67	7.42	34.84	29.07	0.12	Bdl/JD	D	3/4	848.35
AURORA ENERGY LLC	11/7/2014	12	7769	28.00	7.20	35.32	29.48	0.11	Bdl/JD	D	3/4	1,064.60
AURORA ENERGY LLC	11/10/2014	7	7769	28.21	6.77	35.31	29.71	0.10	Bdl/JD	D	3/4	650.70
AURORA ENERGY LLC	11/11/2014	12	7739	28.65	6.64	35.20	29.52	0.11	Bdl/JD	D	3/4	1,141.50
AURORA ENERGY LLC	11/12/2014	12	7644	29.46	6.67	34.68	29.19	0.12	Bdl/JD	D	3/4	1,120.25
AURORA ENERGY LLC	11/13/2014	9	7613	29.14	6.79	35.81	28.27	0.11	Bdl/JD	D	3/4	840.50
AURORA ENERGY LLC	11/14/2014	7	7805	27.58	7.75	36.16	28.52	0.14	Bdl/JD	D	3/4	638.10
AURORA ENERGY LLC	11/17/2014	6	7749	26.36	10.84	34.65	28.16	0.19	GRP/STK		M/N	604.55
AURORA ENERGY LLC	11/18/2014	31	7295	26.35	14.74	33.00	25.91	0.17	GRP/STK		M/N	3,113.25
AURORA ENERGY LLC	11/19/2014	12	7822	25.92	11.05	34.90	28.14	0.17	GRP/Bdl	D	M/3	1,161.75
AURORA ENERGY LLC	11/21/2014	4	7765	27.96	9.54	34.70	27.80	0.14	GRP/JD		M/4	355.30
AURORA ENERGY LLC	11/24/2014	9	7821	29.00	5.59	36.00	29.41	0.11	Bdl/JD	F	3/4	792.50
AURORA ENERGY LLC	11/25/2014	12	7837	28.38	5.94	35.63	30.05	0.10	Bdl/JD	F	3/4	1,101.60
AURORA ENERGY LLC	11/26/2014	13	7636	29.62	6.57	35.03	28.79	0.09	Bdl/JD	D	3/4	1,157.55
AURORA ENERGY LLC	11/28/2014	9	7798	28.82	6.04	35.55	29.58	0.09	Bdl/JD	F	3/4	775.45
AURORA ENERGY LLC	12/1/2014	8	7814	28.53	6.40	35.39	29.68	0.10	Bdl/STK	F	3/N	742.55
AURORA ENERGY LLC	12/2/2014	11	7843	27.99	6.73	35.16	30.13	0.11	Bdl/STK	F	3/N	1,039.75
AURORA ENERGY LLC	12/3/2014	10	7718	28.26	7.17	35.07	29.51	0.10	Bdl/STK	F	3/N	862.65
AURORA ENERGY LLC	12/4/2014	8	7659	27.93	7.94	35.42	28.71	0.10	Bdl/STK	F	3/N	753.20
AURORA ENERGY LLC	12/5/2014	13	7660	27.86	8.23	35.41	28.51	0.12	Bdl/STK	F	3/N	1,222.65
AURORA ENERGY LLC	12/8/2014	11	7399	26.38	12.62	34.16	26.85	0.31	Bdl/STK	G	4/N	1,068.05
AURORA ENERGY LLC	12/9/2014	10	7758	27.16	8.46	35.76	28.61	0.25	Bdl/STK	G	4/N	933.35
AURORA ENERGY LLC	12/10/2014	8	7671	27.12	8.79	35.30	28.79	0.23	Bdl/STK	G	4/N	730.55
AURORA ENERGY LLC	12/11/2014	9	7762	27.40	8.01	35.48	29.12	0.21	Bdl/Bdl	G/F	4/3	846.70
AURORA ENERGY LLC	12/12/2014	14	7657	27.61	8.26	35.28	28.85	0.15	Bdl/STK	F	3/N	1,285.70
AURORA ENERGY LLC	12/15/2014	12	7491	29.18	8.10	35.28	27.44	0.15	Bdl/JD	G	4/4	1,100.15
AURORA ENERGY LLC	12/16/2014	18	7630	28.23	8.32	35.71	27.74	0.19	Bdl/JD	G	4/4	1,705.05
AURORA ENERGY LLC	12/17/2014	8	[illegible]	[illegible]	[illegible]	[illegible]	28.40	0.16	Bdl/JD	G	4/4	770.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	12/18/2014	20	7528	31.48	6.44	34.37	27.71	0.13	JD		4	1,850.00
AURORA ENERGY LLC	12/19/2014	4	7626	28.89	7.57	35.42	28.12	0.15	Bdl/JD	G	4/4	372.05
AURORA ENERGY LLC	12/22/2014	10	7561	28.72	8.34	35.26	27.69	0.18	Bdl/JD	G	4/4	981.45
AURORA ENERGY LLC	12/23/2014	17	7598	28.65	8.05	35.35	27.95	0.18	Bdl/JD	G	4/4	1,535.65
AURORA ENERGY LLC	12/24/2014	12	7563	28.54	8.75	35.22	27.50	0.19	Bdl/JD	G	4/4	1,037.65
AURORA ENERGY LLC	12/26/2014	6	7418	26.62	12.03	34.98	26.37	0.28	Bdl/JD	G	4/4	550.45
AURORA ENERGY LLC	12/29/2014	8	7385	27.89	10.46	34.77	26.89	0.25	Bdl/JD	G	4/4	778.85
AURORA ENERGY LLC	12/30/2014	12	7568	29.02	8.07	34.65	28.26	0.21	Bdl/JD	G	4/4	1,145.15
AURORA ENERGY LLC	12/31/2014	10	7643	29.27	7.21	35.29	28.24	0.18	Bdl/JD	G	4/4	880.85

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103979.45	7617.00	27.86	8.67	35.66	27.82	0.14

This analysis is representative of the coal shipped using sulfur ASTM D4239-12

Colleen Thompson
1-5-15

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2015	10	7542	28.10	8.78	35.14	27.98	0.22	Bdl/JD	G	4/4	913.35
AURORA ENERGY LLC	1/5/2015	8	7586	29.30	7.87	34.51	28.33	0.21	Bdl/JD	G	4/4	761.95
AURORA ENERGY LLC	1/6/2015	15	7593	29.68	7.16	34.84	28.32	0.21	Bdl/JD	G	4/4	1,331.30
AURORA ENERGY LLC	1/7/2015	10	7609	29.88	6.82	34.57	28.74	0.19	Bdl/JD	G	4/4	913.10
AURORA ENERGY LLC	1/8/2015	13	7572	27.19	9.58	35.09	28.15	0.24	Bdl/JD	G	4/4	1,217.90
AURORA ENERGY LLC	1/9/2015	13	7658	28.66	7.66	35.64	28.04	0.20	Bdl/JD	G	4/4	1,270.65
AURORA ENERGY LLC	1/12/2015	8	7612	27.19	9.36	35.22	28.24	0.22	Bdl/ T II	G/LST	4/6	735.75
AURORA ENERGY LLC	1/13/2015	13	7605	27.86	8.81	35.00	28.33	0.21	Bdl/T II	G/LST	4/6	1,249.40
AURORA ENERGY LLC	1/14/2015	30	7355	26.04	12.63	34.27	27.07	0.31	Bdl/STK	G	4/N	2,906.30
AURORA ENERGY LLC	1/14/2015	10	7413	26.77	11.28	34.53	27.42	0.30	Bdl/STK	G	4/N	985.30
AURORA ENERGY LLC	1/19/2015	8	7722	27.69	7.86	35.65	28.80	0.15	Bdl/STK	G	4/N	710.60
AURORA ENERGY LLC	1/20/2015	13	7615	28.20	7.93	36.17	27.71	0.15	TII/STK	LST	6/N	1,225.25
AURORA ENERGY LLC	1/21/2015	10	7493	27.67	9.57	36.02	26.75	0.14	T II	LST	6	954.30
AURORA ENERGY LLC	1/22/2015	8	7625	27.33	8.98	35.40	28.28	0.22	Bdl/STK	G	4/N	778.30
AURORA ENERGY LLC	1/26/2015	9	7635	27.97	7.73	35.95	28.36	0.15	Bdl/T II	F/LST	3/6	835.50
AURORA ENERGY LLC	1/27/2015	7	7516	28.18	8.81	36.32	26.69	0.14	T II	LST	6	645.20
AURORA ENERGY LLC	1/28/2015	5	7469	28.31	9.15	36.13	26.41	0.15	T II	LST	6	448.45
AURORA ENERGY LLC	1/29/2015	6	7515	28.38	8.44	36.63	26.56	0.13	TII	LST	6	554.05
AURORA ENERGY LLC	1/29/2015	5	7607	28.03	8.04	36.88	27.05	0.13	TII	LST	6	424.60
AURORA ENERGY LLC	1/30/2015	14	7541	28.33	8.44	37.02	26.22	0.13	TII	LST	6	1,209.20
AURORA ENERGY LLC	2/2/2015	9	7551	28.26	8.55	36.52	26.67	0.14	TII	LST	6	834.90
AURORA ENERGY LLC	2/3/2015	31	7078	28.44	12.14	34.70	24.73	0.15	T II	LST	6	2,869.90
AURORA ENERGY LLC	2/3/2015	11	7036	27.65	12.98	35.06	24.32	0.14	T II	LST	6	969.85
AURORA ENERGY LLC	2/4/2015	12	7065	28.03	12.16	34.62	25.20	0.15	T II	LST	6	1,138.45
AURORA ENERGY LLC	2/9/2015	9	7620	27.91	7.79	35.30	29.02	0.13	Bdl/JD	F	3/4	742.75
AURORA ENERGY LLC	2/10/2015	14	7917	27.82	5.80	35.90	30.48	0.12	Bdl/JD	F	3/4	1,277.15
AURORA ENERGY LLC	2/11/2015	8	7702	29.02	6.64	35.33	29.02	0.12	Bdl/JD	F	3/4	680.85
AURORA ENERGY LLC	2/12/2015	6	7618	28.59	7.59	35.98	27.84	0.12	Bdl/JD	F	3/4	525.70
AURORA ENERGY LLC	2/13/2015	8	7614	29.50	7.11	35.67	27.72	0.12	Bdl/JD	F	3/4	674.15
AURORA ENERGY LLC	2/16/2015	8	7681	29.80	6.49	35.97	27.74	0.11	T II/JD	LST	6/4	716.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	2/17/2015	10	7645	30.40	6.24	35.65	27.71	0.12	JD		4	871.10
AURORA ENERGY LLC	2/18/2015	9	7411	30.93	6.97	34.84	27.27	0.13	T II/JD	LST	6/4	775.50
AURORA ENERGY LLC	2/19/2015	10	7474	29.85	7.43	36.13	26.59	0.12	JD/T II	LST	4/6	893.10
AURORA ENERGY LLC	2/20/2015	12	7556	30.19	6.65	36.82	26.35	0.12	T II/JD	LST	6/4	1,087.75
AURORA ENERGY LLC	2/23/2015	8	7490	30.65	6.82	35.48	27.06	0.13	T II/JD	LST	6/4	756.30
AURORA ENERGY LLC	2/24/2015	11	7576	29.59	7.24	35.95	27.22	0.14	JD/TII	LST	4/6	975.50
AURORA ENERGY LLC	2/25/2015	11	7551	29.41	7.42	35.92	27.25	0.13	T II/JD	LST	6/4	1,033.85
AURORA ENERGY LLC	2/26/2015	11	7582	29.74	6.75	36.28	27.23	0.12	T II/JD	LST	6/4	1,003.80
AURORA ENERGY LLC	2/27/2015	11	7588	29.97	6.61	36.05	27.37	0.12	TII/JD	LST	6/4	1,039.00
AURORA ENERGY LLC	3/2/2015	8	7571	29.92	6.43	36.02	27.64	0.12	TII/JD	LST	6/4	730.55
AURORA ENERGY LLC	3/3/2015	10	7698	29.84	5.91	36.58	27.67	0.11	TII/JD	LST	6/4	910.05
AURORA ENERGY LLC	3/4/2015	4	7547	30.62	6.34	35.70	27.34	0.11	TII/JD	LST	6/4	356.15
AURORA ENERGY LLC	3/5/2015	10	7705	29.51	6.01	36.35	28.13	0.11	TII/JD	LST	6/4	927.65
AURORA ENERGY LLC	3/6/2015	11	7662	30.66	5.49	36.26	27.60	0.11	TII/JD	LST	6/4	1,032.00
AURORA ENERGY LLC	3/10/2015	6	7505	30.34	6.76	36.30	26.60	0.11	TII/JD	LST	6/4	549.70
AURORA ENERGY LLC	3/11/2015	26	7109	31.44	7.90	34.89	25.76	0.10	TII/JD	LST	6/4	2,416.95
AURORA ENERGY LLC	3/12/2015	7	7483	29.94	7.34	35.71	27.02	0.11	TII/JD	LST	6/4	620.10
AURORA ENERGY LLC	3/16/2015	4	7525	29.76	7.33	35.86	27.05	0.14	TII/JD	LST	6/4	370.10
AURORA ENERGY LLC	3/17/2015	5	7468	30.08	7.36	35.59	26.98	0.11	TII/JD	LST	6/4	463.30
AURORA ENERGY LLC	3/18/2015	12	7545	30.21	6.84	35.43	27.53	0.12	TII/JD	LST	6/4	1,088.95
AURORA ENERGY LLC	3/19/2015	12	7549	29.60	7.58	35.96	26.86	0.14	TII/JD	LST	6/4	1,105.10
AURORA ENERGY LLC	3/20/2015	7	7620	29.93	7.00	36.02	27.06	0.12	TII/JD	LST	6/4	680.20
AURORA ENERGY LLC	3/23/2015	5	7555	29.89	6.88	35.98	27.26	0.12	TII/JD	LST	6/4	453.55
AURORA ENERGY LLC	4/2/2015	7	7727	30.71	5.38	35.08	28.84	0.12	JD		4	641.55
AURORA ENERGY LLC	4/6/2015	10	7763	31.03	4.67	35.18	29.13	0.11	JD		4	908.40
AURORA ENERGY LLC	4/7/2015	12	7826	30.95	4.55	35.57	28.93	0.11	JD		4	1,081.35
AURORA ENERGY LLC	4/8/2015	11	7669	31.37	5.35	34.58	28.71	0.11	JD		4	1,022.50
AURORA ENERGY LLC	4/9/2015	13	7561	31.87	5.36	34.64	28.14	0.12	JD		4	1,161.20
AURORA ENERGY LLC	4/10/2015	7	7759	30.74	5.03	35.70	28.54	0.11	JD		4	660.95
AURORA ENERGY LLC	4/13/2015	9	7711	31.37	4.82	34.74	29.07	0.11	JD		4	798.25
AURORA ENERGY LLC	4/14/2015	12	7710	31.37	4.77	35.27	28.60	0.11	JD		4	1,105.30
AURORA ENERGY LLC	4/20/2015	9	7625	30.63	5.99	34.56	28.82	0.09	JD		4	836.95

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	4/21/2015	11	7544	30.03	7.59	33.80	28.58	0.11	JD		4	989.35
AURORA ENERGY LLC	4/22/2015	8	7626	29.64	7.23	34.32	28.81	0.14	Bdl/JD	G	4/4	768.10
AURORA ENERGY LLC	4/27/2015	8	7881	29.30	5.28	35.34	30.09	0.11	JD/Bdl	G	4/3	745.75
AURORA ENERGY LLC	4/28/2015	10	7853	29.01	5.21	35.72	30.06	0.11	Bdl/JD	G	3/4	903.75
AURORA ENERGY LLC	4/29/2015	10	7620	31.74	4.50	35.15	28.61	0.10	JD		4	904.95
AURORA ENERGY LLC	4/30/2015	12	7648	28.84	7.36	34.53	29.28	0.11	Bdl/JD	G	3/4	1,151.95
AURORA ENERGY LLC	5/1/2015	8	7453	31.00	6.78	34.50	27.73	0.10	JD		4	733.95
AURORA ENERGY LLC	5/4/2015	10	7424	31.57	6.35	34.12	27.97	0.12	JD		4	891.35
AURORA ENERGY LLC	5/5/2015	8	7414	31.82	6.59	33.68	27.91	0.11	JD		4	747.95
AURORA ENERGY LLC	5/6/2015	11	7610	30.24	6.28	34.87	28.62	0.11	Bdl/JD	G	3/4	980.55
AURORA ENERGY LLC	5/7/2015	9	7511	31.23	6.16	34.56	28.05	0.11	JD		4	873.00
AURORA ENERGY LLC	5/8/2015	8	7743	29.92	5.94	35.21	28.94	0.12	JD		4	704.65
AURORA ENERGY LLC	5/12/2015	15	7685	29.76	6.46	35.56	28.22	0.11	JD		4	1,411.50
AURORA ENERGY LLC	5/13/2015	15	7530	29.73	7.50	35.02	27.76	0.12	Bdl/JD	G	3/4	1,361.45
AURORA ENERGY LLC	5/14/2015	1	7565	30.33	6.72	34.88	28.08	0.11	JD		4	99.55
AURORA ENERGY LLC	5/18/2015	13	7707	29.87	6.38	35.17	28.58	0.11	JD		4	1,253.45
AURORA ENERGY LLC	5/19/2015	8	7694	30.15	6.19	34.79	28.88	0.11	JD		4	704.35
AURORA ENERGY LLC	5/20/2015	12	7626	30.39	6.33	34.90	28.38	0.12	JD		4	1,155.60
AURORA ENERGY LLC	5/21/2015	12	7494	31.30	6.38	34.44	27.89	0.11	JD		4	1,157.45
AURORA ENERGY LLC	5/23/2015	18	7765	29.51	6.18	35.46	28.85	0.11	JD		4	1,660.70
AURORA ENERGY LLC	5/26/2015	8	7580	29.83	7.16	34.99	28.03	0.12	JD		4	732.30
AURORA ENERGY LLC	5/27/2015	14	7685	28.61	7.56	35.32	28.52	0.12	JD		4	1,376.90
AURORA ENERGY LLC	5/28/2015	14	7626	29.63	6.99	34.90	28.48	0.12	JD		4	1,353.00
AURORA ENERGY LLC	5/29/2015	6	7579	30.41	6.82	34.66	28.11	0.13	JD		4	565.25
AURORA ENERGY LLC	6/1/2015	9	7636	30.25	6.18	35.13	28.44	0.12	JD		4	857.75
AURORA ENERGY LLC	6/2/2015	8	7728	31.26	4.72	35.04	28.98	0.12	JD		4	727.00
AURORA ENERGY LLC	6/3/2015	12	7547	31.16	6.51	33.90	28.44	0.12	JD		4	1,199.65
AURORA ENERGY LLC	6/4/2015	13	7792	30.16	5.50	34.95	29.39	0.12	JD		4	1,262.20
AURORA ENERGY LLC	6/5/2015	13	7703	30.94	5.14	35.45	28.48	0.11	JD		4	1,158.10
AURORA ENERGY LLC	6/8/2015	10	7842	30.61	4.60	35.17	29.63	0.11	JD		4	944.15
AURORA ENERGY LLC	6/9/2015	8	7726	30.82	5.57	34.59	29.03	0.12	JD		4	772.90
AURORA ENERGY LLC	6/10/2015	9	7794	30.29	4.94	35.61	29.16	0.12	JD		4	865.10

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	6/11/2015	2	7952	29.43	5.92	34.72	29.93	0.12	GRP/STK	M/N	194.00
AURORA ENERGY LLC	6/12/2015	11	7855	28.23	7.74	34.69	29.34	0.14	GRP/STK	M/N	1,098.10
AURORA ENERGY LLC	6/15/2015	10	7900	26.99	8.73	35.33	28.95	0.14	GRP/STK	M/N	996.05
AURORA ENERGY LLC	6/16/2015	6	7887	25.37	10.64	35.26	28.73	0.15	GRP/STK	M/N	588.95
AURORA ENERGY LLC	6/17/2015	29	7528	24.32	14.26	34.44	26.99	0.15	GRP/STK	M/N	2,832.55
AURORA ENERGY LLC	6/17/2015	9	7518	24.53	13.61	35.06	26.81	0.15	GRP/STK	M/N	868.65
AURORA ENERGY LLC	6/22/2015	10	7649	28.27	8.58	35.13	28.03	0.13	JD	4	976.50
AURORA ENERGY LLC	6/23/2015	12	7581	28.39	8.07	34.39	29.15	0.13	Bdl	3	1,185.10
AURORA ENERGY LLC	6/24/2015	9	7885	27.12	7.70	35.35	29.83	0.13	Bdl/STK	6/N	861.60
AURORA ENERGY LLC	6/25/2015	8	7813	27.83	6.96	35.60	29.62	0.11	Bdl/STK	3/N	748.55
AURORA ENERGY LLC	6/26/2015	10	8048	26.19	8.73	35.21	29.87	0.15	GRP/STK	M/N	959.85
AURORA ENERGY LLC	6/29/2015	14	8027	26.68	8.75	34.64	29.93	0.15	GRP/STK	M/N	1,393.95
AURORA ENERGY LLC	6/30/2015	14	7934	27.67	7.69	35.54	29.11	0.14	JD	4	1,330.30

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103904.80	7599.00	29.16	7.65	35.23	27.96	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson Date 7-1-15

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/2/2015	5	7689	29.31	7.19	35.30	28.21	0.13	Bdl/GRP	I	3/M	497.30
AURORA ENERGY LLC	7/6/2015	14	7636	28.59	7.92	35.01	28.49	0.15	Bld	I	4	1,372.10
AURORA ENERGY LLC	7/7/2015	14	7874	26.58	7.76	36.94	28.71	0.21	Bdl	I	4	1,382.00
AURORA ENERGY LLC	7/8/2015	3	7865	26.43	7.83	36.21	29.54	0.21	BLD	I	4	316.65
AURORA ENERGY LLC	7/9/2015	8	7770	26.23	8.84	36.65	28.29	0.23	Bdl	I	4	785.95
AURORA ENERGY LLC	7/10/2015	5	7921	25.95	8.00	36.75	29.31	0.19	Bdl	I	4	508.65
AURORA ENERGY LLC	7/13/2015	10	7931	25.76	7.97	36.81	29.47	0.18	Bdl	I	4	979.25
AURORA ENERGY LLC	7/14/2015	10	7750	26.64	8.53	36.28	28.56	0.21	Bdl	I	4	954.80
AURORA ENERGY LLC	7/15/2015	10	7867	26.76	7.54	36.58	29.13	0.21	Bdl	I	4	982.35
AURORA ENERGY LLC	7/16/2015	15	7868	26.59	7.56	36.90	28.95	0.21	Bdl	I	4	1,462.70
AURORA ENERGY LLC	7/17/2015	8	7832	26.21	7.83	37.22	28.75	0.22	Bdl	I	4	765.40
AURORA ENERGY LLC	7/20/2015	8	7860	27.03	7.13	36.27	29.58	0.19	Bdl	I	4	766.65
AURORA ENERGY LLC	7/21/2015	9	7694	27.61	7.96	35.51	28.93	0.20	Bdl/STK	I	4/N	908.35
AURORA ENERGY LLC	7/22/2015	9	7657	29.32	6.95	35.01	28.72	0.15	JD		4	877.65
AURORA ENERGY LLC	7/23/2015	9	7438	30.33	7.55	34.18	27.95	0.12	JD		4	859.90
AURORA ENERGY LLC	7/24/2015	8	7636	29.50	6.86	35.30	28.35	0.11	JD		4	772.45
AURORA ENERGY LLC	7/27/2015	9	7432	31.12	7.58	33.61	27.70	0.13	JD		4	899.50
AURORA ENERGY LLC	7/28/2015	11	7523	30.83	6.76	34.27	28.14	0.12	JD		4	1,073.20
AURORA ENERGY LLC	7/30/2015	7	7425	30.34	7.77	34.10	27.79	0.14	JD		4	693.90
AURORA ENERGY LLC	7/31/2015	8	7734	27.22	7.93	35.90	28.96	0.22	Bdl/Bdl	I/I	3/4	724.30
AURORA ENERGY LLC	8/3/2015	9	7654	28.48	7.69	35.42	28.41	0.16	JD		4	867.75
AURORA ENERGY LLC	8/4/2015	10	7670	29.51	6.73	35.20	28.57	0.14	JD		4	937.50
AURORA ENERGY LLC	8/5/2015	12	7566	30.37	6.67	35.07	27.90	0.13	JD		4	999.75
AURORA ENERGY LLC	8/6/2015	11	7279	30.35	9.11	34.22	26.33	0.14	JD		4	1,037.80
AURORA ENERGY LLC	8/7/2015	11	7368	30.17	8.21	34.20	27.42	0.15	Bdl/JD	I	4/4	1,056.30
AURORA ENERGY LLC	8/10/2015	18	7660	29.39	6.76	35.20	28.65	0.15	JD/Bdl	/I	4/4	1,653.75
AURORA ENERGY LLC	8/12/2015	15	7359	31.58	7.10	33.94	27.40	0.14	JD		4	1,416.85
AURORA ENERGY LLC	8/13/2015	18	7510	30.41	6.79	34.63	28.16	0.17	Bdl/JD	I	4/4	1,775.95
AURORA ENERGY LLC	8/14/2015	15	7733	27.83	7.35	36.00	28.82	0.14	Bdl	I	4	1,397.60
AURORA ENERGY LLC	8/17/2015	10	7663	29.07	7.20	35.01	28.73	0.13	JD		4	943.65

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	8/18/2015	13	7658	28.80	7.07	35.38	28.76	0.16	JD		4	1,265.45
AURORA ENERGY LLC	8/20/2015	15	7311	31.47	7.37	33.83	27.33	0.12	Bdl/JD	I/	3/4	1,386.75
AURORA ENERGY LLC	8/22/2015	18	7564	31.72	6.35	34.30	27.63	0.10	JD		4	1,546.75
AURORA ENERGY LLC	8/26/2015	15	7740	28.52	8.85	34.07	28.56	0.17	JD/GRP		4/M	1,471.40
AURORA ENERGY LLC	8/28/2015	3	7642	28.09	8.57	35.40	27.94	0.15	GPR/Bdl		M/6	261.50
AURORA ENERGY LLC	8/31/2015	8	7628	27.35	8.96	36.33	27.37	0.14	Bdl		6	720.95
AURORA ENERGY LLC	9/1/2015	17	7681	27.34	8.39	36.84	27.43	0.13	Bdl		6	1,651.15
AURORA ENERGY LLC	9/2/2015	19	7563	27.07	9.34	36.51	27.09	0.14	Bdl		6	1,898.00
AURORA ENERGY LLC	9/3/2015	27	7665	27.56	8.27	35.87	28.31	0.13	Bdl		6	2,698.95
AURORA ENERGY LLC	9/8/2015	17	7806	27.29	7.46	35.64	29.61	0.13	Bdl/STK	I/	3/N	1,594.85
AURORA ENERGY LLC	9/10/2015	20	7891	26.52	7.77	35.76	29.97	0.14	Bdl/GRP	I/	3/M	1,863.50
AURORA ENERGY LLC	9/11/2015	21	7710	26.65	9.21	35.53	28.61	0.14	Bdl/GRP	I	3/M	1,974.90
AURORA ENERGY LLC	9/15/2015	18	7420	26.03	13.40	33.43	27.10	0.16	Bdl/GRP	I	3/M	1,735.35
AURORA ENERGY LLC	9/16/2015	17	7697	26.35	10.77	36.32	26.56	0.16	GRP/Bdl		M/6	1,681.25
AURORA ENERGY LLC	9/17/2015	17	7519	26.86	10.99	35.61	26.55	0.16	Bdl/GRP		6/M	1,555.60
AURORA ENERGY LLC	9/22/2015	19	7186	27.11	12.93	34.08	25.88	0.17	Bdl/GRP		6/M	1,877.05
AURORA ENERGY LLC	9/23/2015	18	7544	27.46	9.76	34.45	28.34	0.15	Bdl	I	3	1,812.45
AURORA ENERGY LLC	9/24/2015	6	7573	26.47	10.49	34.19	28.85	0.14	Bdl	I	3	604.35
AURORA ENERGY LLC	9/29/2015	6	7141	28.88	11.36	33.89	25.87	0.15	Bdl/GRP	I	3/M	603.55
AURORA ENERGY LLC	9/30/2015	5	7514	28.44	8.69	34.21	28.66	0.13	Bdl/Bdl	I	3/6	490.85
AURORA ENERGY LLC	10/1/2015	10	7360	29.29	9.35	33.72	27.64	0.14	Bdl/Bdl	I	3/6	949.70
AURORA ENERGY LLC	10/6/2015	17	7434	28.25	9.47	34.75	27.54	0.14	Bdl		6	1,697.60
AURORA ENERGY LLC	10/7/2015	16	7427	28.14	9.75	33.75	28.48	0.13	Bdl/STK	I	3/N	1,590.90
AURORA ENERGY LLC	10/8/2015	16	7766	28.02	6.97	35.04	29.97	0.14	Bdl/STK	I	3/N	1,550.35
AURORA ENERGY LLC	10/12/2015	12	7509	28.74	8.47	34.02	28.77	0.11	Bdl/JD	I	3/4	1,188.55
AURORA ENERGY LLC	10/13/2015	14	7448	29.46	8.57	34.10	27.88	0.11	Bdl/JD	I	3/4	1,378.00
AURORA ENERGY LLC	10/14/2015	15	7329	31.93	7.28	33.16	27.63	0.11	Bdl/JD	I	3/4	1,487.05
AURORA ENERGY LLC	10/15/2015	5	7435	31.66	6.81	34.31	27.23	0.11	JD		4	472.55
AURORA ENERGY LLC	10/16/2015	6	7723	31.20	5.10	35.54	28.17	0.11	JD		4	564.80
AURORA ENERGY LLC	10/20/2015	15	7561	31.93	5.92	34.77	27.38	0.11	JD		4	1,442.25
AURORA ENERGY LLC	10/21/2015	14	7609	31.67	5.47	34.54	28.32	0.11	JD		4	1,346.70
AURORA ENERGY LLC	10/22/2015	13	7492	32.01	6.01	34.29	27.70	0.11	JD		4	1,264.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	10/23/2015	15	7347	32.39	6.71	33.49	27.42	0.12	JD		4	1,492.50
AURORA ENERGY LLC	10/27/2015	9	7404	30.15	8.49	34.36	27.00	0.18	Bdl	J	4	910.80
AURORA ENERGY LLC	10/28/2015	11	7586	30.32	6.73	35.02	27.93	0.14	Bld/JD	J/	4/4	1,018.90
AURORA ENERGY LLC	10/29/2015	9	7861	26.44	7.92	36.05	29.59	0.19	Bdl	J	4	922.55
AURORA ENERGY LLC	10/30/2015	11	7948	26.92	7.00	36.90	29.19	0.17	Bdl	J	4	1,070.45
AURORA ENERGY LLC	11/3/2015	10	7438	27.87	10.34	34.56	27.24	0.28	Bdl/JD	J/	4/4	994.40
AURORA ENERGY LLC	11/4/2015	16	7495	29.67	8.21	34.18	27.95	0.20	Bdl	J	4	1,577.40
AURORA ENERGY LLC	11/5/2015	11	7320	29.67	9.27	33.61	27.46	0.22	Bdl	J	4	1,052.25
AURORA ENERGY LLC	11/6/2015	12	7629	27.60	8.75	35.23	28.42	0.25	Bdl/JD	J/	4/4	1,175.00
AURORA ENERGY LLC	11/10/2015	12	7640	28.50	7.97	35.25	28.29	0.19	Bdl	J	4	1,130.35
AURORA ENERGY LLC	11/11/2015	14	7865	27.22	7.50	35.71	29.58	0.21	Bdl	J	4	1,331.05
AURORA ENERGY LLC	11/12/2015	12	7797	27.25	7.73	35.48	29.54	0.23	Bdl	J	4	1,146.35
AURORA ENERGY LLC	11/13/2015	14	7947	26.11	7.79	36.51	29.60	0.19	Bdl	J	4	1,368.95
AURORA ENERGY LLC	11/17/2015	9	7760	27.53	7.86	35.47	29.14	0.20	Bdl/JD	J/	4/4	848.40
AURORA ENERGY LLC	11/18/2015	11	7705	28.38	7.44	35.64	28.55	0.18	Bdl/JD	J	4/4	1,026.00
AURORA ENERGY LLC	11/19/2015	8	7644	30.78	6.20	34.89	28.13	0.15	Bdl/JD	J	4/4	714.95
AURORA ENERGY LLC	11/20/2015	10	7783	29.27	6.29	35.70	28.73	0.15	JD/Bdl	/J	4/4	863.55
AURORA ENERGY LLC	11/23/2015	11	7793	29.35	6.29	35.57	28.79	0.15	JD		4	1,046.45
AURORA ENERGY LLC	11/24/2015	16	7682	30.62	5.97	34.92	28.49	0.12	JD		4	1,518.80
AURORA ENERGY LLC	11/25/2015	13	7770	29.54	6.19	35.63	28.65	0.14	JD/Bdl	/J	4/4	1,206.80
AURORA ENERGY LLC	11/27/2015	12	7612	28.41	7.98	35.68	27.94	0.19	Bdl/STK	J/	4/N	1,178.80
AURORA ENERGY LLC	12/1/2015	21	7514	29.25	8.35	34.58	27.83	0.20	Bdl/STK	J/	4/N	1,971.15
AURORA ENERGY LLC	12/2/2015	9	7587	30.48	6.72	34.32	28.49	0.16	JD		4	834.10
AURORA ENERGY LLC	12/3/2015	12	7577	32.45	4.74	33.98	28.84	0.10	JD		4	1,097.45
AURORA ENERGY LLC	12/4/2015	10	7503	31.28	6.60	33.78	28.35	0.12	JD		4	915.25
AURORA ENERGY LLC	12/8/2015	13	7594	29.65	7.36	34.53	28.47	0.17	Bdl/JD	J/	4/4	1,204.60
AURORA ENERGY LLC	12/9/2015	13	7627	28.50	8.21	34.71	28.58	0.23	Bdl/JD	J/	4/4	1,254.80
AURORA ENERGY LLC	12/10/2015	12	7651	29.18	7.10	35.18	28.55	0.17	Bdl/JD	J/	4/4	1,090.15
AURORA ENERGY LLC	12/11/2015	10	7159	33.74	6.25	34.17	25.84	0.14	JD		4	935.95
AURORA ENERGY LLC	12/15/2015	14	7591	31.15	5.91	35.16	27.78	0.15	Bdl/JD	J	4/4	1,235.25
AURORA ENERGY LLC	12/16/2015	14	7527	31.73	6.00	35.00	27.27	0.16	Bdl/JD	J	4/4	1,288.80
AURORA ENERGY LLC	12/17/2015	14	7639	29.80	6.85	35.24	28.12	0.16	Bdl/JD	J	4/4	1,258.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	12/18/2015	14	7571	30.68	6.58	34.72	28.03	0.13	Bdl/JD	J	4/4	1,314.95
AURORA ENERGY LLC	12/21/2015	14	7631	30.24	6.30	35.17	28.29	0.15	Bdl/JD	J	4/4	1,318.90
AURORA ENERGY LLC	12/22/2015	14	7549	31.19	5.71	34.71	28.39	0.13	Bdl/JD	J	4/4	1,250.95
AURORA ENERGY LLC	12/23/2015	14	7686	31.43	4.63	35.27	28.68	0.10	Bdl/JD	J	4/4	1,262.70
AURORA ENERGY LLC	12/24/2015	10	7627	31.52	4.92	35.64	27.93	0.11	Bdl/JD	J	4/4	933.25
AURORA ENERGY LLC	12/28/2015	14	7714	30.71	4.93	36.01	28.36	0.11	Bdl/JD	J	4/4	1,246.45
AURORA ENERGY LLC	12/29/2015	16	7780	30.08	5.31	35.97	28.65	0.12	Bdl/JD	J	4/4	1,424.70
AURORA ENERGY LLC	12/30/2015	11	7673	31.40	5.02	35.64	27.95	0.12	Bdl/JD	J	4/4	968.20
AURORA ENERGY LLC	12/31/2015	12	7705	31.63	4.47	35.57	28.34	0.12	Bdl/JD	J	3/4	1,059.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	120758.30	7610.00	29.02	7.69	35.09	28.20	0.15

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 1-7-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/5/2016	12	7673	31.18	4.92	35.22	28.68	0.11	Bdl/JD	J	4/4	1,108.40
AURORA ENERGY LLC	1/6/2016	14	7682	32.31	4.20	34.85	28.65	0.11	JD		4	1,247.50
AURORA ENERGY LLC	1/7/2016	14	7643	32.35	3.60	35.28	28.78	0.09	JD		4	1,202.65
AURORA ENERGY LLC	1/8/2016	12	7757	31.14	4.23	36.17	28.47	0.11	JD		4	1,070.90
AURORA ENERGY LLC	1/12/2016	13	7631	32.21	4.40	35.14	28.22	0.11	Bdl/JD	J	4/4	1,200.75
AURORA ENERGY LLC	1/13/2016	18	7628	32.43	4.12	35.32	28.15	0.09	JD		4	1,613.00
AURORA ENERGY LLC	1/14/2016	14	7958	28.18	4.48	37.67	29.68	0.11	JD		4	1,188.40
AURORA ENERGY LLC	1/15/2016	16	7789	31.38	4.12	36.77	27.74	0.11	JD		4	1,385.20
AURORA ENERGY LLC	1/19/2016	18	7765	31.50	4.26	35.37	28.87	0.10	JD		4	1,604.95
AURORA ENERGY LLC	1/20/2016	16	7842	31.19	4.24	35.66	28.92	0.12	JD		4	1,439.05
AURORA ENERGY LLC	1/21/2016	15	7766	31.45	4.46	35.39	28.71	0.13	JD		4	1,348.85
AURORA ENERGY LLC	1/22/2016	22	7741	31.09	4.62	35.72	28.58	0.11	JD		4	1,962.55
AURORA ENERGY LLC	1/26/2016	14	7416	32.12	6.10	34.25	27.54	0.13	JD		4	1,350.60
AURORA ENERGY LLC	1/27/2016	12	7664	31.19	5.07	35.10	28.65	0.11	Bdl/JD	J	4/4	1,095.55
AURORA ENERGY LLC	1/28/2016	11	7741	31.54	4.52	35.16	28.79	0.10	Bdl/JD	J	4/4	982.50
AURORA ENERGY LLC	1/29/2016	13	7646	31.93	4.34	35.66	28.09	0.10	JD		4	1,140.40
AURORA ENERGY LLC	2/2/2016	12	7569	31.65	5.24	34.87	28.26	0.10	JD/Bdl	/J	4/3	1,088.10
AURORA ENERGY LLC	2/3/2016	13	7695	31.32	4.75	35.02	28.92	0.12	Bdl/JD	J	3/4	1,202.80
AURORA ENERGY LLC	2/4/2016	8	7549	30.72	6.88	34.43	27.98	0.18	Bdl/JD	J	4/4	705.70
AURORA ENERGY LLC	2/5/2016	11	7664	30.92	5.55	35.22	28.31	0.14	JD/Bdl	/J	4/4	998.75
AURORA ENERGY LLC	2/9/2016	14	7572	31.26	6.21	34.69	27.85	0.13	JD		4	1,298.35
AURORA ENERGY LLC	2/10/2016	13	7785	29.54	6.19	35.63	28.65	0.15	Bdl/JD	J	4/4	1,191.45
AURORA ENERGY LLC	2/11/2016	11	7479	31.97	5.48	34.93	27.63	0.14	Bdl/JD	J	4/4	1,023.95
AURORA ENERGY LLC	2/12/2016	15	7576	30.68	5.50	35.74	28.08	0.14	Bdl/JD	J	4/4	1,417.30
AURORA ENERGY LLC	2/16/2016	16	7634	30.60	5.38	36.09	27.93	0.14	JD/Bdl	/J	4/4	1,512.75
AURORA ENERGY LLC	2/17/2016	14	7781	29.69	5.73	35.79	28.79	0.17	Bdl/JD	J	4/4	1,299.10
AURORA ENERGY LLC	2/18/2016	11	7773	30.32	5.11	35.59	28.99	0.14	Bdl/JD	J	4/4	1,016.45
AURORA ENERGY LLC	2/19/2016	16	7808	29.51	5.45	36.18	28.86	0.14	JD/Bdl	/J	4/4	1,465.95
AURORA ENERGY LLC	2/23/2016	21	7926	29.40	4.93	36.36	29.31	0.14	JD		4	1,903.35

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Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	2/24/2016	16	7799	31.52	4.31	35.32	28.85	0.12	Bdl/JD	J	4/4	1,498.15
AURORA ENERGY LLC	2/25/2016	15	7794	31.50	4.13	35.15	29.22	0.10	JD		4	1,324.05
AURORA ENERGY LLC	3/1/2016	12	7806	30.97	4.49	36.14	28.40	0.12	JD		4	1,126.55
AURORA ENERGY LLC	3/2/2016	16	7805	31.54	4.14	35.52	28.80	0.11	JD		4	1,478.45
AURORA ENERGY LLC	3/3/2016	14	7717	32.25	4.14	35.10	28.52	0.11	JD		4	1,295.50
AURORA ENERGY LLC	3/4/2016	16	7828	31.13	4.14	36.06	28.67	0.11	JD		4	1,430.90
AURORA ENERGY LLC	3/8/2016	13	7701	29.55	6.64	34.82	28.99	0.12	JD/Bdl	/J	4/3	1,224.45
AURORA ENERGY LLC	3/9/2016	13	7732	30.28	5.88	34.95	28.89	0.11	JD/Bdl	/J	4/3	1,231.45
AURORA ENERGY LLC	3/15/2016	12	7823	29.23	5.87	35.65	29.26	0.11	JD/Bdl	/J	4/3	1,121.25
AURORA ENERGY LLC	3/16/2016	13	7871	30.17	4.64	35.79	29.39	0.11	JD		4	1,143.60
AURORA ENERGY LLC	3/17/2016	13	7767	28.41	7.14	35.19	29.27	0.12	Bdl/STK	J/	3/	1,222.65
AURORA ENERGY LLC	3/18/2016	14	7766	27.74	7.62	35.37	29.27	0.12	Bdl/STK	J/	3/	1,287.65
AURORA ENERGY LLC	3/22/2016	14	7719	29.44	6.41	35.32	28.84	0.11	Bdl/JD	J/	3/4	1,317.00
AURORA ENERGY LLC	3/23/2016	18	7696	30.24	5.71	34.71	29.36	0.10	Bdl/JD	J	3/4	1,647.95
AURORA ENERGY LLC	3/24/2016	16	7574	32.11	4.93	35.45	27.52	0.10	JD		4	1,413.40
AURORA ENERGY LLC	3/29/2016	12	7716	31.99	4.16	35.71	28.14	0.11	JD		4	1,091.50
AURORA ENERGY LLC	3/30/2016	13	7642	32.31	4.18	35.81	27.70	0.11	JD		4	1,222.60
AURORA ENERGY LLC	3/31/2016	15	7741	31.85	4.24	35.23	28.68	0.11	JD		4	1,385.25
AURORA ENERGY LLC	4/1/2016	12	7723	31.82	4.28	35.95	27.95	0.11	JD		4	1,102.80
AURORA ENERGY LLC	4/5/2016	12	7666	31.80	4.77	35.48	27.95	0.12	JD		4	1,153.20
AURORA ENERGY LLC	4/6/2016	13	7705	31.70	4.66	35.12	28.53	0.12	JD		4	1,206.05
AURORA ENERGY LLC	4/7/2016	12	7602	32.54	4.49	34.80	28.18	0.12	JD		4	1,156.65
AURORA ENERGY LLC	4/8/2016	13	7766	31.23	4.49	36.04	28.25	0.11	JD		4	1,227.00
AURORA ENERGY LLC	4/12/2016	10	7756	31.50	4.66	35.46	28.39	0.12	JD		4	960.30
AURORA ENERGY LLC	4/13/2016	11	7760	31.37	4.62	35.61	28.41	0.12	JD		4	1,069.45
AURORA ENERGY LLC	4/14/2016	9	7733	31.94	4.36	35.32	28.38	0.11	JD		4	854.95
AURORA ENERGY LLC	4/15/2016	9	7768	30.79	4.70	35.74	28.78	0.11	JD		4	839.70
AURORA ENERGY LLC	4/18/2016	12	7810	31.46	4.40	35.85	28.29	0.11	JD		4	1,126.80
AURORA ENERGY LLC	4/19/2016	11	7621	32.18	4.88	34.90	28.05	0.11	JD		4	1,035.05
AURORA ENERGY LLC	4/20/2016	13	7585	32.41	4.90	34.42	28.27	0.10	JD		4	1,274.85

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Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	4/21/2016	12	7648	31.78	4.97	34.64	28.61	0.10	JD		4	1,128.20
AURORA ENERGY LLC	4/25/2016	12	7804	30.65	5.06	35.23	29.07	0.11	JD		4	1,120.80
AURORA ENERGY LLC	4/26/2016	10	7794	30.80	4.83	35.24	29.13	0.10	JD		4	1,017.70
AURORA ENERGY LLC	4/27/2016	13	7792	31.50	4.34	35.33	28.84	0.10	JD		4	1,255.45
AURORA ENERGY LLC	4/28/2016	13	7717	31.14	4.83	35.23	28.80	0.11	JD		4	1,284.75
AURORA ENERGY LLC	5/2/2016	12	7733	31.54	4.44	35.22	28.81	0.10	JD		4	1,168.35
AURORA ENERGY LLC	5/3/2016	12	7747	31.52	4.43	35.40	28.66	0.11	JD		4	1,073.35
AURORA ENERGY LLC	5/9/2016	3	7772	30.90	5.16	34.88	29.06	0.13	JD		4	288.15
AURORA ENERGY LLC	5/10/2016	3	7870	29.71	5.13	36.25	28.91	0.12	JD		4	268.35
AURORA ENERGY LLC	5/11/2016	4	7720	33.22	3.17	34.91	28.70	0.08	JD		4	372.65
AURORA ENERGY LLC	5/13/2016	8	7504	33.43	4.57	34.09	27.91	0.10	JD		4	761.40
AURORA ENERGY LLC	5/17/2016	11	7630	32.79	4.33	34.71	28.17	0.10	JD		4	1,084.05
AURORA ENERGY LLC	5/18/2016	11	7466	34.38	4.30	33.98	27.35	0.10	JD/JD		3/4	1,050.25
AURORA ENERGY LLC	5/19/2016	11	7277	32.62	7.83	33.49	26.07	0.13	JD/JD		3/4	1,127.45
AURORA ENERGY LLC	5/20/2016	12	7552	31.48	6.32	34.89	27.32	0.12	JD/JD		3/4	1,176.40
AURORA ENERGY LLC	5/23/2016	14	7661	31.33	5.63	34.90	28.15	0.12	JD/JD		3/4	1,367.20
AURORA ENERGY LLC	5/24/2016	13	7685	31.62	5.34	35.25	27.80	0.12	JD/JD		3/4	1,229.45
AURORA ENERGY LLC	5/25/2016	13	7492	32.88	5.31	34.79	27.03	0.12	JD/JD		3/4	1,237.80
AURORA ENERGY LLC	5/26/2016	10	7627	31.34	5.59	35.37	27.71	0.13	JD/JD		3/4	996.95
AURORA ENERGY LLC	5/31/2016	13	7730	30.85	5.28	36.10	27.77	0.11	JD		4	1,246.35
AURORA ENERGY LLC	6/1/2016	13	7826	30.81	4.68	36.26	28.26	0.10	JD/JD		4/3	1,188.90
AURORA ENERGY LLC	6/2/2016	12	7791	31.02	4.90	35.82	28.26	0.12	JD/JD		3/4	1,073.70
AURORA ENERGY LLC	6/3/2016	14	7647	28.04	8.54	35.38	28.04	0.21	JD/Bdl	/K	3/4	1,360.65
AURORA ENERGY LLC	6/6/2016	13	7411	30.10	8.84	34.34	26.72	0.23	Bdl/JD	K	4/3	1,274.75
AURORA ENERGY LLC	6/7/2016	11	7464	31.52	6.83	34.18	27.47	0.11	Bdl/JD	K	4/3	1,035.45
AURORA ENERGY LLC	6/8/2016	11	7491	30.78	7.37	34.34	27.51	0.14	Bdl/JD	K	4/3	1,040.50
AURORA ENERGY LLC	6/9/2016	10	7613	30.80	6.31	35.15	27.74	0.13	Bdl/JD	K	4/3	993.00
AURORA ENERGY LLC	6/13/2016	12	7632	31.54	5.50	34.94	28.02	0.12	Bdl/JD		4/3	1,190.00
AURORA ENERGY LLC	6/14/2016	12	7599	31.45	5.87	34.93	27.76	0.12	JD/JD		3/4	1,177.30
AURORA ENERGY LLC	6/16/2016	24	7514	32.67	5.39	35.16	26.78	0.12	JD/JD		3/4	2,323.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	6/20/2016	16	7606	31.88	5.51	35.05	27.57	0.10	JD/JD		3/4	1,578.60
AURORA ENERGY LLC	6/21/2016	16	7641	31.29	6.01	34.95	27.75	0.12	JD/JD		3/4	1,540.35
AURORA ENERGY LLC	6/23/2016	15	7667	31.90	5.11	34.65	28.35	0.12	JD/JD		3/4	1,438.65
AURORA ENERGY LLC	6/27/2016	12	7480	31.07	6.90	34.53	27.50	0.11	JD/JD		3/4	1,109.05
AURORA ENERGY LLC	6/28/2016	11	7637	31.39	5.94	35.68	27.00	0.12	JD/JD		3/4	1,037.70
AURORA ENERGY LLC	6/29/2016	9	7577	30.69	7.06	35.22	27.03	0.13	JD/JD		3/4	863.15
AURORA ENERGY LLC	6/30/2016	13	7574	31.03	6.80	35.12	27.06	0.13	JD/JD		3/4	1,267.15

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
EIELSON AFB - DFAS	1/5/2016	9	7520	31.96	5.18	34.80	28.07	0.12	Bdl/JD	J	4/4	840.80
EIELSON AFB - DFAS	1/6/2016	10	7660	32.32	4.25	34.80	28.64	0.11	JD		4	916.40
EIELSON AFB - DFAS	1/7/2016	10	7724	32.29	3.66	35.34	28.72	0.10	JD		4	908.10
EIELSON AFB - DFAS	1/12/2016	10	7633	32.22	4.49	35.25	28.05	0.12	Bdl/JD	J	4/4	927.90
EIELSON AFB - DFAS	1/13/2016	10	7661	32.66	3.66	35.37	28.32	0.08	JD		4	893.05
EIELSON AFB - DFAS	1/14/2016	10	7709	31.71	4.17	35.75	28.37	0.10	JD		4	888.45
EIELSON AFB - DFAS	1/15/2016	10	7778	31.00	4.60	36.33	28.08	0.12	JD		4	909.15
EIELSON AFB - DFAS	1/19/2016	12	7712	31.80	4.38	35.14	28.68	0.10	JD		4	1,071.20
EIELSON AFB - DFAS	1/20/2016	11	7723	32.23	4.18	35.17	28.42	0.12	JD		4	973.20
EIELSON AFB - DFAS	1/21/2016	15	7638	32.53	4.44	34.87	28.17	0.13	JD		4	1,379.00
EIELSON AFB - DFAS	1/22/2016	12	7624	31.93	4.92	35.16	28.00	0.11	JD		4	1,105.20
EIELSON AFB - DFAS	1/26/2016	12	7490	32.32	5.40	34.27	28.01	0.11	JD		4	1,134.75
EIELSON AFB - DFAS	1/27/2016	13	7533	31.49	5.77	34.90	27.85	0.12	Bdl/JD	J	4/4	1,215.95
EIELSON AFB - DFAS	1/28/2016	15	7573	32.67	4.75	34.63	27.96	0.10	Bdl/JD	J	4/4	1,350.75
EIELSON AFB - DFAS	2/2/2016	12	7557	32.09	4.95	35.17	27.80	0.10	JD/Bdl	/J	4/3	1,112.15
EIELSON AFB - DFAS	2/3/2016	12	7717	31.10	5.07	34.90	28.93	0.14	Bdl/JD	J	3/4	1,124.55
EIELSON AFB - DFAS	2/4/2016	13	7624	30.85	5.97	34.68	28.51	0.17	Bdl/JD	J	4/4	1,191.10
EIELSON AFB - DFAS	2/5/2016	12	7616	31.11	5.83	35.41	27.65	0.13	JD/Bdl	/J	4/4	1,132.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12
EIELSON AFB - DFAS	80214.85	7611.00	31.53	5.47	34.99	28.02	0.12
FORT WAINWRIGHT ACCOUNTING	126389.60	7620.00	31.49	5.41	35.01	28.08	0.12
OTHER COAL SALES	70008.05	7699.00	29.94	6.15	35.52	28.38	0.13
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12
Total	423697.4	7651.59	31.15	5.49	35.19	28.17	0.12

This analysis is representative of the coal shipped.
The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.
Coleen Thompson **Date** 7-18-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/5/2016	15	7570	30.93	6.78	34.59	27.71	0.13	JD/JD		3/4	1,417.10
AURORA ENERGY LLC	7/6/2016	10	7661	30.50	6.07	35.20	28.23	0.11	JD/JD		3/4	999.55
AURORA ENERGY LLC	7/8/2016	15	7588	31.27	6.06	35.54	27.13	0.11	JD/JD		3/4	1,368.70
AURORA ENERGY LLC	7/11/2016	19	7496	32.08	6.04	34.43	27.45	0.11	JD/JD		3/4	1,782.30
AURORA ENERGY LLC	7/12/2016	14	7507	30.39	7.57	35.14	26.90	0.16	Bdl/JD	K	4/3	1,387.10
AURORA ENERGY LLC	7/14/2016	18	7561	29.88	7.43	35.07	27.62	0.16	Bdl/JD	K/	4/3	1,766.80
AURORA ENERGY LLC	7/18/2016	17	7711	29.16	7.11	35.83	27.90	0.17	JD/Bdl	/K	3/4	1,594.70
AURORA ENERGY LLC	7/19/2016	15	7689	29.26	6.72	35.46	28.56	0.17	Bdl/JD	K	4/3	1,378.10
AURORA ENERGY LLC	7/21/2016	18	7652	29.41	6.98	35.14	28.47	0.17	Bdl/JD	K	4/3	1,724.10
AURORA ENERGY LLC	7/25/2016	12	7689	29.04	7.41	34.83	28.73	0.17	Bdl/JD	K	4/3	1,116.65
AURORA ENERGY LLC	7/26/2016	11	7590	29.91	7.20	34.97	27.92	0.16	Bdl/JD	K	4/3	1,036.20
AURORA ENERGY LLC	7/28/2016	11	7616	29.35	7.50	35.18	27.97	0.18	Bdl/JD	K	4/3	1,042.70
AURORA ENERGY LLC	8/1/2016	14	7596	29.24	8.06	34.84	27.87	0.15	Bdl/JD	K	4/3	1,351.50
AURORA ENERGY LLC	8/2/2016	14	7456	30.31	8.00	34.62	27.08	0.15	Bdl/JD	K/	4/3	1,371.25
AURORA ENERGY LLC	8/4/2016	13	7543	30.45	7.11	34.97	27.47	0.14	Bdl/JD	K	4/3	1,234.55
AURORA ENERGY LLC	8/8/2016	19	7554	29.57	8.13	34.64	27.67	0.15	Bdl/JD	K	4/3	1,829.20
AURORA ENERGY LLC	8/9/2016	17	7555	29.32	8.20	34.99	27.50	0.16	Bdl/JD	K/	4/3	1,727.15
AURORA ENERGY LLC	8/12/2016	17	7518	28.78	8.93	35.37	26.93	0.22	JD/Bdl	/K	3/4	1,641.20
AURORA ENERGY LLC	8/15/2016	17	7662	28.43	8.18	35.09	28.30	0.21	Bdl/JD	K	4/3	1,541.00
AURORA ENERGY LLC	8/16/2016	17	7663	29.02	7.89	35.79	27.31	0.18	Bdl/JD	K	4/3	1,617.55
AURORA ENERGY LLC	8/18/2016	16	7544	29.54	7.80	35.74	26.92	0.17	Bdl/JD	K	4/3	1,515.30
AURORA ENERGY LLC	8/23/2016	19	7487	29.32	8.70	36.15	25.83	0.18	Bdl/JD	K	4/3	1,860.65
AURORA ENERGY LLC	8/24/2016	19	7632	29.26	7.19	36.57	26.99	0.16	Bdl/JD	K	4/3	1,808.85
AURORA ENERGY LLC	8/25/2016	18	7590	31.48	5.63	35.08	27.81	0.13	JD/JD		4/3	1,682.30
AURORA ENERGY LLC	8/29/2016	19	7289	30.74	9.14	34.44	25.70	0.22	JD/JD		4/3	1,838.20
AURORA ENERGY LLC	8/30/2016	18	7582	30.55	6.91	35.46	27.09	0.15	JD/JD		3/4	1,697.80
AURORA ENERGY LLC	9/2/2016	26	7500	30.40	7.65	35.22	26.74	0.14	JD/JD		3/4	2,510.75
AURORA ENERGY LLC	9/6/2016	18	7450	32.43	6.09	34.66	26.83	0.12	JD/JD		4/3	1,694.70
AURORA ENERGY LLC	9/7/2016	17	7524	31.76	5.90	35.65	26.70	0.12	JD/Bdl	/K	3/4	1,605.50
AURORA ENERGY LLC	9/8/2016	10	7550	30.91	6.94	34.82	27.35	0.13	JD/Bdl	/K	4/4	953.55

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	9/9/2016	10	7573	30.37	6.68	35.37	27.58	0.12	Bdl/JD	K	4/3	959.50
AURORA ENERGY LLC	9/27/2016	7	7558	29.53	7.77	36.09	26.62	0.14	JD/JD		3/4	660.95
AURORA ENERGY LLC	9/30/2016	18	7663	29.00	7.19	36.55	27.26	0.12	JD/Bdl	/K	3/4	1,783.60
AURORA ENERGY LLC	10/3/2016	24	7551	30.59	7.00	35.86	26.56	0.11	JD/Bdl	/K	3/4	2,244.55
AURORA ENERGY LLC	10/5/2016	28	7514	30.13	7.52	34.79	27.56	0.12	Bdl/JD	K	4/3	2,682.10
AURORA ENERGY LLC	10/10/2016	20	7615	29.98	6.97	35.09	27.97	0.12	Bdl/JD	K	4/3	1,895.45
AURORA ENERGY LLC	10/11/2016	21	7415	29.36	9.27	34.88	26.50	0.12	JD		4	1,974.25
AURORA ENERGY LLC	10/17/2016	14	7725	30.51	5.80	35.47	28.22	0.11	JD		4	1,327.05
AURORA ENERGY LLC	10/18/2016	10	7666	30.86	5.74	35.75	27.65	0.11	JD/JD		3/4	910.90
AURORA ENERGY LLC	10/19/2016	11	7674	30.61	5.79	35.44	28.17	0.10	JD/JD		3/4	940.90
AURORA ENERGY LLC	10/24/2016	12	7760	29.11	6.56	36.37	27.97	0.12	JD/JD		3/4	1,137.45
AURORA ENERGY LLC	10/25/2016	12	7729	29.22	6.51	36.28	27.99	0.12	Bdl		6	1,063.15
AURORA ENERGY LLC	10/26/2016	14	7708	28.38	7.47	36.44	27.71	0.12	Bdl/JD		6/4	1,171.40
AURORA ENERGY LLC	10/27/2016	14	7765	27.43	7.69	37.53	27.36	0.13	Bdl/JD		6/4	1,243.80
AURORA ENERGY LLC	10/31/2016	14	7742	26.38	8.92	37.76	26.94	0.14	Bdl		6	1,220.95
AURORA ENERGY LLC	11/1/2016	15	7705	26.55	9.09	38.27	26.09	0.14	Bdl		6	1,290.10
AURORA ENERGY LLC	11/2/2016	14	7726	26.53	8.80	37.76	26.91	0.14	Bdl		6	1,238.05
AURORA ENERGY LLC	11/3/2016	13	7774	26.33	8.55	37.90	27.23	0.14	Bdl		6	1,100.70
AURORA ENERGY LLC	11/7/2016	15	7680	27.17	8.92	37.45	26.47	0.13	Bdl		6	1,346.80
AURORA ENERGY LLC	11/8/2016	15	7646	26.81	9.38	37.93	25.89	0.14	Bdl		6	1,315.35
AURORA ENERGY LLC	11/9/2016	15	7631	27.00	9.17	37.46	26.37	0.14	Bdl		6	1,316.60
AURORA ENERGY LLC	11/10/2016	16	7714	26.75	8.56	37.61	27.09	0.13	Bdl		6	1,394.90
AURORA ENERGY LLC	11/14/2016	16	7658	26.44	9.11	37.77	26.68	0.14	Bdl		6	1,432.15
AURORA ENERGY LLC	11/16/2016	16	7680	27.17	8.40	37.84	26.60	0.14	Bdl		6	1,436.00
AURORA ENERGY LLC	11/17/2016	15	7748	27.26	7.86	37.64	27.24	0.13	Bdl		6	1,320.90
AURORA ENERGY LLC	11/21/2016	16	7710	27.01	8.43	37.84	26.73	0.13	Bdl		6	1,456.15
AURORA ENERGY LLC	11/22/2016	19	7751	27.30	8.01	38.35	26.34	0.13	Bdl		6	1,754.65
AURORA ENERGY LLC	11/23/2016	17	7736	27.32	7.92	38.15	26.61	0.13	Bdl		6	1,432.75
AURORA ENERGY LLC	11/28/2016	10	7705	27.45	7.89	37.39	27.28	0.13	Bdl		6	876.20
AURORA ENERGY LLC	11/29/2016	10	7464	27.88	9.89	36.20	26.04	0.13	Bdl		6	923.55
AURORA ENERGY LLC	11/30/2016	10	7586	29.83	6.92	36.51	26.75	0.13	JD		4	881.80
AURORA ENERGY LLC	12/1/2016	11	6899	28.06	14.52	32.87	24.55	0.12	Bdl/JD		6/4	913.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	12/5/2016	12	7660	30.15	6.54	35.11	28.21	0.15	JD	4	1,048.05
AURORA ENERGY LLC	12/6/2016	12	7635	29.90	6.82	35.74	27.54	0.14	JD	4	1,034.60
AURORA ENERGY LLC	12/7/2016	11	7691	30.39	5.66	35.64	28.32	0.12	Bdl/JD	6/4	934.95
AURORA ENERGY LLC	12/8/2016	12	7684	29.22	7.21	37.06	26.52	0.12	JD	4	1,028.90
AURORA ENERGY LLC	12/12/2016	15	7734	28.36	7.03	36.54	28.08	0.16	JD	4	1,336.05
AURORA ENERGY LLC	12/13/2016	15	7656	27.80	8.19	37.25	26.77	0.14	JD	4	1,297.80
AURORA ENERGY LLC	12/14/2016	15	7683	27.72	7.99	36.90	27.40	0.14	JD	4	1,347.60
AURORA ENERGY LLC	12/15/2016	8	7679	27.93	7.85	36.68	27.55	0.15	JD/Bdl	4/6	735.90
AURORA ENERGY LLC	12/19/2016	18	7626	27.91	8.63	37.07	26.40	0.14	Bdl/JD	6/4	1,625.50
AURORA ENERGY LLC	12/20/2016	23	7529	28.73	8.36	36.18	26.74	0.13	Bdl	6	2,003.15
AURORA ENERGY LLC	12/21/2016	8	7177	33.28	5.98	34.15	26.60	0.11	JD	4	702.25
AURORA ENERGY LLC	12/22/2016	7	7498	30.41	6.92	35.74	26.93	0.13	JD	4	625.90
AURORA ENERGY LLC	12/27/2016	13	7617	30.42	6.60	35.98	27.01	0.12	JD	4	1,202.80
AURORA ENERGY LLC	12/28/2016	13	7774	30.23	5.76	36.52	27.49	0.13	JD/Bdl	4/6	1,132.75
AURORA ENERGY LLC	12/29/2016	14	7656	30.08	6.37	36.50	27.06	0.13	Bdl/JD	6/4	1,242.95
AURORA ENERGY LLC	12/29/2016	4	7427	30.47	7.75	35.36	26.42	0.13	Bdl/JD	6/4	355.05
AURORA ENERGY LLC	12/31/2016	14	7668	27.72	8.27	37.22	26.79	0.14	Bdl/JD	6/4	1,292.45

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	107687.35	7604.00	29.23	7.61	35.99	27.17	0.14

This analysis is representative of the coal shipped.
The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.
Coleen Thompson **Date** 1-11-17

Coleen Thompson
Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/3/2017	18	7477	30.01	7.72	36.14	26.13	0.14	JD		4	1,692.15
AURORA ENERGY LLC	1/4/2017	19	7629	29.79	6.61	35.98	27.62	0.14	JD		4	1,625.15
AURORA ENERGY LLC	1/5/2017	19	7546	29.25	7.60	35.83	27.32	0.16	JD/STK		4/L	1,722.00
AURORA ENERGY LLC	1/6/2017	19	7556	32.13	5.19	35.58	27.11	0.12	JD		4	1,667.00
AURORA ENERGY LLC	1/10/2017	16	7711	31.53	4.83	35.98	27.66	0.11	JD		4	1,414.60
AURORA ENERGY LLC	1/11/2017	11	7587	32.46	4.80	35.38	27.37	0.12	JD		4	960.60
AURORA ENERGY LLC	1/12/2017	15	7557	32.36	5.01	35.04	27.60	0.12	JD		4	1,360.55
AURORA ENERGY LLC	1/13/2017	10	7657	31.58	5.05	35.99	27.38	0.15	JD		4	911.65
AURORA ENERGY LLC	1/16/2017	11	7484	33.02	5.28	34.59	27.11	0.13	JD		4	953.00
AURORA ENERGY LLC	1/17/2017	7	7796	31.16	4.49	35.71	28.65	0.11	JD		4	560.65
AURORA ENERGY LLC	1/19/2017	8	7453	32.25	5.64	35.11	27.00	0.13	JD		4	622.05
AURORA ENERGY LLC	1/20/2017	7	7517	33.70	4.45	34.77	27.08	0.11	JD		4	636.35
AURORA ENERGY LLC	1/21/2017	14	7599	33.03	4.28	34.94	27.75	0.10	JD		4	1,222.40
AURORA ENERGY LLC	1/23/2017	11	7669	32.37	4.38	35.00	28.26	0.10	JD		4	970.45
AURORA ENERGY LLC	1/24/2017	11	7726	32.24	4.34	35.68	27.75	0.10	JD		4	941.95
AURORA ENERGY LLC	1/25/2017	11	7644	32.08	4.71	35.28	27.94	0.09	JD		4	974.55
AURORA ENERGY LLC	1/26/2017	8	7572	32.05	5.46	34.92	27.57	0.10	JD		4	718.10
AURORA ENERGY LLC	1/27/2017	11	7639	31.03	5.90	36.14	26.94	0.12	JD		4	981.45
AURORA ENERGY LLC	1/30/2017	11	7572	32.29	5.53	35.74	26.45	0.12	JD		4	953.15
AURORA ENERGY LLC	1/31/2017	11	7217	32.88	6.93	34.88	25.31	0.14	JD		4	975.95
AURORA ENERGY LLC	2/1/2017	24	6822	34.48	8.09	32.84	24.60	0.14	JD		4	2,255.10
AURORA ENERGY LLC	2/1/2017	4	7170	33.55	6.67	33.62	26.17	0.13	JD		4	355.30
AURORA ENERGY LLC	2/1/2017	3	7252	33.71	5.99	33.75	26.56	0.13	JD		4	267.25
AURORA ENERGY LLC	2/6/2017	9	7551	32.85	4.86	34.74	27.55	0.12	JD		4	790.05
AURORA ENERGY LLC	2/7/2017	10	7554	33.29	4.68	34.92	27.12	0.11	JD		4	877.60
AURORA ENERGY LLC	2/8/2017	10	7691	32.19	4.46	35.15	28.22	0.11	JD		4	869.65
AURORA ENERGY LLC	2/9/2017	9	7651	32.24	4.61	35.16	28.01	0.12	JD		4	796.00
AURORA ENERGY LLC	2/10/2017	10	7729	31.63	4.62	35.76	28.00	0.11	JD		4	875.35
AURORA ENERGY LLC	2/13/2017	9	7625	32.37	4.69	35.17	27.77	0.13	JD		4	790.10
AURORA ENERGY LLC	2/14/2017	8	7567	32.56	4.97	35.16	27.32	0.11	JD		4	692.50

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	2/15/2017	10	7634	32.54	4.49	35.36	27.61	0.11	JD	4	869.00
AURORA ENERGY LLC	2/16/2017	8	7498	33.04	4.98	35.17	26.82	0.12	JD	4	717.70
AURORA ENERGY LLC	2/17/2017	9	7463	33.10	5.10	34.31	27.50	0.12	JD	4	814.60
AURORA ENERGY LLC	2/21/2017	8	7588	32.49	4.85	35.18	27.48	0.12	JD	4	701.75
AURORA ENERGY LLC	2/22/2017	11	7557	33.17	4.44	34.73	27.66	0.11	JD	4	980.00
AURORA ENERGY LLC	2/23/2017	12	7563	32.96	4.14	35.22	27.69	0.10	JD	4	1,045.50
AURORA ENERGY LLC	2/24/2017	12	7688	32.39	4.22	35.42	27.98	0.11	JD	4	957.20
AURORA ENERGY LLC	2/27/2017	14	7690	32.22	4.51	35.99	27.28	0.11	JD	4	1,176.20
AURORA ENERGY LLC	3/1/2017	13	7165	33.78	5.52	34.38	26.32	0.11	JD	4	1,197.25
AURORA ENERGY LLC	3/2/2017	12	7074	33.61	5.95	34.70	25.75	0.11	JD	4	1,089.10
AURORA ENERGY LLC	3/3/2017	17	7451	31.82	5.88	35.09	27.21	0.11	JD	4	1,454.95
AURORA ENERGY LLC	3/6/2017	26	7216	32.35	6.16	35.29	26.19	0.11	JD	4	2,389.10
AURORA ENERGY LLC	3/8/2017	13	7505	31.11	6.36	35.34	27.20	0.12	JD/Bdl	4/6	1,072.30
AURORA ENERGY LLC	3/11/2017	28	7281	33.37	5.39	35.01	26.24	0.12	JD/Bdl	4/6	2,582.40
AURORA ENERGY LLC	3/11/2017	12	7569	32.00	4.79	36.18	27.04	0.10	JD/Bdl	4/6	1,076.05
AURORA ENERGY LLC	3/14/2017	13	7651	31.55	4.89	35.87	27.69	0.11	JD	4	1,119.25
AURORA ENERGY LLC	3/15/2017	15	7583	31.90	5.01	35.77	27.32	0.12	JD	4	1,321.40
AURORA ENERGY LLC	3/20/2017	13	7524	32.29	4.83	35.84	27.04	0.12	JD	4	1,120.40
AURORA ENERGY LLC	3/21/2017	12	7579	32.14	4.66	35.78	27.42	0.12	JD	4	1,035.50
AURORA ENERGY LLC	3/22/2017	12	7667	32.19	4.11	35.51	28.20	0.11	JD	4	1,045.35
AURORA ENERGY LLC	3/23/2017	14	7595	31.37	5.88	34.77	27.97	0.13	JD/GRP	4/C	1,240.20
AURORA ENERGY LLC	3/27/2017	14	7651	31.46	5.35	35.39	27.81	0.13	JD/GRP	4/C	1,246.80
AURORA ENERGY LLC	3/28/2017	14	7626	31.21	5.57	34.76	28.47	0.13	JD/GRP	4/M	1,254.00
AURORA ENERGY LLC	3/29/2017	10	7571	31.75	5.59	34.86	27.81	0.13	JD/GRP	4/M	902.05
AURORA ENERGY LLC	3/30/2017	13	7577	31.50	5.45	35.40	27.65	0.12	JD/GRP	4/M	1,119.90
AURORA ENERGY LLC	4/3/2017	13	7646	31.95	4.45	36.24	27.36	0.11	JD	4	1,123.15
AURORA ENERGY LLC	4/4/2017	13	7653	32.13	4.28	36.07	27.52	0.10	JD	4	1,148.05
AURORA ENERGY LLC	4/5/2017	13	7681	31.32	5.21	35.50	27.97	0.13	JD/GRP	4/C	1,164.90
AURORA ENERGY LLC	4/6/2017	8	7615	32.59	4.35	35.95	27.12	0.10	JD	4	726.65
AURORA ENERGY LLC	4/10/2017	11	7682	32.21	4.28	37.03	26.49	0.11	JD	4	977.45
AURORA ENERGY LLC	4/11/2017	12	7681	31.95	4.39	35.97	27.69	0.10	JD	4	1,085.65
AURORA ENERGY LLC	4/12/2017	7	7552	33.01	4.28	35.11	27.60	0.11	JD	4	674.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	4/13/2017	11	7385	34.02	4.57	34.56	26.86	0.10	JD	4	1,018.95
AURORA ENERGY LLC	4/18/2017	15	7644	32.05	4.35	36.70	26.91	0.11	JD	4	1,391.00
AURORA ENERGY LLC	4/19/2017	7	7663	31.22	5.39	35.74	27.64	0.13	JD	4	624.95
AURORA ENERGY LLC	4/20/2017	15	7624	32.50	4.35	35.84	27.31	0.11	JD	4	1,314.50
AURORA ENERGY LLC	4/21/2017	17	7590	31.89	4.70	35.91	27.50	0.11	JD	4	1,591.90
AURORA ENERGY LLC	4/24/2017	15	7675	31.63	4.45	36.49	27.44	0.10	JD	4	1,391.90
AURORA ENERGY LLC	4/25/2017	13	7577	33.14	4.06	35.38	27.44	0.11	JD	4	1,272.55
AURORA ENERGY LLC	4/26/2017	9	7592	33.84	3.51	35.03	27.62	0.10	JD	4	894.20
AURORA ENERGY LLC	4/27/2017	8	7621	32.87	3.81	36.16	27.16	0.10	JD	4	775.45
AURORA ENERGY LLC	5/1/2017	7	7734	31.63	4.44	36.23	27.71	0.12	JD	4	645.70
AURORA ENERGY LLC	5/2/2017	6	7739	30.89	4.60	36.41	28.10	0.11	JD	4	563.10
AURORA ENERGY LLC	5/3/2017	4	7825	30.98	4.22	36.19	28.62	0.11	JD	4	371.55
AURORA ENERGY LLC	5/8/2017	4	7461	33.26	4.78	35.09	26.88	0.12	JD	4	381.75
AURORA ENERGY LLC	5/9/2017	6	7489	32.64	5.06	34.89	27.42	0.11	JD	4	517.50
AURORA ENERGY LLC	5/11/2017	4	7538	31.86	5.27	35.86	27.02	0.11	JD	4	359.75
AURORA ENERGY LLC	5/15/2017	9	7599	31.85	4.95	36.29	26.91	0.10	JD	4	807.40
AURORA ENERGY LLC	5/16/2017	8	7633	31.97	4.66	36.40	26.98	0.10	JD	4	739.40
AURORA ENERGY LLC	5/17/2017	5	7574	33.83	4.08	34.88	27.20	0.09	JD	4	466.55
AURORA ENERGY LLC	5/18/2017	4	7650	33.31	3.42	35.81	27.47	0.09	JD	4	354.65
AURORA ENERGY LLC	5/19/2017	7	7656	32.09	4.24	35.89	27.79	0.10	JD	4	603.30
AURORA ENERGY LLC	5/22/2017	16	7756	31.40	4.24	36.49	27.87	0.10	JD	4	1,430.45
AURORA ENERGY LLC	5/23/2017	12	7512	33.57	4.17	35.75	26.51	0.13	JD	4	1,090.40
AURORA ENERGY LLC	5/24/2017	12	7669	32.70	3.95	35.99	27.36	0.12	JD	4	1,097.30
AURORA ENERGY LLC	5/26/2017	14	7657	31.91	4.59	36.48	27.02	0.11	JD	4	1,311.30
AURORA ENERGY LLC	5/30/2017	9	7675	31.80	4.72	36.29	27.19	0.11	JD	4	835.35
AURORA ENERGY LLC	5/31/2017	8	7693	31.83	4.71	36.93	26.53	0.11	JD	4	747.65
AURORA ENERGY LLC	6/1/2017	3	7701	31.47	4.41	37.05	27.07	0.10	JD	4	265.40
AURORA ENERGY LLC	6/2/2017	4	7777	31.10	4.13	36.64	28.13	0.10	JD	4	346.30
AURORA ENERGY LLC	6/5/2017	12	7650	32.12	4.55	35.36	27.98	0.10	JD	4	1,061.75
AURORA ENERGY LLC	6/6/2017	13	7594	32.33	4.47	35.40	27.81	0.11	JD	4	1,165.40
AURORA ENERGY LLC	6/8/2017	12	7636	32.08	4.40	35.99	27.53	0.10	JD	4	1,067.80
AURORA ENERGY LLC	6/9/2017	11	7674	31.80	4.30	36.21	27.70	0.11	JD	4	1,011.25

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	6/12/2017	12	7609	32.30	4.32	36.00	27.38	0.10	JD	4	1,063.85
AURORA ENERGY LLC	6/13/2017	13	7682	31.87	4.25	36.35	27.54	0.09	JD	4	1,140.90
AURORA ENERGY LLC	6/15/2017	12	7675	31.97	4.75	36.23	27.06	0.12	JD	4	1,093.80
AURORA ENERGY LLC	6/16/2017	13	7665	32.28	4.53	35.98	27.21	0.12	JD	4	1,167.30
AURORA ENERGY LLC	6/19/2017	11	7699	32.34	3.91	36.45	27.31	0.10	JD	4	982.95
AURORA ENERGY LLC	6/20/2017	12	7714	32.35	4.07	35.98	27.60	0.10	JD	4	1,115.05
AURORA ENERGY LLC	6/22/2017	12	7555	33.32	4.39	35.52	26.77	0.12	JD	4	1,083.45
AURORA ENERGY LLC	6/23/2017	13	7642	32.79	4.37	35.68	27.17	0.12	JD	4	1,163.90
AURORA ENERGY LLC	6/26/2017	8	7699	32.23	4.30	35.95	27.52	0.12	JD	4	701.50
AURORA ENERGY LLC	6/27/2017	8	7754	31.81	4.08	36.33	27.78	0.11	JD	4	701.85
AURORA ENERGY LLC	6/28/2017	8	7711	31.90	4.58	36.91	26.61	0.11	JD	4	752.00
AURORA ENERGY LLC	6/29/2017	8	7760	31.78	4.09	36.29	27.85	0.10	JD	4	696.20

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	106040.35	7567.00	32.20	4.98	35.56	27.26	0.11

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-5-17

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/3/2017	12	7517	32.85	4.69	35.25	27.22	0.11	JD		4	1,086.15
AURORA ENERGY LLC	7/5/2017	13	7551	33.12	4.11	35.68	27.09	0.11	JD		4	1,188.30
AURORA ENERGY LLC	7/6/2017	13	7595	33.11	4.06	35.63	27.20	0.11	JD		4	1,252.50
AURORA ENERGY LLC	7/7/2017	12	7494	33.16	4.13	35.09	27.62	0.11	JD		4	1,164.50
AURORA ENERGY LLC	7/10/2017	11	7516	34.02	4.15	34.55	27.28	0.10	JD		4	1,011.85
AURORA ENERGY LLC	7/11/2017	12	7258	33.79	5.22	35.08	25.92	0.10	JD		4	1,161.40
AURORA ENERGY LLC	7/13/2017	12	6947	34.61	6.24	34.51	24.64	0.10	JD		4	1,145.45
AURORA ENERGY LLC	7/14/2017	11	6816	34.98	6.18	34.21	24.63	0.11	JD		4	1,072.45
AURORA ENERGY LLC	7/17/2017	12	7074	34.52	5.03	34.87	25.58	0.10	JD		4	1,122.60
AURORA ENERGY LLC	7/18/2017	13	7306	33.58	4.88	35.16	26.38	0.11	JD		4	1,222.85
AURORA ENERGY LLC	7/20/2017	13	7165	33.99	5.19	35.42	25.40	0.10	JD		4	1,243.85
AURORA ENERGY LLC	7/25/2017	9	7331	33.62	4.81	35.34	26.24	0.11	JD		4	853.00
AURORA ENERGY LLC	7/26/2017	8	7372	33.16	4.93	35.34	26.58	0.11	JD		4	766.70
AURORA ENERGY LLC	7/27/2017	9	7444	33.20	4.78	35.50	26.53	0.11	JD		4	862.10
AURORA ENERGY LLC	7/28/2017	8	7326	33.62	5.09	35.23	26.07	0.11	JD		4	772.70
AURORA ENERGY LLC	7/31/2017	12	7067	34.65	5.05	34.54	25.77	0.11	JD		4	1,152.10
AURORA ENERGY LLC	8/1/2017	12	7141	33.99	4.94	34.81	26.27	0.11	JD		4	1,150.10
AURORA ENERGY LLC	8/3/2017	12	7164	33.98	5.14	34.57	26.31	0.11	JD		4	1,147.95
AURORA ENERGY LLC	8/4/2017	12	7286	33.90	4.79	35.05	26.27	0.11	JD		4	1,145.30
AURORA ENERGY LLC	8/7/2017	9	7378	33.17	5.03	34.99	26.81	0.11	JD		4	782.15
AURORA ENERGY LLC	8/10/2017	19	7253	33.46	5.18	35.37	25.99	0.11	JD		4	1,810.35
AURORA ENERGY LLC	8/11/2017	20	7318	33.17	5.03	35.36	26.46	0.12	JD		4	1,908.20
AURORA ENERGY LLC	8/14/2017	11	7460	33.07	4.73	35.90	26.91	0.11	JD		4	1,010.35
AURORA ENERGY LLC	8/15/2017	12	7178	34.62	5.07	34.00	26.32	0.12	JD		4	1,140.70
AURORA ENERGY LLC	8/17/2017	12	7233	35.07	4.27	34.48	26.19	0.11	JD		4	1,118.45
AURORA ENERGY LLC	8/18/2017	11	7230	34.34	4.20	35.09	26.38	0.10	JD		4	1,012.25
AURORA ENERGY LLC	8/21/2017	12	7183	34.66	4.57	34.70	26.08	0.10	JD		4	1,132.10
AURORA ENERGY LLC	8/22/2017	11	6965	35.25	5.44	33.99	25.32	0.11	JD		4	1,063.00
AURORA ENERGY LLC	8/24/2017	13	7340	33.83	4.89	35.51	25.78	0.11	JD		4	1,237.30
AURORA ENERGY LLC	8/25/2017	12	7298	33.44	4.79	35.35	26.43	0.10	JD		4	1,143.30

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	8/29/2017	13	7624	32.09	3.98	36.19	27.75	0.09	JD	4	1,160.75
AURORA ENERGY LLC	8/30/2017	12	7693	31.67	4.26	35.95	28.12	0.11	JD	4	1,089.50
AURORA ENERGY LLC	8/31/2017	13	7679	31.66	4.54	36.00	27.81	0.12	JD	4	1,198.20
AURORA ENERGY LLC	9/1/2017	16	7556	31.91	4.68	35.57	27.85	0.10	JD	4	1,489.65
AURORA ENERGY LLC	9/5/2017	15	7539	32.49	4.50	35.78	27.23	0.10	JD	4	1,313.40
AURORA ENERGY LLC	9/6/2017	14	7605	32.58	4.13	35.67	27.62	0.10	JD	4	1,306.00
AURORA ENERGY LLC	9/7/2017	14	7651	32.11	4.32	35.95	27.62	0.09	JD	4	1,299.30
AURORA ENERGY LLC	9/8/2017	10	7585	31.81	4.55	35.94	27.71	0.10	JD	4	909.40
AURORA ENERGY LLC	9/11/2017	13	7579	32.39	4.29	35.79	27.54	0.10	JD	4	1,150.80
AURORA ENERGY LLC	9/12/2017	14	7570	32.66	4.03	35.18	28.14	0.09	JD	4	1,235.95
AURORA ENERGY LLC	9/14/2017	14	7678	31.81	4.31	35.96	27.92	0.10	JD	4	1,318.55
AURORA ENERGY LLC	9/18/2017	9	7664	31.53	4.49	35.95	28.03	0.11	JD	4	813.25
AURORA ENERGY LLC	9/19/2017	10	7672	31.57	4.48	35.65	28.30	0.10	JD	4	900.45
AURORA ENERGY LLC	9/21/2017	10	7631	31.22	4.92	36.67	27.20	0.10	JD	4	922.80
AURORA ENERGY LLC	9/22/2017	9	7661	31.07	5.17	36.47	27.30	0.12	JD	4	832.35
AURORA ENERGY LLC	9/25/2017	14	7589	32.54	4.30	35.50	27.67	0.09	JD	4	1,297.15
AURORA ENERGY LLC	9/26/2017	14	7566	32.73	4.36	35.38	27.54	0.10	JD	4	1,304.80
AURORA ENERGY LLC	9/28/2017	12	7661	32.02	4.42	36.00	27.57	0.11	JD	4	1,105.45
AURORA ENERGY LLC	9/29/2017	8	7647	31.64	4.46	35.89	28.01	0.10	JD	4	747.05
AURORA ENERGY LLC	10/2/2017	9	7605	32.57	4.32	35.30	27.82	0.10	JD	4	844.05
AURORA ENERGY LLC	10/5/2017	9	7616	32.89	4.09	35.23	27.80	0.10	JD	4	818.45
AURORA ENERGY LLC	10/6/2017	8	7615	32.44	4.76	35.48	27.33	0.11	JD	4	735.40
AURORA ENERGY LLC	10/9/2017	17	7741	31.67	4.13	36.41	27.80	0.11	JD	4	1,505.25
AURORA ENERGY LLC	10/12/2017	18	7559	32.46	4.67	35.40	27.48	0.11	JD	4	1,721.25
AURORA ENERGY LLC	10/13/2017	17	7502	33.04	4.45	35.28	27.23	0.11	JD	4	1,610.35
AURORA ENERGY LLC	10/16/2017	16	7505	32.67	4.78	35.05	27.50	0.09	JD	4	1,462.45
AURORA ENERGY LLC	10/19/2017	16	7635	32.62	4.06	35.25	28.08	0.09	JD	4	1,483.05
AURORA ENERGY LLC	10/20/2017	16	7771	30.64	4.79	36.18	28.40	0.11	JD	4	1,506.45
AURORA ENERGY LLC	10/23/2017	11	7512	32.84	4.78	34.95	27.43	0.11	JD	4	1,055.65
AURORA ENERGY LLC	10/24/2017	10	7659	32.80	3.76	35.58	27.85	0.10	JD	4	960.95
AURORA ENERGY LLC	10/26/2017	10	7778	31.71	3.93	36.18	28.18	0.11	JD	4	935.50
AURORA ENERGY LLC	10/27/2017	12	7626	[illegible]	4.57	35.54	28.56	0.11	JD	4	1,090.80

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	10/30/2017	17	7638	31.96	4.43	35.98	27.64	0.10	JD	4	1,583.00
AURORA ENERGY LLC	10/31/2017	15	7737	32.08	3.80	35.41	28.72	0.09	JD	4	1,398.05
AURORA ENERGY LLC	11/2/2017	15	7695	31.20	4.63	36.13	28.04	0.10	JD	4	1,375.15
AURORA ENERGY LLC	11/3/2017	16	7568	31.90	5.28	35.76	27.07	0.10	JD	4	1,498.40
AURORA ENERGY LLC	11/6/2017	17	7608	31.44	5.45	34.85	28.27	0.10	JD	4	1,507.55
AURORA ENERGY LLC	11/7/2017	25	7199	33.84	6.32	33.54	26.31	0.09	JD	4	2,432.20
AURORA ENERGY LLC	11/9/2017	7	7639	32.53	4.28	35.73	27.47	0.08	JD	4	600.95
AURORA ENERGY LLC	11/10/2017	17	7717	30.82	4.79	36.38	28.02	0.09	JD	4	1,518.10
AURORA ENERGY LLC	11/13/2017	6	7373	33.38	5.42	34.41	26.79	0.11	JD	4	560.55
AURORA ENERGY LLC	11/14/2017	7	7599	32.39	4.85	35.41	27.35	0.13	JD	4	677.50
AURORA ENERGY LLC	11/16/2017	9	7624	31.94	4.82	35.41	27.84	0.11	JD	4	820.35
AURORA ENERGY LLC	11/20/2017	11	7626	32.25	4.95	35.18	27.62	0.11	JD	4	995.15
AURORA ENERGY LLC	11/21/2017	12	7635	31.90	4.96	35.51	27.63	0.10	JD	4	1,060.50
AURORA ENERGY LLC	11/22/2017	11	7629	31.87	4.81	35.55	27.77	0.10	JD	4	943.05
AURORA ENERGY LLC	11/24/2017	9	7651	31.86	5.02	35.92	27.20	0.12	JD	4	822.90
AURORA ENERGY LLC	11/27/2017	14	7651	31.89	4.89	35.59	27.65	0.12	JD	4	1,257.20
AURORA ENERGY LLC	11/28/2017	20	7615	31.98	4.99	35.71	27.32	0.12	JD	4	1,793.75
AURORA ENERGY LLC	11/30/2017	21	7709	30.84	5.07	35.82	28.27	0.11	JD	4	1,894.15
AURORA ENERGY LLC	12/1/2017	21	7729	30.82	4.85	35.86	28.47	0.12	JD	4	1,908.30
AURORA ENERGY LLC	12/4/2017	17	7826	30.71	4.58	35.95	28.76	0.11	JD	4	1,546.15
AURORA ENERGY LLC	12/5/2017	17	7744	31.15	4.70	35.94	28.21	0.11	JD	4	1,532.85
AURORA ENERGY LLC	12/7/2017	16	7705	31.63	4.59	36.11	27.68	0.11	JD	4	1,428.20
AURORA ENERGY LLC	12/8/2017	15	7601	32.26	4.91	35.14	27.70	0.11	JD	4	1,388.25
AURORA ENERGY LLC	12/11/2017	15	7797	31.63	3.60	35.87	28.90	0.09	JD	4	1,388.65
AURORA ENERGY LLC	12/12/2017	15	7660	30.94	5.44	36.04	27.59	0.10	JD	4	1,419.85
AURORA ENERGY LLC	12/14/2017	16	7730	30.96	5.02	35.96	28.06	0.10	JD	4	1,446.45
AURORA ENERGY LLC	12/18/2017	13	7651	32.79	3.74	34.77	28.71	0.09	JD	4	1,162.00
AURORA ENERGY LLC	12/19/2017	14	7671	32.52	3.99	35.38	28.13	0.09	JD	4	1,281.55
AURORA ENERGY LLC	12/21/2017	14	7678	32.56	4.03	35.53	27.89	0.08	JD	4	1,276.25
AURORA ENERGY LLC	12/22/2017	13	7713	32.05	3.93	35.61	28.41	0.09	JD	4	1,194.20
AURORA ENERGY LLC	12/26/2017	10	7713	32.68	3.47	35.50	28.34	0.08	JD	4	900.45
AURORA ENERGY LLC	12/27/2017	11	7708	32.11	4.22	[illegible]	28.38	0.10	JD	4	972.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	12/28/2017	11	7766	31.21	4.38	35.91	28.51	0.09	JD	4	975.75
AURORA ENERGY LLC	12/29/2017	10	7711	31.41	4.64	35.99	27.96	0.10	JD	4	876.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	114440.00	7529.00	32.52	4.68	35.45	27.36	0.10

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Ben Ziegman **Date:** 1/4/18

Ben Ziegman

Signature

Appendix D (Professional Memos)

ENVIRONMENT
& HEALTH

MEMO

To **David Fish, Aurora Energy LLC**
From **Till Stoeckenius**
Subject **Summary of issues related to SO_2 precursor demonstration for Fairbanks**

Date November 15, 2018

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The Alaska Department of Environmental Conservation (ADEC) is currently developing a State Implementation Plan (SIP) for the Fairbanks North Star Borough serious $PM_{2.5}$ nonattainment area (NAA). Fairbanks was reclassified from a moderate $PM_{2.5}$ NAA to a serious $PM_{2.5}$ NAA in June 2017; the serious area SIP is due by December 2018.

As provided for in 40 CFR 51.1006, states can reduce the regulatory burden of complying with $PM_{2.5}$ NAA requirements in the Clean Air Act by conducting $PM_{2.5}$ precursor demonstrations showing that one or more precursors involved in formation of secondary $PM_{2.5}$ do not significantly contribute to violations of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). The current ADEC draft serious area SIP preparation plan includes precursor demonstrations for ammonia (NH_3), nitrogen oxides (NO_x), and volatile organic compounds (VOCs) which conclude that each of these three precursors do not significantly contribute to nonattainment. ADEC did not perform a precursor demonstration for sulfur dioxide (SO_2).

A draft Best Available Control Technology (BACT) demonstration completed by the ADEC as required by the CAA for serious NAAs identifies dry sorbent injection as BACT for the four major SO_2 sources in the Fairbanks NAA. In recognition of the possibility that the SIP may include a requirement for SO_2 controls on their sources without a clear indication of the potential benefits of such controls for reducing ambient $PM_{2.5}$ concentrations, owners of the four major SO_2 sources in the Fairbanks NAA requested (via Aurora Energy) Ramboll's assistance with evaluating possible approaches to conducting a successful major source SO_2 precursor demonstration for Fairbanks.

In accordance with our letter agreement with Aurora of 18 September, Ramboll performed research and analysis related to an SO_2 precursor demonstration for the Fairbanks 24-hour $PM_{2.5}$ serious nonattainment area (NAA). Ramboll reviewed documents describing data analysis and modeling conducted by ADEC and its contractors for the 2014 Fairbanks moderate area SIP and draft analyses and plans for developing the serious NAA SIP. This included detailed descriptions of emission inventory development, meteorological and photochemical dispersion modeling methods and related sensitivity analyses, air monitoring data analyses and receptor modeling studies and other related materials. Representatives from Ramboll, Aurora Energy and owners of the other major SO_2 sources located within the Fairbanks NAA, along with ADEC and EPA Region X, participated in a conference call to discuss issues involved in conducting a successful major source SO_2 precursor demonstration. We also had several one-on-one conversations with David Fish of Aurora and Robert Ellerman of EPA Region X. A common theme in these discussions was a significant level of skepticism by ADEC and EPA regarding the likelihood of success in developing an approvable major source SO_2 precursor demonstration for the Fairbanks Serious area SIP given uncertainties about sulfate formation mechanisms under Fairbanks winter conditions. A summary of our findings is provided below.

A key element of a NAA SIP is a demonstration that planned emission reductions will result in attainment of the NAAQS in future years. ADEQ uses a computer model (CMAQ) to carry out this attainment demonstration. CMAQ is a photochemical dispersion model which simulates the transport, dispersion, and chemical transformation of emissions from all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors (NH_3, NO_x, VOC, SO_2) affecting the NAA. In order to complete its work within the available time and resources, ADEC is planning to use the same base year $PM_{2.5}$ episodes (Episode 1: 23 January – 11 February 2008 and Episode 2: 2 – 17 November 2008) and modeling approach for the serious NAA SIP attainment demonstration as were used in the moderate area SIP attainment demonstration. This is despite the limited amount of air quality monitoring data available during these episodes and the fact that air quality conditions in Fairbanks have changed significantly since 2008 due to emission reductions during the intervening years. Monitoring of $PM_{2.5}$ component species was conducted at the State Office Building (SOB) in downtown Fairbanks during the 2008 episodes. These data were used in the moderate area SIP to evaluate the ability of CMAQ to accurately reproduce the observed concentrations of $PM_{2.5}$ and its component species.

As shown in Table 1, comparisons of CMAQ predicted $PM_{2.5}$ with observed $PM_{2.5}$ showed over prediction of organic carbon (OC) and elemental carbon (EC) and under predictions of other PM species, including sulfate (SO_4). These over and underpredictions fortuitously balanced each other out, resulting in an apparently accurate prediction of $PM_{2.5}$ total mass. The prediction errors for individual PM species may be the result of an inaccurate emissions inventory or errors in CMAQ (or in the WRF model used to provide meteorological inputs to CMAQ). Of particular note is that CMAQ predicted very little in situ formation of sulfate from SO_2 emissions due to the lack of available oxidizing agents in the model. In technical documents prepared for the Fairbanks moderate area $PM_{2.5}$ SIP, ADEC concluded that CMAQ is under predicting the amount of secondary sulfate formation under the unique Fairbanks winter conditions due to some unknown SO_2 oxidation pathway.

Table 1. Comparison of observed and predicted PM species concentrations at State Office Building monitoring site (average over days with FRM measurements in both 2008 episodes).

Species	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)	Bias (%)
$PM_{2.5}$ (total)	36.1	35.7	-1%
OC	17.0	24.5	44%
EC	2.3	4.3	87%
SO_4	6.2	2.1	-66%
NO_3	1.6	1.3	-19%
NH_4	3.1	1.2	-61%
OTH	6.3	2.3	-63%

Source: *Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan.* D. Huff, Alaska Department of Environmental Conservation, 25 September 2014, in Reasonably Available Control Measure (RACM) Analysis (Appendix III.D.5.7 to the Fairbanks $PM_{2.5}$ Moderate State Implementation Plan).

In accordance with EPA's precursor demonstration guidelines, a successful precursor demonstration (in this case for SO_2) must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ NAAQS. More specifically, for a major source SO_2 precursor demonstration, the guidance requires a demonstration that eliminating SO_2 emission from all major sources within the NAA would not lower $PM_{2.5}$ concentrations by more than an insignificant amount (defined in the guidance as an amount not exceeding 1.5 $\mu g/m^3$).[1] If this "contribution-based" analysis indicates that the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 $\mu g/m^3$, then a "sensitivity-based" analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 – 70% would have only an insignificant impact on lowering $PM_{2.5}$ (also defined as an impact of less than 1.5 $\mu g/m^3$).
The primary obstacle to conducting a credible SO_2 precursor demonstration for Fairbanks cited by ADEC and EPA results from a combination of two facts:

1. the relatively large contribution of sulfate to total $PM_{2.5}$ mass (approximately 17-18% at the SOB) which results in an ammonium sulfate contribution to $PM_{2.5}$ design value[2] that is well in excess of the "insignificant" concentration threshold (1.5 $\mu g/m^3$) cited in EPA's precursor demonstration guidance document and which thus implicates the combined impact of major and minor SO_2 sources as significant contributors to peak $PM_{2.5}$ levels; and
2. the large under prediction of sulfate mass by CMAQ for the 2008 episodes (normalized mean bias of -66%)[3] which leads to the conclusion that the current modeling system (consisting of CMAQ and the emissions estimates and meteorological modeling results used as inputs to CMAQ) does not accurately characterize the contributions of SO_2 sources to the $PM_{2.5}$ design value.

In other words, SO_2 sources are observed to contribute significantly to $PM_{2.5}$ nonattainment and the current modeling system is not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2 sources. This makes it difficult to develop a precursor attainment

[1] While the 2016 guidance document recommends using 1.3 μg/m3, EPA recently updated and finalized the technical basis document used to set the recommended level and revised the significance threshold to 1.5 μg/m3.

[2] The design value is the pollutant concentration that is compared to the level of the NAAQS. For the 24-hour $PM_{2.5}$ NAAQS, the design value is the annual 98th percentile daily average concentration averaged over three years.

[3] "Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan", D. Huff 9/25/14, Table 1 (p. 125) in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7.

demonstration for major sources of SO_2 based on the current data and modeling system that otherwise would be considered sufficiently reliable to gain approval by EPA. We note that this also brings into question the reliability of a modeled attainment demonstration that includes SO_2 controls on major sources.

Despite the difficulties noted above with formulating an approvable major source SO_2 precursor demonstration, data analyses and modeling conducted for the Fairbanks moderate area SIP[4] provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment. We summarize these key results below:

- Analysis of CMAQ model results by UAF show almost no secondary SO_4 production during the modeled periods. Thus, nearly all of the modeled SO_4 is from primary SO_4 emissions.
- CMAQ underpredicted the SO_4 concentration at the SOB by an average of 3.22 $\mu g/m^3$ on days with FRM measurements during the 2008 winter episodes (the average observed SO_4 was 5.25 $\mu g/m^3$ while the average predicted SO_4 was 2.03 $\mu g/m^3$; note that these values are taken from Table 2 of *Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7* and differ slightly from the values in Table 1; we are still trying to determine the reason for these small differences).[5]
- ADEC concluded that there is likely sufficient excess NH_4 present under episode conditions so that reductions of secondary SO_4 would not lead to significant increases in other secondary species such as ammonium nitrate.[6]
- Both CMAQ point source SO_2 "zero out" runs - in which results from the base case CMAQ run are compared with a CMAQ run in which point source SO_2 emissions are reduced to zero - and CALPUFF model runs show that point sources contribute approximately 22% of the total modeled SO_2 from all sources at the SOB monitor with nearly all of the remaining SO_2 coming from heating oil combustion. [7] Note that the modeled point sources consist of the six major SO_2 sources in the nonattainment area.
- CMAQ zero out runs also show that 5% of primary SO_4 is from point sources. The CMAQ SO_4 prediction at SOB is 2.1 $\mu g/m^3$ (Table 1) so the modeled point source primary SO_4 contribution is no more than $0.05 * 2.1 = 0.1$ $\mu g/m^3$.
- Comparisons of total $PM_{2.5}$ mass concentration to the NAAQS are made using data from a Federal Reference Method (FRM) monitor. However, $PM_{2.5}$ species composition data are obtained from a SASS sampler. $PM_{2.5}$ measurements from these two different monitoring methods are not directly comparable due to various unavoidable sampling artifacts. In accordance with EPA guideline procedures, ADEC applied adjustments to the $PM_{2.5}$ species composition data from the SASS sampler at the SOB using the SANDWICH algorithm to more accurately reflect the composition of $PM_{2.5}$ samples collected by the FRM monitor. These adjustments account for differences in the amount of nitrate, ammonium, carbon, other primary $PM_{2.5}$ components (OPP), and particle bound water (PBW) captured by the two instruments.
- For purposes of developing the moderate area SIP, ADEC used the available ambient monitoring data processed through the SANDWICH algorithm to develop a "design day" $PM_{2.5}$ composition representative of the average composition of $PM_{2.5}$ during high wintertime $PM_{2.5}$ episodes. ADEC also calculated the applicable $PM_{2.5}$ "design value" which represents the $PM_{2.5}$ total mass concentration that is compared to the level of the NAAQS. For the moderate area SIP, the $PM_{2.5}$ design value at the

[4] https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-moderate-sip

[5] See Table 2, p. 129 in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7

[6] Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7, p. 131.

[7] Note that the CALPUFF point source modeling showed that on average only 0.1% of modeled point source SO_2 at SOB during the during Jan. 23rd – Feb 9th 2008 episode days was from the Flint Hills refinery, whereas 36% was from the four power plants and 64% from Ft. Wainwright.

SOB site was determined to be 44.7 μg/m³. Applying the design day composition to the design value results in the design day $PM_{2.5}$ component concentrations shown in Figure 1.

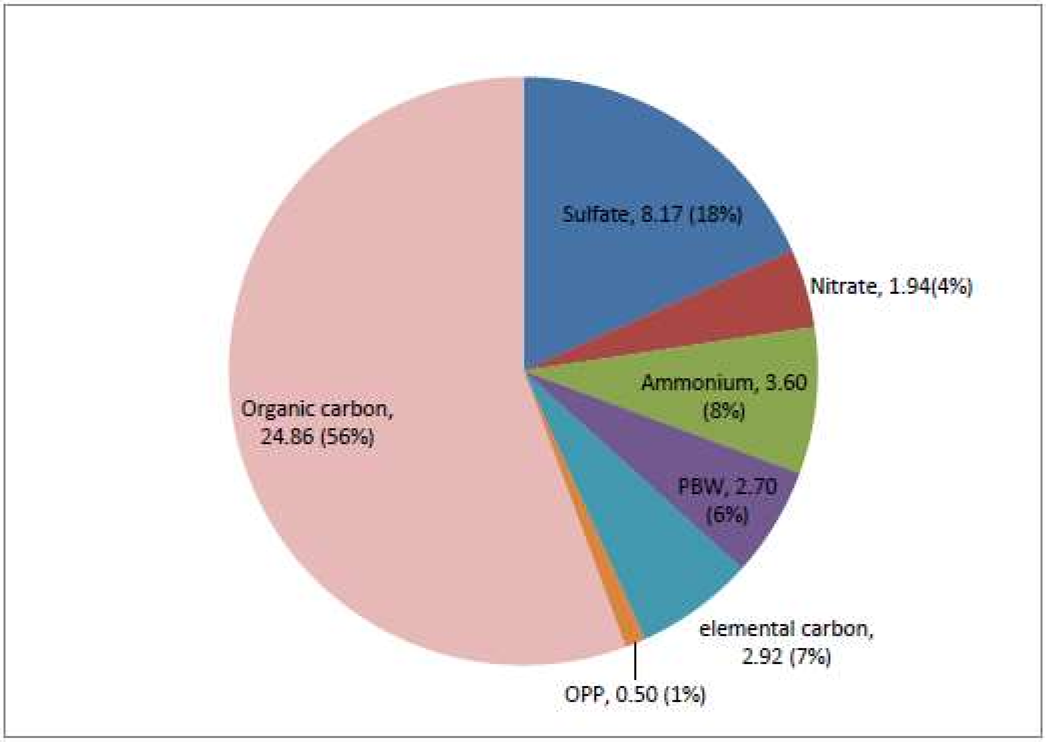

Figure 1. Design day $PM_{2.5}$ speciation at SOB used for the moderate area SIP (source: Appendix III.5.7, p. 122).

- For the design day, the 0.1 μg/m³ primary sulfate contribution from point sources estimated from the CMAQ zero-out runs noted above scales up to 0.16 μg/m³ (= 0.1 * 8.17/5.25) where 8.17 μg/m³ is the amount of SO_4 on the design day and 5.25 μg/m³ is the average observed amount of SO_4 for the modeled episodes.
- The design day PM composition shown in Figure 1 includes 8.17 μg/m³ SO_4. The correspondingly scaled SO_4 that is unaccounted for in the CMAQ results is 3.22 * (8.17/5.25) = 5.01 μg/m³. At one extreme, all of this "unexplained" SO_4 could be attributed to emissions from point sources (i.e., the major SO_2 sources). Perhaps more realistically, one could estimate that 22% of the unexplained SO_4 (0.22 * 5.01 = 1.1 μg/m³) is from point sources, in keeping with the modeled 22% contribution of point sources to SO_2 noted above. Assuming all SO_4 is in the form of ammonium sulfate, this would be equivalent to a 1.1 * (132/96) = 1.51 μg/m³ contribution to $PM_{2.5}$, where the factor 132/96 represents the molecular weight ratio of ammonium sulfate to sulfate. Adding to this the amount of particle bound water (PBW) associated with ammonium sulfate assumed in the SANDWICH estimate of FRM measurement (2/3 * 2.70 μg/m³ = 1.80 μg/m³ assumed to be associated with 8.17 μg/m³ of SO_4 so 1.1 μg/m³ * (1.80/8.17) = 0.24 μg/m³ of PBW associated with the point source SO_4) results in a total point source ammonium sulfate with associated PBW contribution of 1.51 + 0.24 = 1.75 μg/m³.
- The above simple "contribution-based" precursor demonstration result indicates that the major source SO_2 contribution is slightly above the "insignificant contribution" threshold (1.5 μg/m³) cited

in EPA's Precursor Demonstration Guidance. However, the EPA guidance allows for a "sensitivity-based" precursor demonstration in which the reduction in $PM_{2.5}$ concentration resulting from a 30, 50, or 70% reduction in SO_2 emissions is compared to the 1.5 μg/m^3 significance threshold. Based on a linear extrapolation from the above analysis, a maximum 70% reduction in major source SO_2 emissions would be expected to produce a 1.23 μg/m^3 decrease in $PM_{2.5}$, which is below the 1.5 μg/m^3 significance threshold. In other words, the $PM_{2.5}$ design value is relatively insensitive to even a large (70%) reduction in major source SO_2 emissions.

Although the above result for a sensitivity-based SO_2 precursor demonstration is encouraging, it must be noted that the precursor demonstration guideline suggests that ADEC may still need to include consideration of the feasibility of major source SO_2 reduction measures in its SIP, even if the sensitivity-based demonstration produces a result below the significance threshold. This may be particularly important for Fairbanks given uncertainties about the amount of SO_4 actually contributed by the major sources.

It is also important to keep in mind that conditions have changed in Fairbanks since 2008 and the new Serious area SIP will use a base year of 2013 to represent "current conditions". Updated area source emissions will be modeled but episodic point source emissions will be based on the 2008 point source inventory. Modeling results are not yet available, so it is not possible to know how the above results might differ for the new base year.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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November 16, 2017

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

ADEC and EPA reviewed the BACT analysis provided for the Aurora Chena Power Plant and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry

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[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

injection or spray dry system. It further states that the installation of such technologies would be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering dry sorbent injection (DSI). However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, Captured Emissions (tons per year), Emissions Reduction (tons per year), Capital Costs (2017 dollars), Operating Costs (dollars per year), Annualized Costs (dollars per year), and Cost Effectiveness (dollars per ton) using EPA's cost manual. Please see Comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.
8. Good Combustion Practices –For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

Aurora Energy – Chena Power Plant
BACT Analysis Review Comments
Report dated March 2017 – Environmental Resources Management

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

1. Equipment Life – Some of the calculations[1] submitted with the analysis use a 10 year equipment life at ten percent interest rate. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. The analysis must also provide written basis for the interest rate assumed if it differs from the standard seven percent rate used in the EPA Air Pollution Control Cost Manual.
2. SO_2 Control Technologies – The BACT analyses must include substantive analysis of the following four SO_2 control technologies, at a minimum: wet scrubbing (such as limestone slurry forced oxidation), spray-dry scrubbing, dry flue gas desulfurization (dry scrubbing), and dry sorbent injection. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question.
4. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided.
5. EPA Cost Spreadsheets – The EPA has recently updated the cost manual chapters pertaining to SCR and SNCR, and developed cost spreadsheets to be used for evaluation of this technology for cost effectiveness[2]. The cost analyses for these technologies must be consistent with the updated cost manual chapter and cost spreadsheet.
6. Space Constraints – In order to establish a control technology as not technically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
7. Retrofit Costs – EPA Region 10 believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.
8. Potential vs. Actual Emissions – All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The

[1] See for example, NOx cost calcs-MARCH 2017 FINAL.xlsx
[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

9. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided.

THE STATE of ALASKA

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Department of Environmental Conservation

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April 24, 2015

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Voluntary BACT Analysis for Chena Power Plant

Dear Mr. Fish:

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

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

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

<u>Background</u>
EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

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

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

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

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

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

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

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

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

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

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

Sincerely,

Denise Koch, Director
Division of Air Quality

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

AURORA ENERGY

December 22, 2017

Denise Koch
Director, Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, AK 99811-1800

Subject: Response to November 16, 2017 request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by December 22, 2017

Dear Ms. Koch:

Aurora is responding to the request for additional information to supplement the Best Available Control Technology (BACT) Technical Memorandum provided to the Alaska Department of Environmental Conservation (ADEC) on March 20, 2017. In response, a detailed BACT analysis for sulfur controls is included as an addendum to the original BACT analysis. We are confident that our initial submittal and enclosed response are sufficient to make a preliminary BACT determination consistent with our selected BACT. Aurora is convinced expending additional and substantial resources to provide further analysis is not warranted considering that ADEC has established, through moderate area planning efforts, that our facility's contribution to ground level particulate matter during air quality events is minimal.

Aurora realizes that a BACT analysis must be conducted for applicable stationary sources regardless of the level of contribution to the problem or impact on the area's ability to achieve attainment. However, the request for additional information hints at the Departments next steps of requiring heat and power producers, such as Aurora, to install technology which will have minimal impact on bringing the area into attainment.

Collectively, the large stationary sources contribute less than 10% of the total $PM_{2.5}$ concentration as illustrated by ADEC.[1] According to the moderate area planning efforts, Aurora makes up less than 1% of the contribution from large stationary sources.[2] The cost to mitigate Aurora's less than one percent contribution to ground-level particulate matter would require tens of millions of dollars in capital investments and annualized operating costs which would be passed on to the consumer in increased power and district heat rates. Current electric rates in the Interior are already some of the highest in the country. Market competition dictates that district heating costs are priced to be competitive with oil and natural gas. An increase in district heat

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[1] Clear the Air Conference. 2017. http://co.fairbanks.ak.us/transportation/Pages/AQConference2017.aspx, Source Apportionment Presentation, Slide 21, accessed 11/29/2017.

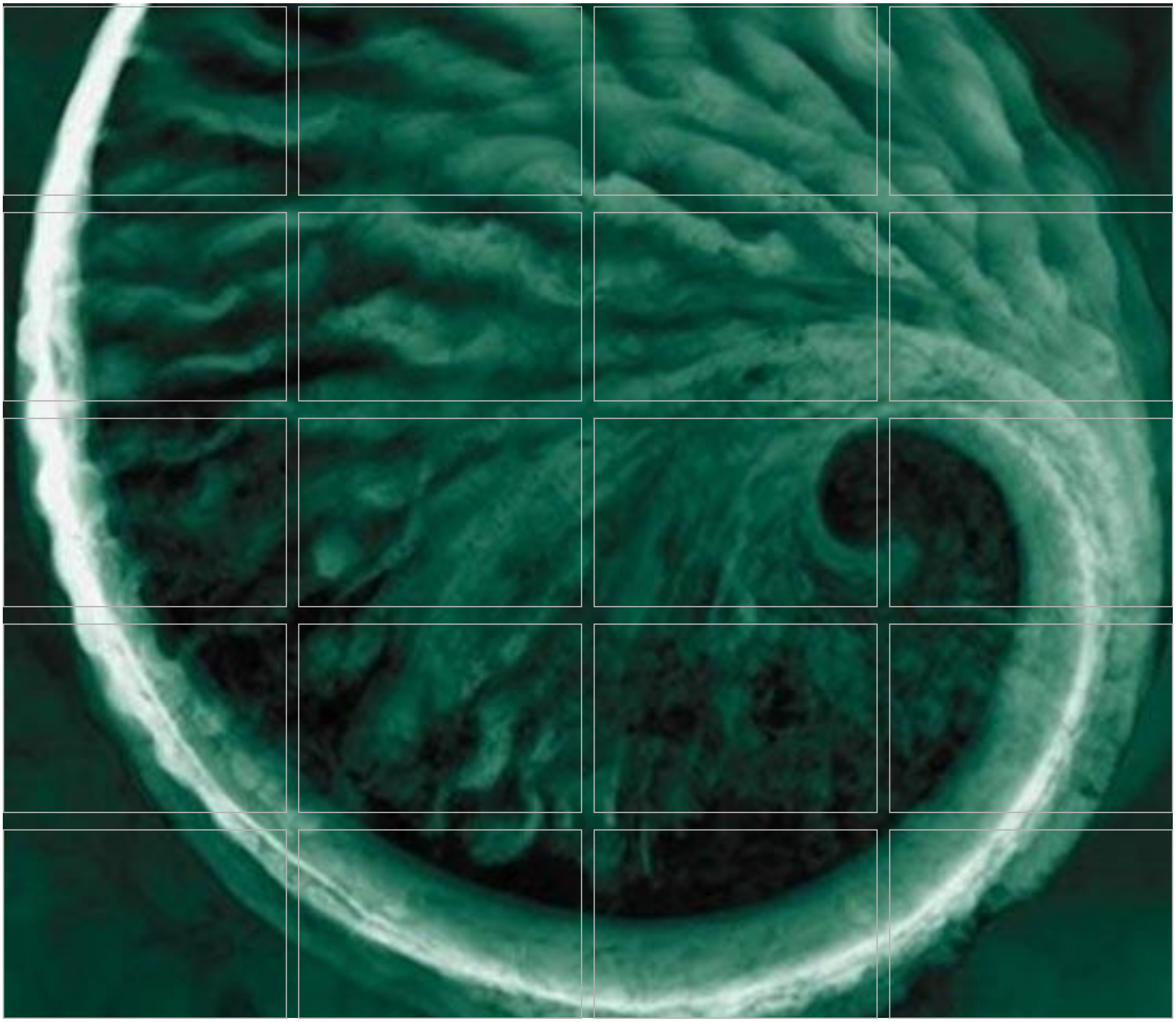
[2] State Implementation Plan, ADEC. 2014. http://dec.alaska.gov/air/anpms/comm/docs/fbxSIPpm2-5/III.D.5-PM2.5_SIP_Sections-Adopted_09.07.16.pdf, pg 167 of 233. Accessed 11/29/2017.

rates could encourage consumers to switch to ground-level heating sources, such as oil and wood, which would exacerbate the area's air quality problems and impede local progress toward attainment.

In short, BACT is prohibitively costly, impractical, and ineffective in this situation. The implementation of additional control technology on Aurora would, at best, provide minimal benefit to air quality and would likely result in unintended consequences. Aurora believes that ADEC, EPA and Aurora could work together to identify a mechanism in the planning process that recognizes the air quality benefit of Aurora's district heating system which displaces the equivalent of over two million gallons of wintertime ground-level heating oil emissions. As such, district heating is a proven solution to Fairbanks' air quality issues. Aurora hopes that ADEC will take these points into consideration in anticipation of the Department's preliminary BACT determination for public review.

Sincerely,

Buki Wright
President



Addendum to Best Available Control Technology Analysis

Chena Power Plant
Fairbanks, Alaska

December 2017

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Prepared for:
Aurora Energy, LLC

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Addendum to Best Available Control Technology Analysis

Chena Power Plant
Fairbanks, Alaska

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December 2017

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ACRONYMS AND ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
BACT	best available control technology
CAA	Clean Air Act
CMB	chemical mass balance
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FNSB	Fairbanks North Star Borough
ft	foot or feet
GVEA	Golden Valley Electric Association
LAER	Lowest Achievable Emission Rate
lb/hr	pound per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NOx	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	Normalized stoichiometric ratio
OH	hydroxyl
PM	particulate matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
RACT	reasonable available control technology
SIP	State Implementation Plan
SO_2	sulfur dioxide
ton/yr	tons per year
U.S.	United States
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic

1 INTRODUCTION

As described in the original Best Available Control Technology (BACT) Analysis report, Aurora Energy, LLC (Aurora) operates four coal-fired boilers, three similarly-sized smaller units and one larger unit, at the facility known as the Chena Power Plant (Chena).[1] The combined exhaust from the four boilers at Chena is currently directed to a single fabric filter for control of particulate matter (PM). Figure 1 presents an aerial view of the Chena facility where the four coal-fired boilers are located. The duct work from the three smaller boilers can be seen coming out of two different buildings along 1st Avenue. The duct work from the larger boiler is not clearly visible, but comes out of a third building and connects to the other combined ducts just prior to entering the south side of the fabric filter housing. The fabric filter housing, visible as a blue structure in the figure, is one of the larger individual structures that occupies the site. The PM collected in the fabric filter is conveyed to the adjacent ash silo for storage until trucked off site.

The four Chena boilers combust low sulfur coal to achieve a sulfur dioxide (SO_2) emission rate equivalent to 0.39 pounds of SO_2 per million Btu of heat input (lb SO_2/MMBtu). The coal is "local" coal mined at the Usibelli Coal Mine in Healy, Alaska.

The techniques available for controlling SO_2 emissions from a coal-fired boiler include the following:

- Use of flue gas desulfurization (FGD) technology
  - Wet scrubber
  - Dry scrubber (lime injection and spray dryer/absorber)
  - Limestone or other dry sorbent injection

Most wet FGD systems employ two stages: one for fly ash removal and the other for SO_2 removal. In wet scrubbing systems, the flue gas first passes through a fly ash removal device, either an electrostatic

[1] Environmental Resources Management, Inc., Best Available Control Technology Analysis, Chena Power Plant, Fairbanks, AK, revised March 2017.

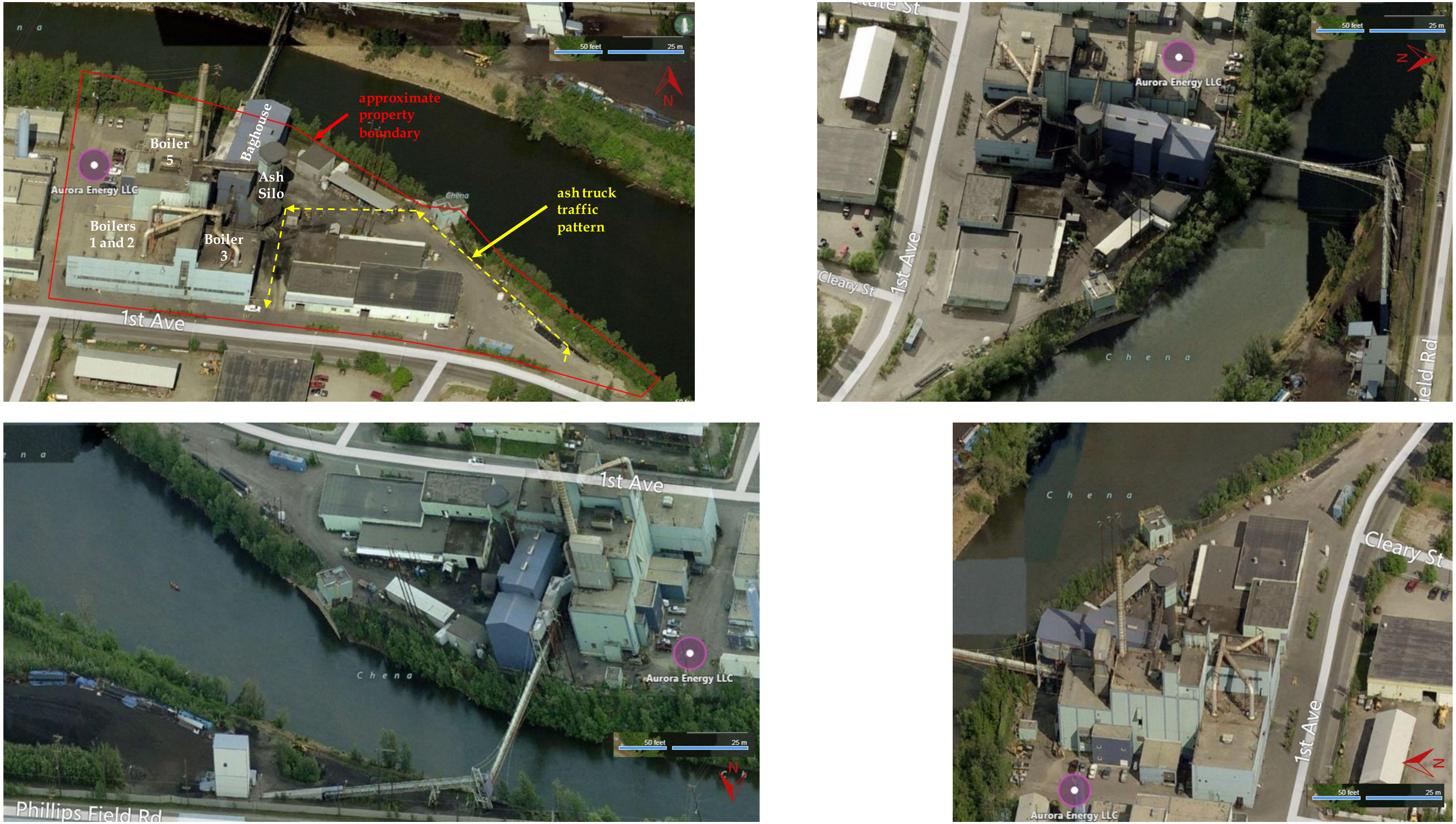

Figure 1. Aerial View of Chena Power Plant.

precipitator (ESP) or a fabric filter, and then into the SO_2 absorber. Due to cost constraints, wet FGD systems are not commonly used to reduce SO_2 emissions from boilers combusting low-sulfur coal. The original Chena Power Plant BACT Analysis presented a detailed discussion of the technical feasibility and cost of using a wet scrubber at Chena. Wet scrubbing technology was discounted as BACT in the original analysis due to the high cost-effectiveness (although many other technical challenges, such as space constraints, exist when considering wet scrubber technology at Chena). Additional discussion of FGD using a wet scrubber is therefore not needed at this time.

1.1 ADDITIONAL SO_2 CONTROLS SELECTED FOR EVALUATION

This BACT Addendum concentrates on evaluation of dry FGD technology, which consists of the spray dryer/absorber (SDA) option and the dry sorbent injection (DSI) option. In SDA or DSI operations, the SO_2 is first reacted with the sorbent, and then the flue gas passes through a PM control device.

The ability of a SDA or DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the calcium or sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form hydrochloric acid (HCl) in the flue gas and consume a portion of the injected lime. In an SDA system, actual sorbent consumption is influenced by the discharge temperature selected for the system, as this controls the amount of water sprayed into the flue gas. .

The ability to employ an add-on SO_2 control system also is influenced by site-specific factors, including space limitations. Use of a SDA or DSI system in concert with the somewhat peculiar equipment orientation at Chena, i.e., four boilers controlled by a single fabric filter, would require major alterations of the existing ductwork and possibly the fabric filter. The boiler houses and ducts would need to be retrofit with various equipment items to accommodate the sorbent delivery systems and PM handling systems required by a SDA or DSI system.

The following paragraphs present an overview of these two selected dry FGD technologies in general and a description of some of the site-specific issues associated with their use at Chena.

1.2 *SPRAY DRYER/ABSORBER*

A U.S. EPA Air Pollution Control Technology Fact Sheet for FGD technologies states that scrubbers are capable of reduction efficiencies in the range of 50 to 98%.[2] The highest removal efficiencies are achieved by wet scrubbers, and the lowest by dry scrubbers (typically less than 80%). Low SO_2 loadings to a dry absorber, as are obtained when using low sulfur coal, tend to produce lower removal efficiencies, between 40% and 70%. For comparison, the Consent Decree between the Golden Valley Electric Association, Inc. (GVEA) and the US EPA (dated November 19, 2012) and the subsequent Minor Permit issued by the Alaska Department of Environmental Conservation (ADEC) specified a 30-day SO_2 emission rate of no greater than 0.10 lb/MMBtu for Healy Power Plant (Healy) Unit 2 in Healy, AK while using SDA.[3] The Healy facility combusts similar coal as the Chena Power Plant, which produces an average uncontrolled emission rate of 0.39 lb SO_2/MMBtu. Achieving an emission rate of 0.10 lb SO_2/MMBtu thus represents a 74% reduction of average uncontrolled SO_2 emissions, which generally falls within the published range of performance for a SDA system.

In SDA systems, a slurry of sorbent material and water is fed to a spray dryer tower. In the tower, the slurry is atomized and injected into the gas, where droplets react with SO_2 as the liquid evaporates. This action produces a dry product that is collected in the bottom of the spray dryer and in the downstream PM removal equipment (i.e., fabric filter or electrostatic precipitator, ESP). The majority of the reaction takes place in the spray dryer. When a fabric filter is used, as the PM collects on the filter cloth, a filter cake would develop and allow the gas a second chance to react with the reagent, thus increasing utilization of the reagent and control efficiency. The fabric filter or ESP, downstream of the spray dryer, removes the PM, ash, reaction products (e.g., $CaSO_3$, $CaSO_4$, Na_2SO_4), and unreacted sorbent. The waste product can be disposed, sold as a by-product (depending on its quality), or recycled to the slurry. Various calcium and sodium-based reagents can be utilized as sorbent. SDA systems typically inject lime because it is more reactive than limestone and less expensive than sodium-based reagents. SO_2 control efficiencies

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[2] US EPA, Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf, accessed December 18, 2017.
[3] Technical Analysis Report – Permit AQ0173MSS01, April 14, 2014, Golden Valley Electric Association-Healy Power Plant.

are somewhat comparable for wet limestone scrubbers and spray dry systems, however, the capital and operating cost for spray dryer systems are lower than for wet systems, because equipment for handling liquid reagent and wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber because the flue gas is less humid.

It is reasonable to expect that SDA technology performance depends on the facility-specific process characteristics. The properties most important for a SDA application are an inlet gas temperature that allows the slurry to be evaporated in the flue gas (a necessity for a spray dry scrubber), adequate mixing and residence time that allow the sorbent to react with the SO_2 in the gas, and the use of a PM control device to separate the reaction products from the gas stream.

1.2.1 Site-specific Considerations for Using SDA at Chena

Flue Gas Take-off Point--The Chena plant employs a fabric filter to remove the PM from the combined flue gases of the four boilers operating at the site. A very short duct run, only about 10 feet, exists between the location where the flue gases are combined and the combined gas enters the fabric filter housing. At this point, the flue gas from Boiler 5 combines with the previously-combined flue gas from Boilers 1, 2, and 3. Three general SDA equipment orientations are possible for taking off flue gas for treatment in a spray dryer tower at Chena. The first orientation would take the flue gas from the point where all boiler flue gases have been combined prior to entering the fabric filter, i.e., in the 10-foot (ft) duct run. A second orientation would take the flue gas from Boiler 5 only (at some point prior to the 10-ft duct run) and provide control only of the SO_2 emitted by the larger boiler. A third orientation would take the combined flue gas as it exits the fabric filter. In any of these orientations, construction of duct work needed to deliver flue gas to the spray dryer tower would be complicated. Major changes to the gas flue flow regime would occur for any take-off point prior to the fabric filter. Major structural modifications of the fabric filter housing would be needed to accommodate a take-off point downstream of the fabric filter.

Spray Dryer Tower Location-- The Chena site is extremely congested, and very little vacant space is available for new construction. Therefore, spatial considerations are necessary when locating a spray dryer tower. A similarly sized boiler facility exists at the Golden Valley Electric Association (GVEA) plant in Healy, Alaska. The Healy Unit #2 boiler (683 MMBtu/hr) employs a SDA system, which is a similarly sized boiler burning run-of-mine coal from Usibelli. The spray dryer tower at the GVEA plant is 34 ft 9 in in diameter and stands 36 ft 9 in from the ground with a 29 ft 4 in, 60° Cone Hopper. Because of the congested area at Chena, a spray dryer tower would have to be located on the northern boundary of the property south of the river on the east or west of the outfall house. That location would situate the tower approximately 150 to 250 ft away from the combined flue gas junction just prior to the fabric filter inlet. After exiting the spray dryer tower, the treated gas would be redirected back to the 10-ft duct run at the fabric filter inlet for removal of PM. The baghouse design for the flue gas temperature at the inlet is 350 °F. Typically, the combined flue gases are between 300 and 315 °F at the inlet of the baghouse. The outlet temperature varies between 285 and 300 °F. The optimal temperature for SO_2 removal in a SDA is 10 to 15 °C below the saturation temperature to maximize the removal of SO_2. At approximately 15% moisture of Chena's flue gas, the saturation temperature would be around 88 °C (190 °F). This would cause wet solids to deposit on the absorber and downstream equipment. For spray dry systems, the temperature of the flue gas exiting the absorber must be 10 to 15 °C (20 to 50 °F) above the adiabatic saturation temperature.[4] The Healy plant inlet temperature is 300 °F and exists at 175 °F; however the O&M manual for the SDA references 185 °F as the outlet set point. Regardless, the long return duct run from the tower to the fabric filter would require reheating.to prevent moisture from condensing out of the gas. The reheating requirements will add to the increase in energy consumption from the control technology.

In a second option, Boiler 5 flue gas would be treated independently with a SDA system. For this option, the flue gas take-off point could be closer to the boiler, but the tower itself will still need to be located at a spot with available space approximately 100 to 200 ft away, and gas reheat would still be required as described for option 1. A separate spray tower for the combined flue gases from Boilers 1, 2, and 3 would have to be situated in the same area on the north side of the property as described above with ducting between 150 and 250 ft. This configuration is essentially the same as described in option 1 and therefore is not considered independently as an option.

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[4] Ibid (Air Pollution Control Technology Fact Sheet).

A third option would place the spray dryer tower after the fabric filter. This orientation would require a second fabric filter housing to be constructed at the facility. Based on an air-to-cloth ratio of 10 ft/min for lime[5], 0.39 lb/MMBtu SO_2 in the flue gas, a stoichiometric conversion from SO_2 to $CaSO_3$ (1.875), and a 75% removal efficiency, the filter area required of the secondary baghouse would be 25,000 ft^2. The current baghouse has a filter area of 61,000 ft^2 and a footprint of 35,035 ft^2 (not including the ducting and ID fans). Assuming the profile would be similar for the secondary baghouse, a footprint of 14,360 ft^2 would be required. Space is not available on Aurora's property for the installation of a second baghouse which would be about 40% the size of the current baghouse.

Existing PM Collection and Storage Equipment-- A SDA placed upstream of the existing Chena fabric filter would have several negative operational impacts. First, the amount of additional PM generated and sent to the existing fabric filter could cause the existing filter system to clean more continuously. The baghouse cleans when the differential pressure drop between inlet and outlet reaches 6 inches water column. The baghouse currently cycles through cleaning about 24 times a day. Assuming 4% fly ash is generated at an average operating load of 220,000 ton/yr of coal (2,000 lb/hour fly ash), the increase in fly ash at the projected maximum coal input rate of 283,824 ton/yr (2,592 lb/hour fly ash) would cause the baghouse to cycle 31 times a day (24 cycles/day x 2,592 lb/hr ÷ 2000 lb/hr). The additional particulate generation could increase the ash load to the baghouse by 267 lb/hr (0.39 lb SO_2/MMBtu at 75% removal efficiency). The additional load would increase the baghouse daily cleaning cycle to 34. The additional cycling of the system would require an increase in electrical consumption and operational maintenance.

While the particle loading could be accommodated by the existing baghouse, it is unlikely that additional airflow from added control technologies could be accommodated through the baghouse at maximum load. A stoichiometric analysis of the combustion flue gas, with 7% oxygen yields 11.1 lb of exhaust/lb of coal. The density of the exhaust air

[5] EPA. 2002. Air Pollution Cost Control Manual: Section 6, Particulate Matter Controls. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf. Research Triangle Park, North Carolina.

from the plant, based on average test data, is 0.048 lb/ft^3.[6] If a maximum projected heat input rate of 486 MMBtu/hr (283,824 ton/yr coal) were realized, the air flow through the baghouse would be 250,000 ft^3/min, which is the rated capacity of the baghouse. The stoichiometric analysis does not consider air infiltration which would increase the air flow to the baghouse beyond its capacity. Additional airflow needed for add-on control technologies would exceed the design air flow of the existing baghouse.

The duct reconstruction at the flue gas take-off point as well as the point where the treated flue gas is re-introduced to the fabric filter inlet also will require additional gas-handling equipment. Therefore, the additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance necessary to address potential plugging and filter replacement.

A take-off point after the existing fabric filter would alleviate the excessive PM loading issue. This orientation would require that a new outlet gas duct be retrofit onto the existing fabric filter housing to deliver the outlet gas to a second fabric filter. The existing filter vents through a roof monitor (also referred to as a monovent). In order to direct the fabric filter outlet gas to a downstream SDA system, one would need to open the top of the existing filter housing, weld new gas distribution plates to the outlet plenum, and construct a single gas outlet duct. This outlet duct would then be directed to the downstream SDA system, new fabric filter, and PM silo. The structural stability of the existing filter housing may be inadequate for handling the additional stress of the gas distribution components, in which case, extensive structural reinforcement would be needed. Construction of these items would demand more space than is available. As is clearly apparent by looking at Figure 1, the site has no extra space in which to build any such equipment for PM collection and storage. Additionally, operation of such a system orientation would increase the electric consumption at the facility. The average total electrical power consumption for the SDA system at the Healy Clean Coal

[6] Airflow Sciences Corporation. Chena PJFF Inlet Ductwork Flow Modeling. Fairbanks, Alaska. October 2015.

Project for their Healy Unit #2 during a performance test was 550.5 kW.[7] The Chena Power Plant baghouse power consumption is 460 kW. An SDA would potentially double the pollution control load of the plant and decrease the net sales of power approximately 2.4%.

***Contamination of Collected Particulate*--**The ash constituent loading would change as a result of adding sorbents used in the process. This change could render the ash unsuitable for beneficial use as a fill material. Fly ash collected at Chena is beneficially used as a construction fill material. The addition of sorbents could compromise the leaching characteristics of the ash which is a metric to determine its suitability for beneficial structural fill. Without adequate testing, there is uncertainty as to the impact of the sorbents on the leaching characteristics of the ash. Use of an SDA system downstream of the exiting fabric filter could alleviate this issue if the sorbent byproducts were addressed separately from combustion ash.

Facility Space Limitations for Ancillary Equipment-- Regardless of whether a SDA is placed upstream or downstream of the existing fabric filter, the spatial requirement of the system and auxiliary equipment will be difficult to accommodate. A SDA system would employ lime, Trona, or sodium bicarbonate as the scrubbing reagent. Extensive preliminary engineering would need to be performed to define space requirements for the scrubber tower(s); raw reagent receiving areas, piping, conveyors, and storage tanks and silos, and reagent mills; as well as similar equipment for handling the solid waste material generated in the system. The GVEA Healy plant, in addition to the SDA vessel, houses conveyors, recycle surge bin (12-ft diameter), slurry feed tank (7.5-ft diameter), slurry mixing tank (10.5-ft diameter), mill classifier, and a storage silo for the sorbent.

Much of the equipment needed for an SDA system would be large items that occupy a substantial footprint. As can be seen in Figure 1, very little unused space exists at the facility. No space exists for an enclosed spray tower, and therefore a tower would need to be sited outdoors. No space exists between the combined boiler ducts and the fabric filter (as seen in Figure 1) to insert a spray tower. Because all of these duct runs are located

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[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.

outdoors, maintaining the flue gas temperatures needed for the reaction and preventing moisture in the fabric filter will be expensive and difficult. Finally, as can be visualized by looking at Figure 1, the site does not have enough unused area to accommodate a dry material receiving operation and slurry preparation area. There is a likelihood that material receiving would have to occur on the north side of the Chena River. This would necessitate another river crossing which adds another layer of complexity to the process. Ultimately, the spatial considerations for the equipment would require a building to house the technology and heat to maintain the temperatures needed for the application. The parasitic load from electrical consumption and heating for the application would be substantial; at the least greater than 2.5% of current net generation.

1.3 DRY SORBENT INJECTION

In the utility industry, SO_2 may be removed by injecting a dry sorbent (limestone, Trona, or sodium bicarbonate are the common sorbents) into the combustion gases, typically above the burners or in the backpass before or after the air heater. Furnace DSI involves injection of the sorbent into the boiler system at a location downstream of the combustion zone through special injection ports. In DSI, the sorbent contacts the hot gas, decomposes, and reacts in suspension with SO_2 to form reaction products, such as calcium sulfate ($CaSO_4$), when using lime or limestone, or sodium sulfate (Na_2SO_4) when using Trona (sodium sesquicarbonate) or sodium bicarbonate. The reaction products, unreacted sorbent, and fly ash are removed at the PM control device (either an ESP or fabric filter) downstream from the boiler.

DSI has historically been used for reducing concentrations of hydrochloric acid (HCl), mercury, and sulfates (SO_3) from coal-fired boiler flue gas. Recently, DSI has seen greater use primarily as a system to comply with the Maximum Achievable Control Technology (MACT) requirements for boilers, aka, Boiler MACT. As operators began using DSI for HCl control in response to Boiler MACT, incidental removal of SO_2 was also being observed. SO_2 removal efficiencies of 30% to 70% have been reported for DSI in the utility industry when sorbent is injected and mixed at optimum conditions, and higher removals have been demonstrated in test/pilot operations. However these performance levels have yet to be widely demonstrated on a long-term continuous basis at permanent installations. For comparison, the Consent Decree between GVEA and the US EPA and the subsequent Minor Permit issued by the ADEC specified a 30-day SO_2 emission rate of no greater than 0.30 lb/MMBtu commencing

September 30, 2015 or 18 months after Healy Unit 2 first fired coal.[8] This emission rate represents a 23% reduction of average uncontrolled SO_2 emissions through the use of a DSI system.

In practice, the reaction chemistry of a DSI system is very straight forward. As a result, some level of SO_2 removal should be obtained when conditions exist that allow the reaction to take place. The performance of a DSI system for SO_2 removal is a function of several factors:

- Sorbent type
- Flue gas temperature at the injection location
- Sorbent particle size
- Sorbent injection rate, or Normalized Stoichiometric Ratio (NSR)
    - Extent of sorbent-to-gas mixing
    - Reaction residence time prior to the PM collection device
- PM control device type
- Flue gas properties
    - Concentrations of other acid gases competing with SO_2 reaction chemistry
    - Flow distribution and moisture content

Discussion of some of the more important aspects of DSI system performance is provided in the following paragraphs.

1.3.1 *Sorbent Type*

It is generally accepted that sodium-based sorbents (Trona and sodium bicarbonate) produce higher SO_2 removal rates than calcium-based sorbents (lime or limestone). This observation has been borne out by the operations at the Healy, AK coal-fired boiler facility. When first implemented, the DSI system at the Healy facility was based on limestone injection. After a period of operation, the limestone-based DSI system was replaced with a Trona-based system to improve performance. The Trona-based system was subsequently replaced with a sodium bicarbonate DSI system to further improve performance. As was the case at Healy, coal-fired boiler installations seem to be moving to use of the sodium sorbents to achieve SO_2 removal efficiencies of at least 40%. Therefore, no additional discussion of calcium sorbents is provided herein.

[8] Ibid (Technical Analysis Report).

1.3.2 *Flue Gas Temperature at the Injection Location*

Flue gas temperature will have a direct effect on reaction kinetics. A higher efficiency can be achieved when DSI is injected at a location where the flue gas temperature is approximately 500° F, and removal becomes less as the injection location is cooler or hotter. When a sorbent particle is introduced into a hot flue gas, it decomposes to sodium carbonate and the surface area of the particle increases. As reported in a recent Technical Report, the particle surface area begins to increase at 300° F (the minimum recommended sorbent injection temperature) and peaks at 500° F (the "optimum" temperature).[9] Above 500° F the particle structure begins to change and particle sintering may begin, effectively decreasing the activity of the particle. As the particle surface areas increases, a greater portion of the sorbent material is available to participate in the reaction with SO_2, thus producing an increased removal rate.

1.3.3 *Sorbent Particle Size*

Sorbent consumption and acid gas removal rates have been improved over the past several years with the understanding of the importance of uniform sorbent particle size and high sorbent surface areas. To effect these improvements, most DSI systems now employ in-line milling equipment for all sodium sorbents.

1.3.4 *Sorbent Injection Rate (or NSR)*

The NSR reflects the sorbent utilization rate, or the efficiency by which the injected sorbent is utilized in the SO_2 removal reaction. All else being equal, the SO_2 removal rate increases (up to an upper limit) as the NSR is increased. In addition to the particle size factor discussed above, sorbent-to-gas mixing and residence time prior to entering the PM control device will influence the NSR needed to achieve a desired removal rate. Poor mixing conditions and low residence (i.e., reaction) times will produce the situation where a greater NSR is needed to achieve the same level of performance as observed in a well-mixed, adequately timed duct system. A DSI cost model defines its typical NSR for milled Trona with an ESP as

[9] Dr. Sahu, Ranajit, Technical Report on Dry Sorbent Injection (DSI) and Its Applicability to TVA's Shawnee Fossil Plant, Commissioned by the Southern Alliance for Clean Energy, Knoxville, TN, April 2013.

1.40 (target removal is 50%), and its typical NSR for milled Trona with a fabric filter as 1.55 (target removal is 70%).[10] These NSR represent sorbent injection rates of 40% and 55% above the stoichiometric amount of Trona needed for the SO_2 reaction. When other than optimum conditions exist for DSI use (such as poor mixing or inadequate residence time), the NSR must be increased to account for less than optimum sorbent utilization. The actual performance of a DSI system can vary from 0% to 90% depending on the NSR and other operating characteristics.[11]

A separate operating issue has been observed when DSI systems operate with a high NSR. As the NSR increases, a brown nitrogen oxide (NOx) plume begins to be generated and emitted from the stack. This situation produces an undesirable environmental impact of using a DSI system.

1.3.5 PM Control Device Type

One of the more influential DSI system parameters is the PM collection system. This influence is important because the sorbent remains available to participate in the SO_2 reaction while in the ESP or fabric filter used to collect the PM in the flue gas. A system that employs a fabric filter will inherently achieve a greater SO_2 removal rate than one that employs an ESP because a dust cake that builds on the surface of the filter bags provides additional surface area upon which the SO_2 can react. Although studies on the effect of bag cleaning mechanisms could not be found, a pulse air jet bag cleaning system would appear to produce a lesser (secondary) SO_2 removal rate than a shaker system due to the fact that the pulse air system is designed to periodically completely break the dust cake from the cloth, as opposed a shaker cleaning system in which some remnant dust particles would remain on the surface and in the weave of the cloth after cleaning.

[10] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology (Final report), prepared for Systems Research and Applications Corporation, March 2013.
[11] Ibid (Sargent & Lundy).

1.3.6 Flue Gas Properties

The ability of DSI system to achieve any reasonable degree of SO_2 control is highly influenced by the presence of other constituents in the gas stream that will compete with the sodium injected into the gas. In the case of coal-fired boiler flue gases, the primary competing constituent is chlorine. Chlorine present in the coal will form HCl in the flue gas and consume a portion of the injected sorbent. Careful consideration of the chlorine content of the coal, therefore, is needed when sizing the system and defining the NSR.

Distribution of flow with the flue gas duct work is important for at least two reasons: 1) the distribution influences in-duct mixing, and 2) flow distribution may contribute to sorbent deposition within the duct or impaction and plating upon the walls. Many DSI equipment vendors offer Computational Fluid Dynamic (CFD) modeling of plant duct flows to predict and enhance sorbent distribution in flue gas, thereby maximizing performance and minimizing sorbent usage.

1.3.7 Site-specific Considerations for Using DSI at Chena

Two aspects of boiler operation at Chena are good for considering a DSI system: 1) the facility uses a fabric filter for PM control, which improves DSI performance by allowing for continued contact between SO_2 and sorbent, and 2) the flue gas temperature entering the fabric filter is approximately 300° F, which is near the minimum recommended temperature at the sorbent inject location. Some aspects of the Chena operation and site, however, are less than optimum for retrofitting a DSI system, and some of these aspects (i.e., constraints) are discussed below.

Stoker Design— Many of the initial DSI systems were demonstrated on fluidized bed combustion units and employed sorbent injection into the boiler combustion zone. Unlike a fluidized bed combustor, the old traveling grate stokers used at Chena are not designed for suspension burning. Sorbent injected into the combustion zone in a stoker unit would settle onto the stoker coal bed and become unavailable for reaction. This would result in dead burning of the sorbent. For this reason, sorbent injection would need to occur outside of the combustion zone in downstream duct locations that are cooler than in the combustion zone. As noted above, however, adequate temperature exists in other duct locations to allow DSI use at Chena.

Alternative DSI System Orientations **—** Three basic DSI system orientations exist at Chena. Sorbent could either be injected into duct work for each individual boiler (four injection locations), a single injection location where all four duct systems converge just prior to entering the fabric filter, or at two locations—one for the large boiler and one for the three combined small boilers. The simplest of these options would be a single injection point. This option could, however, impact sorbent utilization (see NSR discussion below). Regardless of the selected orientation, a DSI system could be provided that employs a single sorbent receiving and storage area and associated conveying system with or without splitters to convey sorbent to more than one injection location. Assuming that the sorbent is milled in-line, immediately prior to injection, at least two sorbent mills would be needed for each injection location (one mill for use and one redundant mill). Therefore, between two and eight sorbent mills (depending on the number of injection points and ease of moving redundant equipment between injection points when needed) would be required depending on the DSI system orientation.

Factors Influencing NSR **—** The congested site layout will potentially adversely impact the amount of sorbent needed (i.e., NSR) to achieve reasonable reductions using DSI. Figure 1 previously showed the arrangement of flue gas duct work for Boiler 1, 2, and 3. Although not visible in Figure 1, these three duct systems combine with the flue gas duct work for Boiler 5 just prior to entering the fabric filter. If a single sorbent injection location is specified, this location would provide a short mixing zone with a low residence time prior to the fabric filter. Approximately 10 ft of duct is available between the location where the flue gas ducts converge and the combined gas enters the fabric filter. Gas velocities between 55 ft per second (ft/s) and 75 ft/s exist at this location, indicating that the sorbent and flue gas would be afforded only between 0.1 and 0.2 seconds of mixing/residence time prior to entering the fabric filter housing. The GVEA Healy plant's Unit #1 (305 MMBtu/hr boiler) has a 100-ft run prior to the baghouse from the injection point. Assuming GVEA maintains similar duct velocity as Chena, the GVEA DSI system operates with a reaction time of 1 or 2 seconds of mixing prior to entering the fabric filter housing. The mixing zone and residence time at the Chena plant would be very short (10 times less) in comparison and will potentially require additional sorbent be injected to achieve any sort of SO_2 removal. This will, in turn, reduce the cost effectiveness of a DSI system (i.e., increase the operating cost and reduce the removal rate).

Sorbent injection into individual boiler duct will eliminate the short mixing zone and residence time, but this equipment orientation may also adversely impact NSR. The flue gas from each boiler goes through several turns (up to seven) prior to entering the fabric filter housing. While this duct orientation yields good mixing, it may also promote particle deposition and plating on to the inside of the duct work, thereby causing some of the injected sorbent to be wasted and unavailable for reaction.

Existing PM Collection and Storage Equipment — Similar to the issues introduced when discussing SDA, additional PM load to the fabric filter and silo would necessitate an increase in electricity consumption and operational maintenance.

Also, potential changes to the constituent loading and leaching characteristics of the ash due to sorbent use could render the ash unsuitable for beneficial use fill material. Aurora currently provides its collected ash to developers in the area for beneficial use as a fill material. The incorporation of sorbent to the ash could alter the properties of the ash such that it no longer meets the metric used to evaluate its benefit. If the ash from the Chena plant were to be treated as a waste product, significant disposal costs would be realized through either coal ash landfill development or tipping fees at the municipal solid waste landfill.

Facility Space Limitations — A DSI system is rather simple and requires lesser space for equipment than does a SDA system. Eielson Air Force Base (EAFB) recently installed new 120,000 lb/hr steam boilers which were designed with DSI to mitigate sulfate emissions. EAFB uses sodium bicarbonate as the sorbent, which they receive via rail from Solvay Chemical in Wyoming. The system includes two silos with storage capacity of 518 tons each for the sorbent. Each silo is 37 ft tall with a diameter of 21 ft and a 70 inch cone. The silos each hold a volume of 16,777 ft^3. EAFB's current rate of sorbent utilization is 1 lb of sorbent/1,600 lb of steam. At that rate, Aurora could expect a maximum use of 220 lb of sorbent/hr (350,000 lb steam/hr). The location of the injection point is at the outlet breaching of the boiler and the temperature of the flue gas at that point is 450°F. As previously discussed, 500°F at the injection point is optimal. While the silos do not occupy an extremely large area, the only available area on the Chena site would be in the northwest corner of the property. An adequate space exists in the northwest portion of the Chena site, but space for truck traffic to deliver the sorbent is extremely limited and may prevent actual truck movement in this area of the facility. Sorbent receiving would likely be sited north of the Chena River along with the coal receiving facilities. Sorbent would have to be received by rail or truck and conveyed across the river to storage silos on the south side of the river.

1.4 *REVIEW OF SO_2 BACT DATABASE*

The RACT/BACT/LAER (RBLC) Clearinghouse was searched again for this addendum (an original search was conducted and reported in the original BACT report) to identify similar sources with SO_2 BACT determinations within the past 10 years. The RBLC Clearinghouse lists 23 facilities with large (i.e., greater than 250 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations and two facilities with small (i.e., less than 100 MMBtu/hr) coal-fired boilers with SO_2 BACT determinations. Table 1 summarizes the projects in the database search that are pertinent to the Chena Power Plant BACT Analysis. One additional facility is included, the Healy Power Plant, but was not identified in the RBLC search. When looking at reported performance at existing operations, one must acknowledge that the level of control claimed at existing facilities using SDA and DSI or as reported in the Clearinghouse database may not have actually been demonstrated by the facility and may not be achievable at the Chena facility. Additionally, other systems may have been installed that are not yet included in the RBLC Clearinghouse.

Ten of the 23 determinations for large boilers were for SDA and/or DSI systems, and the range of control reported for these determinations was:

- SDA: 0.06 to 0.10 lb/MMBtu (five facilities)
- DSI: 0.035 to 0.3 lb/MMBtu (four facilities)
- Combination SDA/DSI: 0.055 to 0.075 lb/MMBtu (three facilities)

Table 1. Summary of SO_2 BACT Permit Reviews

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description: Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection(1)	Circulating Dry Scrubber	Emission Limit
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, >250 MMBtu/hr Pollutant Name = SO_2	AR-0094	John W. Turk Power Plant	11/5/2008	6,000 MMBtu/hr PRB sub-bituminous pulverized coal (PC) boiler							X			0.08 lb/MMBtu, 30-day average (0.065 lb/MMBtu when burning coal <= 0.45% by weight sulfur content. (PSD and Case-by-Case MACT permit decision.)
	AZ-0055	Navajo Generating Station	2/6/2012	3, 7,725 MMBtu/hr PC boilers						X				
	CA-1206	Stockton Cogen Company	9/16/2011	730 MMBtu/hr coal-fired circulating fluidized bed (CFB) boiler								X		70% removal (3-hr average)
	IA-0091	Ottumwa Generating Station	2/27/2007	6,370 MMBtu/hr coal-fired Boiler #1		X								1.2 lb/MMBtu, 3-hr rolling average (Wet FGD rejected at $29,797/ton (2007 dollar basis).)
	KY-0100	J.K. Smith Generating Station	4/9/2010	3,000 MMBtu/hr CFB boilers CFB1 and CFB2							X	X		0.075 lb/MMBtu, 30-day average (Based on PRB coal - 0.54% S; bituminous coal - 1.58% S; and 1.4 lb SO_2/MMBtu at wet FGD inlet.) Permit terminated due to legal challenge.
	MI-0389	Karn Weadock Generating Complex	12/29/2009	8,190 MMBtu/hr PRB coal or 50/50 blend PC boiler (fuel to meet 1.4 lb SO_2/MMBtu at FGD inlet)		X		X						0.06 lb/MMBtu, 30-day rolling average
	MI-0399	Detroit Edison--Monroe	12/21/2010	7,624 MMBtu/hr coal-fired Boiler Units 1, 2, 3 and 4			X							0.107 lb/MMBtu each, 24-hr rolling average
	MI-0400	Wolverine Power	6/29/2011	2, 3,030 MMBtu/hr, petcoke/coal-fired CFB Boilers (CFB1 & CFB2) (Excluding Startup & Shutdown)							X			0.06 lb/MMBtu, 30-day rolling average; excluding startup & shutdown
	MO-0077	Norborne Power Plant	2/22/2008	Supercritical PC boiler with steam turbine generator with a nominal net electric output of 689 MW					X					
	ND-0024	Spiritwood Station	9/14/2007	1,280 MMBtu/hr lignite coal-fired atmospheric CFB boiler							X	X		0.06 lb/MMBtu, 30-day rolling average; 98.7% removal for worst case 30-day lignite; 98.8% removal for worst case 24-hr lignite

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description: Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	Emission Limit
	OH-0310	American Municipal Power Generating Station	10/8/2009	2, 5,191 MMBtu/hr, PC boilers			X							0.15 lb/MMBtu, 30-day rolling average; 0.184 lb/MMBtu, 24-hr rolling average; 0.2400 lb/MMBtu, 3-hr average Admin permit mod 10/09 to add Case-by-Case MACT for Boilers
	OH-0314	Smart Papers Holdings, LLC	1/31/2008	420 MMBtu/hr coal-fired pulverized dry bottom boiler and 249 MMBtu/hr coal-fired spreader stoker coal-fired boiler										1.7 lb/MMBtu
	OK-0118	Hugo Generating Station	2/9/2007	750 MW coal-fired steam EGU boiler (HU-Unit 2)			X							0.065 lb/MMBtu, 30-day rolling average
	PA-0257	Sunnyside Ethanol, LLC	5/7/2007	496.8 MMBtu/hr coal-fired CFB boiler					X			X		0.2 lb/MMBtu, 30-day rolling average
	TX-0554	Coleto Creek Unit 2	5/3/2010	6,670 MMBtu/hr PRB coal-fired Boiler Unit 2							X			0.06 lb/MMBtu, 30-day rolling average
	TX-0577	White Stallion Energy Center	12/16/2010	3,300 MMBtu/hr coal & pet coke-fired CFB Boiler							X			0.114 lb/MMBtu pet coke, 30-day rolling average; 0.086 lb/MMBtu, pet coke 12-mo rolling average; 0.063 lb/MMBtu coal, 30-day and 12-mo rolling average
	TX-0585	Tenaska Trailblazer Energy Center	12/30/2010	8,307 MMBtu/hr sub-bituminous coal-fired boiler			X							0.06 lb/MMBtu, 30-day rolling average
	TX-0593	Texas Clean Energy Project	12/28/2010	400 MW PRB coal-fired Integrated Gasification Combined Cycle power plant	X									10 ppm sulfur in syngas
	TX-0601	Gibbons Creek Steam Electric Station	10/28/2011	5,060 MMBtu/hr coal-fired boiler			X							1.2 lb/MMBtu
	UT-0070	Bonanza Power Plant Waste Coal Fired Unit	8/30/2007	2, 1,445 MMBtu/hr waste coal/bituminous blend-fired CFB boiler							X	X		0.055 lb/MMBtu, 30-day rolling average
	VA-0311	Virginia City Hybrid Energy Center	6/30/2008	2, 3,132 MMBtu/hr coal and coal refuse-fired CFB boilers (Sulfur content of coal/coal refuse to CFB boilers not to exceed 2.28% as-fired and 1.5% on annual basis)								X		0.035 lb/MMBtu, 3-hr average; 0.029 lb/MMBtu, 24-hr average; 0.022 lb/MMBtu, 30-day rolling average
	WY-0063	Wygen 3	2/5/2007	1,300 MMBtu/hr sub-bituminous coal-fired PC boiler					X					0.09 lb/MMBtu, 12-mo rolling average
	WY-0064	Dry Fork Station	10/15/2007	Coal-fired PC Boiler (ES1-01)									X	0.07 lb/MMBtu, 12-mo rolling average

Table 1. Summary of SO_2 BACT Permit Reviews (continued)

Search Criteria	Facility ID	Facility Name	Permit Issuance	Process Name	Control Method Description: Combustion Practices	Low Sulfur Coal	Wet FGD	Limestone Forced Oxidation	Dry FGD	FGD - Scrubber	Dry FGD - Spray Dry Adsorber	Limestone Injection[1]	Circulating Dry Scrubber	Emission Limit
	N/A (not in RBLC)	Golden Valley Electric Association – Healy Power Plant (HPP)	11/19/2012 Consent Decree and 4/14/2014 Minor Permit	2, existing PC-fired steam generators: a 25 MW Foster-Wheeler Boiler (Unit #1) and a 50 MW TRW Entrained Combustion System PC-fired steam generator (Unit #2).								X		Unit #1 (DSI system): - Improve existing DSI system no later than 9/30/2015 or 18 months after Unit #2 first fires coal after 11/19/2012 whichever is later. - After 1/1/2016, SO_2 emission limit of 0.30 lb/MMBtu, 30-day rolling average
											X			Unit #2 (SDA system): - SO_2 emission limit of 0.10 lb/MMBtu, 30-day rolling average
Permit Date = 1/1/2007 to 10/24/2017 Process = coal-fired, <100 MMBtu/hr	OH-0315	New Steel International Inc., Haverhill	5/6/2008	6, 60 MMBtu/hr waste heat, PC boilers							X			0.1760 lb/MMBtu as a rolling 3-hour average The facility is non-attainment for $PM_{2.5}$ and PSD for PM, PM_{10}, CO, NOx, SO_2, and VOC. A production rate restriction on the electric arc furnaces was requested to keel lead below PSD and Title V thresholds. PM_{10} was used as the limit in the permit. However, since $PM_{2.5}$ was used for all LAER determinations the limits were entered under $PM_{2.5}$ instead.
Pollutant Name = SO_2	VA-0309	Georgia Pacific Wood Products - Jarratt	5/15/2008	86.6 MMBtu/hr coal-fired Keeler Boiler	X	X								

1. Limestone Injection presumed to be equivalent to DSI.

It should be noted that SDA or DSI were required only on circulating fluidized bed (CFB) or pulverized coal (PC) boilers. In contrast, the Chena boilers are stoker boilers for which the boiler operation is quite different than a CFB or PC boiler and present unique retrofit challenges. In addition, the sizes of these units range from approximately 2 to 25 times larger than the large Chena boiler.

One small boiler was identified with an SDA system required to meet 0.1760 lb SO_2/MMBtu.

1.5 SUMMARY OF TECHNICAL FEASIBILITY

Regardless of the achievable level of control afforded by a dry scrubbing system, this control technology (SDA and DSI) is considered technically feasible for controlling SO_2 emissions from coal fired boilers, and the RBLC identifies several in use on larger coal-fired boilers. A detailed evaluation of constraints posed by site-specific factors, however, is needed before either specific technology can be considered feasible for use at the Chena facility. These detailed site-specific evaluations/design factors are beyond the scope of the current BACT analysis.

In the absence of a detailed control system design for Chena, a level of 0.10 lb SO_2/MMBtu was selected for SDA for the BACT analysis, which is comparable with that required for the Healy Unit #2. This represents a 74% reduction from Aurora's actual SO_2 emission rate of 0.39 lb/MMBtu. Independent discussions with SDA equipment vendors, however, indicate that vendors do not like to select design removal rates above 0.12 lb/MMBtu (equivalent to 70% removal). The Healy performance requirement is considered most relevant to Chena because the boilers at Healy are of similar size to Chena's and the coal feed is the same.

Selection of an appropriate design basis for a DSI system for Chena is much less straight forward. One primary reason is that DSI systems reported in the RBLC Clearinghouse are for lime injection into fluidized bed combustors, which are very different that the Chena stokers. A DSI system performance level of 0.30 lb SO_2/MMBtu has been specified for the Healy DSI system, representing a 23% reduction from average uncontrolled SO_2 emissions. Interestingly, the Technical Analysis Report (TAR) for Healy Permit AQ0173MSS0, which requires the facility to "improve" the DSI system performance currently on Healy Unit No. 1, specifies the improved emission rate of 0.30 lb SO_2/MMBtu. This statement in the TAR, therefore, suggests that the original Healy DSI system was achieving less than 23% reduction of SO_2. Literature, however, commonly reports a lower end of DSI system performance at 40%, and discussions with vendors indicate that this level of removal (without knowing the exact coal used) is generally achievable using DSI. Because of discrepancies in reported DSI system performance, therefore, one could easily define DSI system performance when using Usibelli coal as less than 23% removal. For the current assessment, DSI system performance was selected to be between 0.23 and 0.30 lb SO_2/MMBtu (i.e., between 23% and 40% removal).

2 ECONOMIC EVALUATION OF SO_2 CONTROL OPTIONS

Despite the technical challenges described in Section 1 associated with installation of SDA or DSI at the Chena Power Plant, an economic evaluation was prepared for each technology under the assumption that these challenges could possibly be mitigated during a detailed design.

2.1 SDA ECONOMIC EVALUATION

Capital and operating costs associated with the installation of a SDA system are based on cost estimating procedures developed by U.S. EPA in the Coal Utility Environmental Cost (CUECost) tool. The CUECost tool is an Excel workbook (an interrelated set of spreadsheets) that produces rough-order-of-magnitude (ROM) cost estimates (+/-30% accuracy) of the installed capital and annualized operating costs for air pollution control systems installed on coal-fired power plants, including those to control emissions of SO_2. The SO_2 emission control technologies currently in the workbook include: limestone FGD system with forced oxidation (i.e., wet scrubber) and lime spray drying FGD system (i.e., dry scrubber).

The wet scrubber portion of the CUECost tool was used in the original BACT Analysis. The spray drying portion of the tool was used for this addendum and was used for two scenarios – control of the combined boiler exhaust and control of the large boiler exhaust only. The CUECost tool included the following site-specific information:

- Net Plant Heat Rate (Btu/kWhr) = 11,571
- Retrofit Factor = 2.0 (difficult)
- Coal ultimate and proximate analysis data and ash analysis data obtained from http://www.usibelli.com/Coal-data.php
- Site specific SO_2 emission rate
  - Combined exhaust = 0.39 lb SO_2/MMBtu
  - Large boiler only = 0.32 lb SO_2/MMBtu
- Reagent price is $215/ton delivered
- Cost basis = 2015
- SO_2 removal required = 74 percent
- Annual SO_2 removed based on full load at 8,760 hr/year

All other values used were default values.

No attempt was made to incorporate location-specific cost adjustment factors into the CUECost tool.

The cost-effectiveness of the SO_2 control system is calculated in the CUECost tool by dividing the total annual cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 2 presents a summary of the CUECost inputs and calculation summary for the lime spray dryer scrubber.

Table 5 presents the cost effectiveness of the SDA technology (as well as the DSI technology discussed in the next section).

2.2 *DSI ECONOMIC EVALUATION*

Capital and operating costs associated with the installation of a DSI system are based on a DSI cost model developed by Sargent & Lundy and referred to as the IPM Model.[12] In developing the IPM Model, the authors reviewed cost data for several DSI systems and developed a relationship for the capital costs based on the sorbent feed rate. The Total Project Cost output by the IPM Model includes the base installed cost, the fixed operating and maintenance (O&M) cost, and the variable O&M cost. The base installed cost includes:

- All equipment
- Installation
- Buildings
- Foundations
- Electrical
- Retrofit difficulty factor
- Engineering and construction management

The Model uses 2012 pricing. Escalation is not included in the estimate.

[12] Ibid (Sargent & Lundy).

Table 2. CUECost Input and Calculation Summary for SDA

CUECost			
Coal Utility Environmental Cost			
Version 1, November 25, 1998 (revised 2-9-00 as CUECost3.xls)			
APC Technology Choices			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
FGD Process	Integer	2	2
(1 = LSFO, 2 = LSD)			
Particulate Control	Integer	1	1
(1 = Fabric Filter, 2 = ESP)			
INPUTS			
Description	**Units**	**Combined Exhaust**	**Large Boiler only**
General Plant Technical Inputs			
Location - State	Abbrev.	AK	AK
MW Equivalent of Flue Gas to Control System	MW	142.4	74.6
Net Plant Heat Rate	Btu/kWhr	11,571	11,571
Plant Capacity Factor	%	65%	65%
Total Air Downstream of Economizer	%	120%	120%
Air Heater Leakage	%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350
Inlet Air Temperature	°F	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013
Ash Split:			
Fly Ash	%	40%	40%
Bottom Ash	%	60%	60%
Seismic Zone	Integer	1	1
Retrofit Factor	Integer	2	2
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	8
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No
Economic Inputs			
Cost Basis -Year Dollars	Year	2015	2015
Sevice Life (levelization period)	Years	10	10
Inflation Rate	%	3%	3%
After Tax Discount Rate (current $'s)	%	9%	9%
AFDC Rate (current $'s)	%	11%	11%
First-year Carrying Charge (current $'s)	%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%
Sales Tax	%	6%	6%
Escalation Rates:			
Consumables (O&M)	%	3%	3%
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	578.4	578.4
If "No" input escalation rate.	%	3%	3%
Construction Labor Rate	$/hr	$60	$60
Prime Contractor's Markup	%	3%	3%
Operating Labor Rate	$/hr	$63	$63
Power Cost	Mills/kWh	25	25
Steam Cost	$/1000 lbs	3.5	3.5

Note: 'MW Equivalent of Flue Gas to Control System' is heat input capacity converted to MW.

Lime Spray Dryer (LSD) Inputs			
SO2 Removal Required **(removal required to reach 0.1 lb/MMBtu)**	%	74%	69%
Adiabatic Saturation Temperature	°F	127	127
Flue Gas Approach to Saturation	°F	20	20
Spray Dryer Outlet Temperature	°F	147	147
Reagent Feed Ratio	Factor	0.76	0.70
(Mole CaO / Mole Inlet SO2)			
Recycle Rate	Factor	30	30
(lb recycle / lb lime feed)			
Recycle Slurry Solids Concentration	Wt. %	35%	35%
Number of Absorbers	Integer	1	1
(Max. Capacity = 300 MW per spray dryer)			
Absorber Material	Integer	1	1
(1 = alloy, 2 = RLCS)			
Spray Dryer Pressure Drop	in. H2O	5	5
Reagent Bulk Storage	Days	60	60
Reagent Cost (delivered)	$/ton	$215	$215
Dry Waste Disposal Cost	$/ton	$30	$30
Maintenance Factors by Area (% of Installed Cost)			
Reagent Feed	%	5%	5%
SO2 Removal	%	5%	5%
Flue Gas Handling	%	5%	5%
Waste / Byproduct	%	5%	5%
Support Equipment	%	5%	5%
Contingency by Area (% of Installed Cost)			
Reagent Feed	%	20%	20%
SO2 Removal	%	20%	20%
Flue Gas Handling	%	20%	20%
Waste / Byproduct	%	20%	20%
Support Equipment	%	20%	20%
General Facilities by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%
Engineering Fees by Area (% of Installed Cost)			
Reagent Feed	%	10%	10%
SO2 Removal	%	10%	10%
Flue Gas Handling	%	10%	10%
Waste / Byproduct	%	10%	10%
Support Equipment	%	10%	10%

SUMMARY OF COSTS

Description	Units	Combined Exhaust	Large Boiler only
APC Technologies			
SO2 Control		LSD	LSD
		Combined Exhaust	**Large Boiler only**
SO2 Control Costs		**LSD**	**LSD**
Total Capital Requirement (TCR)	$	$74,161,357	$62,173,057
	$/kW	$521	$833
First Year Costs			
Fixed O&M	$	$3,709,418	$2,767,988
	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$	$415,100	$203,435
	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$	$16,537,983	$13,864,592
	$/kW-Yr	116.14	185.85
	Mills/kWH	20.40	32.64
	$/ton SO2 removed	$41,415.5	$86,909.6
TOTAL	$	$20,662,501	$16,836,015
	$/kW-Yr	145.10	225.68
	Mills/kWH	25.48	39.64
	$/ton SO2 removed	$51,744	$105,536
Levelized Current Dollars			
Fixed O&M	$/kW-Yr	30.11	42.89
	Mills/kWH	5.29	7.53
	$/ton SO2 removed	$10,737.6	$20,056.1
Variable O&M	$/kW-Yr	3.37	3.15
	Mills/kWH	0.59	0.55
	$/ton SO2 removed	$1,201.6	$1,474.0
Fixed Charges	$/kW-Yr	88.01	140.85
	Mills/kWH	15.46	24.74
	$/ton SO2 removed	$31,386.6	$65,864.3
TOTAL	$/kW-Yr	121.49	186.89
	Mills/kWH	21.34	32.82
	$/ton SO2 removed	$43,325.8	$87,394.4
Levelized Constant Dollars			
Fixed O&M	$/kW-Yr	26.05	37.10
	Mills/kWH	4.57	6.52
	$/ton SO2 removed	$9,289.4	$17,351.0
Variable O&M	$/kW-Yr	2.92	2.73
	Mills/kWH	0.51	0.48
	$/ton SO2 removed	$1,039.5	$1,275.2
Fixed Charges	$/kW-Yr	60.93	97.51
	Mills/kWH	15.20	24.32
	$/ton SO2 removed	$30,863.7	$64,767.1
TOTAL	$/kW-Yr	89.90	137.34
	Mills/kWH	20.29	31.32
	$/ton SO2 removed	$41,192.6	$83,393.3

The O&M cost includes:

- Fixed
  - Operating labor for the DSI system (two operators needed)
  - Maintenance materials and labor
  - Administrative labor
- Variable
  - Sorbent use
  - Waste production and disposable cost
  - Additional required power

The IPM Model used for this addendum included two equipment orientations: 1) sorbent injection into the combined boiler exhaust just immediately prior to the fabric filter, and 2) sorbent injection into the individual exhaust from the large boiler near the combustion zone. The IPM Model tool included the following site-specific information:

- Gross heat input
  - Combined = 486 MMBtu/hr
  - Large boiler = 255 MMBtu/hr
  - Small boilers = 77 MMBtu/hr each
- Retrofit Factor = 2.0 (difficult)
- Location Adjustment Factor = 2.2 (for Fairbanks, Alaska)
  - The location adjustment factor (LAF) is applied to the base installed cost and reflects the average statistical differences in normal labor, material, and equipment costs for similar facilities built in different geographical locations. The factor also makes allowances for weather, seismic, climatic, normal labor availability, labor productivity, life support/mobilization, and contractor's overhead and profit conditions. The factor does not reflect abnormal differences due to unique site consideration, such as historical preservation.[13] (The CUECost model has no way to accommodate this factor, and LAF was not applied for SDA.)
- Site specific SO_2 emission rate
  - 0.39 lb/MMBtu (combined)
  - 0.32 lb/MMBtu (large boiler only)
  - 0.49 lb/MMBtu (each small boiler)

[13] Programming Cost Estimates for Military Construction, UFC3-370-01, 6 June 2011.

- Cost Basis = 2015
- SO_2 removal required = 40 percent
- Annual SO_2 removed based on full load at 8,760 hr/year
- Minimum Normalized Stoichiometric Ratio (NSR) = 1.5 (to account for less than optimum mixing and residence time in the combined orientation; deposition in the individual orientation; and breaking the filter cake in all orientations.
- Sorbent price based on delivered price paid by Healy in 2015/2016

All other values used were default values.

The cost-effectiveness of the SO_2 control system is calculated in the IPM Model by dividing the total annualized operating cost by the annual (potential) tons of pollutant removed. Costs were corrected to 2015 dollars using the Chemical Engineering Composite Price Index. Table 3 and Table 4 present summaries of the IPM Model inputs and cost effectiveness calculation summaries for the DSI system.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	142.4	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.39	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	486,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for less than optimum mixing and residence time in the combined orientation and breaking the filter cake in all orientations)
Trona Feed Rate	M	(ton/hr)	0.34	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.246	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.90	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.05	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\2/, UFC 3-701-01, Change 8, July 2015.
IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.				

Capital Cost Calculation (2012 dollars)			Comments
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty			
Base Module (BM) ($)	=	$ 26,915,857	Base DSI module includes all equipment from unloading to injection
Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284)			
Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)			
Total Project Cost			
A1 = 5% of BM	=	$ 1,345,793	Engineering and construction management costs
A2 = 5% of BM	=	$ 1,345,793	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM	=	$ 1,345,793	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	$ 30,953,236	Capital, engineering, and construction costst subtotal
B1 = 5% of CECC	=	$ 1,547,662	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	$ 32,500,898	Total project cost without AFUDC
B2 = 0% of (CECC + B1)	=	0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$ 32,500,898**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Table 3. Annualized Cost Summary for DSI for the Combined Boiler Exhaust (continued)

Direct Annual Costs			
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$ 1.84	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$ 0.95	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$ 0.07	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$ 2.85**	**Total Fixed O&M costs**
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	=	$ 1.08	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$ 0.40	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$ 0.045	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$ 1.53**	
Indirect Annual Costs			
Overhead (80% of total operation and maintenance labor)	=	$ 324,909	
Administrative charges (2% of total capital investment)	=	$ 650,018	
Insurance (1% of total capital investment)	=	$ 325,009	
Property tax (1% of total capital investment)	=	$ 325,009	
Capital recovery	=	$ 5,289,521	
(16.275% of total capital investment: 10 yr at 10% interest)			
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$ 6,914,466**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$ 9,227,624**	
Composite CE Index for 2012 (cost year of equation)	=	584.6	
Composite CE Index for 2015 (cost year of review)	=	578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$ 9,129,760**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=	830	
SO_2 REMOVAL EFFICIENCY, %	=	40	
TOTAL SO_2 REMOVED, tons	=	332	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$ 27,493**	

Table 4. Annualized Cost Summary for DSI for the Large Boiler Exhaust

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	74.6	<-- User Input
Retrofit Factor	B		2	<-- User Input (An "average" retrofit has a factor of 1.0.)
Gross Heat Rate	C	(Btu/kWh)	3,415	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.32	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	40	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90%
Heat Input	J	(Btu/hr)	255,000,000	A*C*1000 or **User Input**
NSR	K		1.50	1.5 (to account for deposition in the individual orientation)
Trona Feed Rate	M	(ton/hr)	0.147	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.106	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM?	P	(ton/hr)	0.47	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 **Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560**
Aux Power Include in VOM?	Q	(%)	0.04	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	451	<-- User Input (based on delivered price paid by Healy)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.09385	<-- User Input
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits)
Location Adjusment Factor	LAF		2.2	Factor applied to Base Module Cost - Location Adjusment Factor for Fairbanks, AK from DoD Facilities Pricing Guide\2\/2/, UFC 3-701-01, Change 8, July 2015.
IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA.				

Capital Cost Calculation (2012 dollars)				**Comments**
Includes - Equipment, installation, building, foundations, electrical, and retrofit difficulty				
Base Module (BM) ($)	=	$	21,186,595	Base DSI module includes all equipment from unloading to injection
Unmilled Trona = IF(M>25,(745000*B*M*LAF),(7500000*B*LAF*M^0.284)				
Milled Trona = IF(M>25,(820000*B*M*LAF),(8300000*B*LAF*M^0.284)				
Total Project Cost				
A1 = 5% of BM	=	$	1,059,330	Engineering and construction management costs
A2 = 5% of BM	=	$	1,059,330	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 5% of BM	=	$	1,059,330	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	$	24,364,585	Capital, engineering, and construction costst subtotal
B1 = 5% of CECC	=	$	1,218,229	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	$	25,582,814	Total project cost without AFUDC
B2 = 0% of (CECC + B1)	=		0	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**25,582,814**	**Total project cost**

Note: 'Unit Size (Gross)' is heat input capacity converted to MW.

Direct Annual Costs			
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$ 3.51	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$ 1.42	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$ 0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$ 5.06**	**Total Fixed O&M costs**
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	=	$ 0.889	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$ 0.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	=	$ 0.037	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$ 1.31**	
Indirect Annual Costs			
Overhead (80% of total operation and maintenance labor)	=	$ 301,717	
Administrative charges (2% of total capital investment)	=	$ 511,656	
Insurance (1% of total capital investment)	=	$ 255,828	
Property tax (1% of total capital investment)	=	$ 255,828	
Capital recovery	=	$ 4,163,603	
(16.275% of total capital investment: 10 yr at 10% interest)			
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$ 5,488,633**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$ 6,723,906**	
Composite CE Index for 2012 (cost year of equation)	=	584.6	
Composite CE Index for 2015 (cost year of review)	=	578.4	
TOTAL ANNUALIZED OPERATING COSTS (2015 $)	**=**	**$ 6,652,596**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=	357	
SO_2 REMOVAL EFFICIENCY, %	=	40	
TOTAL SO_2 REMOVED, tons	=	143	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$ 46,534**	

Table 5 presents a summary of the cost effectiveness of all SO_2 control options considered, including the wet scrubber considered in the original BACT Analysis. As seen in the individual cost model spreadsheets, the model-derived cost-effectiveness values are based on the potential SO_2 emissions from the Chena boilers. The combined SO_2 emission rate from all four boilers is equal to 814.5 tons/yr (potential) and 700 tons/yr (actual). The value for actual emissions is based 1.9 tons SO_2 per day as specified in the State Implementation Plan (SIP). Therefore, to derive cost-effectiveness values based on actual expected SO_2 reductions, the cost-effectiveness values output by the cost models were adjusted by the ratio of actual emissions to potential emissions.

Table 5 presents the calculated SO_2 removal cost effectiveness on both a potential emission reduction and actual emission reduction basis. These values are not considered cost effective for the retrofit options at Chena Power Plant.

Table 5. Summary of Cost Effectiveness of SO_2 Control Options

Rank	Control Option	Control Orientation	Cost Effectiveness ($ per year/ ton per year removed		Expected SO_2 Emission Rate (lb/MMBtu)
			Potential	Actual	
1	Low sulfur coal	combined exhaust	(already used)		0.39
2	Dry scrubber – DSI	combined exhaust	27,493	31,990	0.23 (40% removal)
3	Dry scrubber – SDA	combined exhaust	41,193	47,931	0.10 (74% removal)
4	Dry scrubber – DSI	large boiler only	46,534	54,146	0.19 (40% removal)
5	Wet scrubber	combined exhaust	75,672	88,050	0.20 (50% removal)
6	Dry scrubber – SDA	large boiler only	83,393	97,034	0.10 (69% removal)

3 DISCUSSION OF SITE-SPECIFIC TECHNICAL, ENVIRONMENTAL, AND ENERGY ASPECTS OF DRY SCRUBBING TECHNOLOGY USE AT CHENA POWER PLANT

3.1 SUMMARY OF TECHNICAL FEATURES AND CHALLENGES

Table 6 presents a summary of some technical features of SDA and DSI technologies evaluated herein and some challenges associated with their potential use at Chena. Section 1 of this report identified several SDA and DSI applications for coal-fired boilers. The quality of the information varies considerably, and the information acquired was used as best as possible to hypothesize performance expectations from each evaluated technology. Nonetheless, no true assurances exist that the evaluated technologies will actually perform as stated when applied to the Chena facility. While the technical concepts are valid, demonstration of the technology employed as retrofit technology on units and equipment orientations such as those observed at the Chena facility cannot reliably be predicted, thus raising doubts over the accuracy of technology transfer, particularly for sorbent injection. Perhaps the best example of this uncertainty can be found when reviewing the history of the DSI system operation at the Healy Power Plant in Healy, AK. The subject of a Consent Decree, Healy was ordered to “improve” the DSI system in use on Unit No. 1 to achieve a controlled SO_2 emission rate of 0.30 lb/MMBtu. Even with extensive testing under the US Department of Energy Clean Coal program, this marginal mandated performance level is indicative of technological uncertainties associated with retrofit technology applied to control coal-fired boiler emissions.

Coupled with the technological uncertainties associated with these technologies applied as a retrofit solution are other factors that obscure the practicality of applying retrofit dry scrubber technology at the Chena facility. One of these factors, the economics of the technologies, was discussed in detail in Section 2 of this report and led to the observation that application of SDA or DSI at Chena was not a cost-effective means to reduce SO_2 emissions. Other factors, discussed in the following sections, include:

- Facility location limitations
- Environmental considerations
- Energy considerations

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant

Factor	Spray Dry Absorber Technology	Dry Sorbent Injection Technology
Demonstrated use under conditions similar to Chena Plant	1. Spray dry absorber technology is available and used to reduce SO_2 emissions from coal-fired boiler flue gas streams. 2. The U.S. EPA's air pollution control cost manual indicates that SDA technology can be reduce SO_2 by 50% up to over 90%. Finding a suitable outlet for the particulate captured in the fabric filter following dry scrubbing is an important consideration to the feasibility of this option.	1. Dry sorbent injection is becoming more prevalent for reducing acid gas concentrations in coal-fired boiler flue gas streams. 2. Although DSI technology is discussed in the industry, the only DSI systems presented in the RBLC Clearinghouse are lime/limestone injection systems into fluidized bed combustors. No DSI systems are listed when the boiler is a stoker, as at Chena. 3. Sorbent injection into the duct work downstream of the coal combustion zone is also becoming more prevalent in the industry, as reported by equipment vendors. No such systems, however, are presented in the RBLC Clearinghouse.
Technical considerations	1. Depending on equipment orientation, a SDA system would lower the flue gas temperature, which could then cause plugging of the downstream fabric filter. 2. A SDA system placed upstream of the fabric filters would potentially contaminate the ash and cause the loss of a useable by-product. 3. A SDA system would require gas reheating to prevent plugging in the fabric filter, thus increasing station service load. 4. The temperature of water used to prepare the lime slurry can impact the hydrated lime reactivity. Adequate facilities must be included (indoors) to prevent issues associated with slurry preparation, delivery, and use. 5. The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved.	1. The existing duct work at Chena is very complicated and winding. Sorbent injection into a section of combined flue gas would have less than optimum mixing and less than 0.2 seconds of residence time prior to entering the fabric filter. These two situations will increase the sorbent consumption rate by reducing sorbent utilization. 2. Sorbent injection into the large boiler alone would provide adequate mixing time, but the flue gas would continue through seven turns in which sorbent loss through deposition on the interior duct work could occur, thus increasing sorbent consumption. 3. The pulse jet cleaning system in the existing fabric filter will periodically break the filter cake, thus temporarily reducing the additional sorbent reaction time with SO_2 and ultimately reducing the overall SO_2 removal that can be achieved. 4. Use of sorbent materials may render the collected ash no longer suitable for use as a fill material. The current beneficial use of collected ash as a fill material would have to be replaced with landfill disposal of the collected PM.

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

<table>
<tr><th>Factor</th><th>Spray Dry Absorber Technology</th><th>Dry Sorbent Injection Technology</th></tr>
<tr><td>Structural considerations</td><td colspan="2">1. The structural stability of the existing ash silo would have to be improved prior to storing any additional PM.
2. Any system placed downstream of the existing fabric filter would necessitate major structural modifications to the existing filter housing to alter the exhaust configuration of the treated flue gas from a monovent, roof monitor arrangement to a gas duct section that delivers gas to the dry scrubber system.</td></tr>
<tr><td rowspan="2">Operational considerations</td><td>1. A SDA system would require additional fans to overcome the increased distance needed to convey the flue gas. The entire air emissions control systems would need to be rebalanced as well. The existing system potentially may not meet design requirements for baghouse air flow.</td><td>1. The history of DSI operation at the Healy facility of GVEA has been anything but stable. The need to retrofit the system on two different occasions draws into question the reliability of the DSI technology.</td></tr>
<tr><td colspan="2">2. The Chena boilers are reaching the end of their useful lives. A life extension study commissioned by Aurora determined that Chena operations could be extended to the year 2030 with expenditure of significant capital. An add-on emission control program aimed at reducing SO_2 emissions over a 10-year period represents an unwise capital expenditure at this time.
3. The U.S. Corps of Engineers estimates that additional construction and operating costs are incurred for projects in Alaska when compared to mainland US. These considerations are difficult to assess in an analysis such as this BACT.
4. .A dry scrubber placed at the outlet of the existing fabric filter would require re-heating the exhaust gases to an optimum temperature; this would reduce steam available for power generation, heating, or station service. A second fabric filter would be then needed to remove the particulate matter formed during scrubbing.
5. The Trona or sodium bicarbonate reagent mill would be required to produce a uniformly-sized sorbent particle prior to use.
6. Reagent receiving and processing would likely require construction of building(s) north of the Chena River and a conveyor over the Chena River. Raw and processed materials would need to be conveyed over relatively long distances.
7. The PM collected in the fabric filter may become a waste product and no longer able to be used as fill.
8. The PM collected in the fabric filter may require pre-treatment prior to disposal as a solid waste.</td></tr>
</table>

Table 6. Summary of Technical Challenges Associated with Dry SO_2 Scrubbing at Chena Power Plant (continued)

<table>
<tr><th>Factor</th><th>Spray Dry Absorber Technology</th><th>Dry Sorbent Injection Technology</th></tr>
<tr><td rowspan="2">Availability of infrastructure and space for equipment</td><td colspan="2">1. A minimal amount of open space is available at the Chena facility to house additional equipment needed to support dry scrubbing technology.</td></tr>
<tr><td>2. The location of a reagent storage area for an SDA system will need to be determined.
3. A preliminary estimate, based on a similarly-sized facility in Colorado, is that the spray tower will need to be at least 40 ft in diameter. The only available space at the Chena facility for this tower would be in the northwest corner of the facility.
4. The flue gas would need to be rerouted approximately 250 ft to the location of the spray tower and then return another 250 ft to the inlet of the fabric filter. This gas rerouting would be needed whether the SDA was oriented as a combined flue gas treatment system or one devoted only to the large boiler. Space for additional fans would then be needed.
5. Availability of land area for the reagent silos and slurry preparation is uncertain.</td><td>2. The short duct run after combination of flue gases makes sorbent inject extremely difficult and leads to poor mixing and short residence time.
3. An area of approximately 50 ft x 50 ft would be needed to house the sorbent receiving and storage area. This area would need to be located in the northwest corner of the facility. This area of the facility has minimal truck traffic at present, and routine deliveries of sorbent by truck would disrupt the normal operations in the area.</td></tr>
</table>

These factors are discussed in the following sections. These factors also were discussed in the original BACT Analysis, and some of the discussion presented below is taken from the original analysis.

3.2 *LOCATION CONSIDERATIONS*

Several issues related to space limitations at Chena were presented in Section 1 or this report. An important aspect of operating on an older, small industrial site is the ability to actually place additional equipment needed to operate add-on control equipment. The SDA and DSI technologies require installation of silos for reagent storage, facilities for preparing the sorbent for treatment of the flue gas, and the technology itself must be erected in available space. The congested nature of the existing Chena Power Plant site is such that the retrofit installation costs are likely to be higher than those estimated and presented in the cost tables provided earlier. Additionally, lack of available space on site could make installation of additional equipment completely infeasible. This limitation would not be completely understood prior to preliminary design of any identified system.

Each of the identified SO_2 technologies also requires routine delivery of reagents to operate the system and will require removal of residues produced by the process. The congested nature of the Chena facility makes on-site truck traffic patterns somewhat problematic. Additionally, Fairbanks is approximately 400 miles from Anchorage, which is a logical location for origination of raw materials. Delivery of necessary sorbents over potentially icy roadways may interrupt raw material deliveries to the point where interruptions in plant operations could occur. The hazardous driving conditions also may cause the transportation costs for raw materials or process equipment to be greater than presented in the cost sheets, thereby causing the cost effectiveness of control to be a larger value than calculated.

Climate considerations factor into the BACT evaluation in two ways: 1) climate causes the costs to become inflated due to the need for additional insulation, heated vessels, and heat tracing, and 2) climate affects the ability of the precursor emissions from the Chena Power Plant to react in the atmosphere and form $PM_{2.5}$. However, no site factors are included in the SDA control cost calculations. Thus, the SDA SO_2 control costs, while already extremely high, may be underestimated. The atmospheric factor, which may limit atmospheric reaction rates, is briefly discussed in the next section on environmental considerations.

3.3 *ENVIRONMENTAL CONSIDERATIONS*

Environmental factors must be considered in a BACT evaluation. With respect to nonattainment BACT, precursor control options that are determined to be economically feasible may not yield the desired objective of improving $PM_{2.5}$ air quality. (This statement is true even though none of the control options evaluated in this BACT evaluation were found to be economically feasible.) A rash conclusion to implement a (economically feasible) precursor control as BACT may in fact produce insignificant environmental benefits and at the same time produce adverse energy or environmental impacts. The environmental topics are discussed below, and energy considerations in the following section. Much of the following discussion was presented in the original BACT Analysis.

The rationale for ensuring that benefits of a precursor control option are indeed real and significant is founded in the Clean Air Act (CAA). CAA section 189(e) explicitly requires that the control requirements applicable for major stationary sources of direct $PM_{2.5}$ emissions must also apply to major stationary sources of $PM_{2.5}$ precursors, unless the state provides a demonstration that emissions of a particular precursor from major stationary sources do not contribute significantly to levels that exceed the standard in the nonattainment area of concern. Thus, the statute generally requires control of all $PM_{2.5}$ precursors in a nonattainment area, but it provides an express exception applicable to major stationary sources in such areas if an appropriate demonstration is made.[14]

A key conclusion derived by looking at the chemical mass balance (CMB) evaluations for PM filters collected in the Fairbanks North Star Borough (FNSB) is that control of Chena Power Plant $PM_{2.5}$ precursors will not provide significant reduction of ambient $PM_{2.5}$. This conclusion can easily be validated by looking solely at the wood smoke contribution and comparing it to the $PM_{2.5}$ standard. As is seen on many episode days, the standard is exceeded solely due to contribution from wood smoke, while the impact of sulfates on episode days is minor.

Although the CMB results included in the SIP provide some insight into establishing source contributions in the FNSB, no straightforward procedures can be used to determine a specific source contribution to ambient $PM_{2.5}$ concentrations and, by extension, the air quality improvements in $PM_{2.5}$ air quality should one or more control measures be implemented at the Chena Power Plant. Because no one procedure answers every question one may have, a variety of procedures are often employed. This is a key issue that relates the magnitude of reductions in daily precursor emissions to commensurate reductions in $PM_{2.5}$ concentrations. In many cases, indirect procedures must be employed to estimate air quality benefits resulting from installation of precursor emission controls. For example, DSI (the SO_2 control option identified herein that has the best cost-effectiveness) was estimated to be able to achieve a 40 percent reduction in SO_2 emissions from the Chena Power Plant boilers. As provided in the background information for the ADEC SIP, on average, Chena Power Plant boilers emitted 1.9 ton/day of SO_2 in 2015 on days when the $PM_{2.5}$ standard was exceeded.[15] Thus, application of DSI at Chena would result in an average SO_2 reduction of 0.76 ton/day.

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[14] Federal Register, Volume 81, page 58091, August 24, 2016, 40 CFR Parts 50, 51, and 93, Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule.

[15] ADEC, Amendments to: State Air Quality Control Plan Volume II: Analysis of Problems, Control Actions; Section III: Area-wide Pollutant Control Program; D: Particulate Matter; 5: Fairbanks North Star Borough $PM_{2.5}$ Control Plan, Section 5.06, page III.D.5.6-27.

This reduction represents only 6.2 percent of the estimated NOx and SO_2 nonattainment area-wide emissions, respectively, estimated to occur on $PM_{2.5}$ episode days in 2008.

ADEC included CMB results in the SIP to provide some insight into establishing source contributions in the FNSB.[16] The CMB analysis estimated a maximum sulfate contribution of 28.8 micrograms per cubic meter (µg/m^3) (at most) in downtown Fairbanks on high $PM_{2.5}$ concentration days between 2005 and 2013. Assuming that all of the precursor emission reductions noted above for Chena Power Plant culminate in the same level of ambient $PM_{2.5}$ reductions, use of DSI technologies at Chena would benefit ambient air quality in downtown Fairbanks by only 1.8 µg/m^3 for sulfates (i.e., 28.8 µg sulfate/m^3 times 6.2 percent reduction in daily SO_2 emissions). The improvements on an average basis would be about half these amounts.

Another environmental factor impacting the true effectiveness of a control option is the atmospheric reaction process that leads to conversion of precursor emissions to $PM_{2.5}$. Three major issues must be considered when evaluating the Chena Power Plant's contribution to $PM_{2.5}$ levels within the FNSB air basin: 1) precursor reaction chemistry in arctic wintertime conditions when exceedances of the $PM_{2.5}$ NAAQS occur, 2) possible increases in nitrate formation as ammonium ions become available, and 3) transport and dispersion of the Chena Power Plant boiler stack plume above and beyond the capped inversion layer that encapsulates the FNSB air basin causing accumulation of ground-level $PM_{2.5}$ within the air basin.

Formation of secondary $PM_{2.5}$ depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity; and the interactions of precursors with preexisting particles and with cloud or fog droplets. The relative contribution to ambient $PM_{2.5}$ concentrations from each precursor pollutant varies by

[16] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-66.

climatological area. The relative effect of reducing emissions of these pollutants is also highly variable.[17]

Sulfates are typically formed in the atmosphere by formation of sulfuric acid from SO_2 that subsequently reacts with ammonia to form ammonium sulfate. There are three different pathways for the transformation of SO_2 to sulfuric acid[18]:

1. Gaseous SO_2 can be oxidized by the hydroxyl radical (OH) to create sulfuric acid. This gaseous SO_2 oxidation reaction occurs slowly and only in the daytime.

2. SO_2 can dissolve in cloud water (or fog or rainwater), and there it can be oxidized to sulfuric acid by a variety of oxidants, or through catalysis by transition metals such as manganese or iron. If ammonia is present and taken up by the water droplet, then ammonium sulfate will form as a precipitate in the water droplet.

3. SO_2 can be oxidized in reactions in the particle-bound water in the aerosol particles themselves. This process takes place continuously, but only produces appreciable sulfate in alkaline (dust, sea salt) coarse particles.

These climatological conditions that are conducive to sulfate formation from transformation of SO_2 are not consistent with the conditions that typically generate high $PM_{2.5}$ concentrations in the FNSB.

Some researchers have reported an increase in nitrate formation associated with ambient SO_2 reductions. This association is strongest in low temperature areas of low humidity and exists because additional ammonium ions will become available for reaction with NOx emissions.[19] Although the net $PM_{2.5}$ concentration will likely be lower after SO_2 reductions, a linear reduction of the ambient $PM_{2.5}$ concentration is not

[17] Federal Register, Volume 73, page 28325, May 16, 2008, 40 CFR Parts 51 and 52, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$).
[18] NARSTO (2004) Particulate Matter Science for Policy Makers: A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 184287 5.
[19] Ibid (NARSTO).

expected, and less $PM_{2.5}$ reduction will be observed than expected because of the increase in the nitrate concentration.

An issue also arises in the FNSB related to the dispersion of precursor emissions from the Chena Power Plant boiler stack and the ability of the dispersed emissions to actually impact the ambient air quality monitors. It has been observed, and it is reasonable to expect, that the boiler stack plume is carried above the winter inversion layer. As such, transport of the precursor pollutants occurs above the inversion layer, where the concentrations of the pollutants can be transported and dispersed by the stronger aloft winds. In addition, the Fairbanks $PM_{2.5}$ Source Apportionment Research Study[20] concluded that dominant aloft wind direction during $PM_{2.5}$ episodes is from the northeast, which would transport the Chena Power Plant emissions away from the ambient air quality monitors located in downtown Fairbanks and North Pole. Figure 2 presents a photograph showing the Chena Power Plant boiler stack exhaust plume height well above the inversion layer. The original BACT Analysis presented an evaluation of Chena coal consumption on high $PM_{2.5}$ concentration days between 2013 and 2015 and revealed a very poor (or no) correlation between Chena Power Plant coal consumption and observed ambient $PM_{2.5}$ levels. This poor correlation is believed to be due to plume entrapment above the wintertime inversion layer.

The poor correlations reported in the original BACT Analysis indicate that changes in Chena Power Plant emissions do not explain the majority of the changes in ambient $PM_{2.5}$ levels. Because the Chena Power Plant emissions are not seemingly influencing the ambient $PM_{2.5}$ concentrations to any significant extent, the ambient levels must be the result of other emission sources in the FNSB.

[20] The Fairbanks, Alaska $PM_{2.5}$ Source Apportionment Research Study Winters 2005/2006-2012/2013, and Summer 2012; Final Report, Amendments 6 and 7, December 23, 2013, Tony J. Ward, Ph.D., University of Montana – Missoula , Center for Environmental Health Sciences.

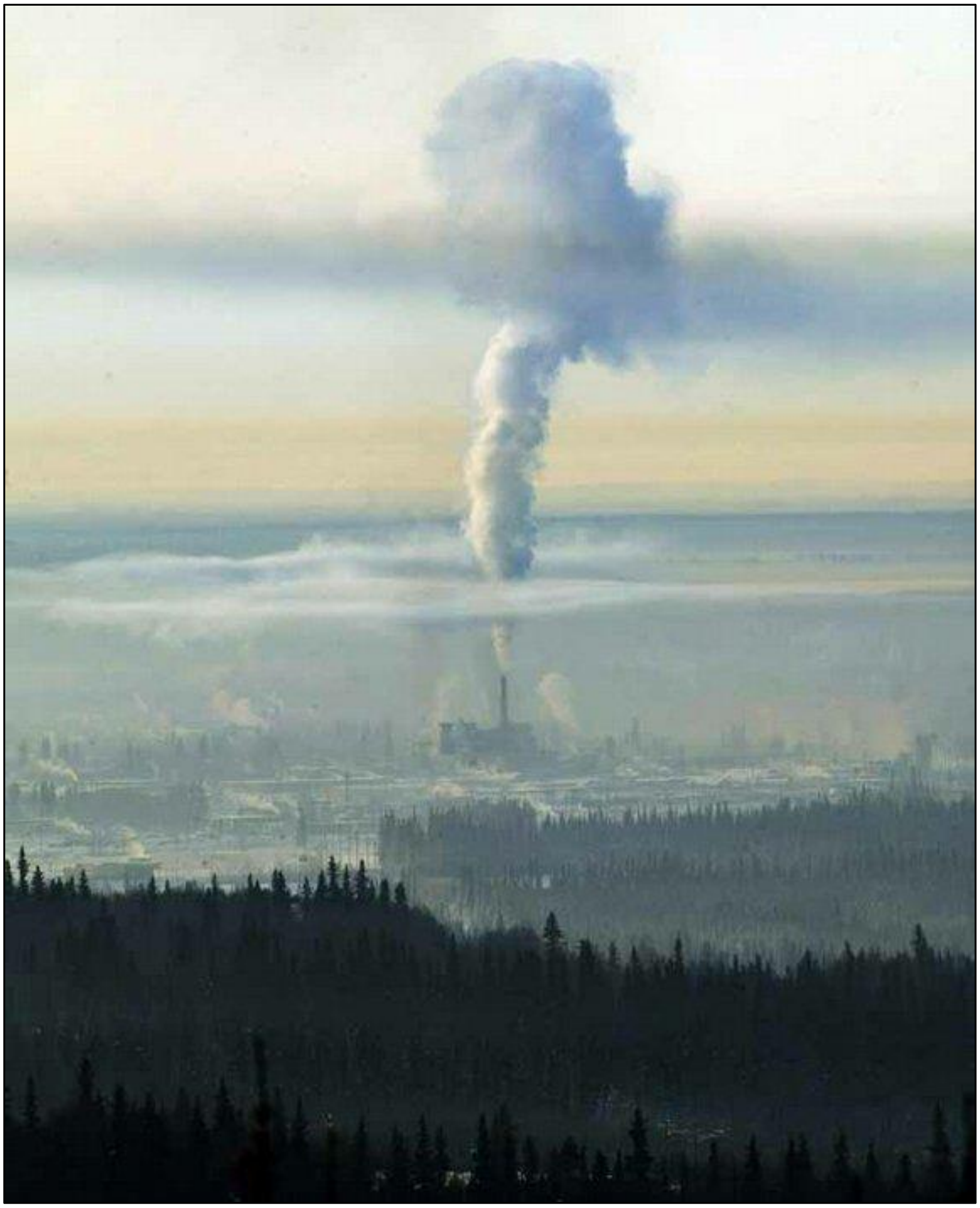

Figure 2. Chena Power Plant exhaust plume.[21]

[21] The exhaust from the Aurora Energy power plant breaks through an inversion layer as seen from the Hagelbarger Road pullout off the Steese Highway. Photo credits: Frank DeGenova, January 30, 2008, http://marcvaldez.blogspot.com/2008/05/wintertime-smokestack-plumes-in.html, accessed December 22, 2017.

This observation can be further illustrated using the following example for the highest $PM_{2.5}$ day (early January) in 2015 at downtown Fairbanks monitors when Chena Power Plant coal consumption was at its greatest rate (2.2 million pounds/day). If this was during one of the coldest days, then the Chena Power Plant impact at ground level would have been less than on other days because: 1) the buoyancy term for the Chena Power Plant boiler plume would be at its greatest because the temperature differential between stack and ambient air temperatures would have been greatest, and 2) the momentum term for the boiler plume would also have been at its greatest because the exhaust gas flow rate would be greater than at lesser coal combustion rates. Because the impact of Chena Power Plant emissions would likely have been less on this episode day than other days, the $PM_{2.5}$ mass on the filters in question would had to have been contributed by other sources in the FNSB.

To summarize these environmental considerations related to photochemistry and precursor transport within the FNSB, the U.S. EPA makes the following corroborating points:

> "Major stationary sources with elevated stacks emit most of their precursors into the extremely stable atmosphere present during wintertime pollution events. Only a fraction of the elevated plumes returns to ground level in the FNSB where air quality monitors are located and much less than might be expected in most parts of the lower 48 states."[22]

In conclusion, and as noted earlier herein, use of DSI technologies at Chena is estimated to benefit ambient $PM_{2.5}$ air quality in downtown Fairbanks by only 1.8 $\mu g/m^3$ at the most due to reduction of ambient sulfates (i.e., 28.8 μg sulfate/m^3 times 6.28 percent reduction in daily SO_2 emissions). The actual improvement will likely be less due to the environmental considerations noted herein. The maximum estimated sulfate improvements in $PM_{2.5}$ air quality presented here are only slightly above the U.S. EPA-recommended 24-hour significant level of 1.3 $\mu g/m^3$ as presented in the recent Draft Precursor Guidance and could actually be less than the significant level. This reduction would possibly be accompanied by other increases in fuel combustion emissions, production

[22] Federal Register, Volume 82, page 9043, February 2, 2017, Air Plan Approval; AK, Fairbanks North Star Borough; 2006 $PM_{2.5}$ Moderate Area Plan, Proposed Rule.

of a brown NOx cloud in the Chena plant stack, and elimination of the beneficial use of fly ash collected at the plant as fill material. These observations indicate that the environmental benefit of installing SO_2 controls at Chena Power Plant will produce no noticeable improvement in ambient $PM_{2.5}$ air quality and may produce negative associated environmental impacts.

3.4 ENERGY CONSIDERATIONS

Retrofit BACT as a means to reduce the pollutant load in an air basin must necessarily look at the effect that employing BACT on a specific source would have on other sources in the air basin and whether this effect would negatively impact the air quality improvement that is presumed to occur when BACT is employed. The original BACT Analysis presented a detailed discussion of energy considerations arises from the use of add-on air pollution control equipment. The reader is referred to that document for additional information regarding energy considerations for additional fuel and electricity consumption.

3.5 SUMMARY OF ENVIRONMENTAL AND ENERGY CONSIDERATIONS

The environmental considerations associated with installation of SO_2 controls on the Chena Power Plant produce uncertain assurances that any improvement in FNSB air quality will result. In fact, the data suggest that insignificant environmental improvements at best could occur. The energy considerations point to a likely lack of an air quality benefit in FNSB in the event that SO_2 controls are implemented at Chena Power Plant. In fact, such implementation could actually increase the air pollutant load in FNSB from sources more likely to produce a $PM_{2.5}$ ambient impact than Chena Power Plant.

4 ANALYSIS OF ASPECTS RELATED TO BACT

The supplemental information presented herein supports and enhances the SO_2 BACT determination presented in the original BACT Analysis. The previous sections of this supplement analyzed the several aspects that must be considered in a BACT determination, those being technical feasibility, economics, environment, and energy. This analysis yielded the following findings:

1. The technical feasibility of employing add-on SO_2 controls at Chena is highly questionable due to lack of available space at the facility for the equipment needed to scrub the flue gas as well as raw material receiving and processing equipment. Furthermore, the degree of control afforded by SDA and DSI technology is highly variable and difficult to define for conditions existing at Chena.

2. The economic analysis shows that use of SDA or DSI technology for SO_2 control is does not make economic sense as a retrofit option at Chena Power Plant.

3. The environmental considerations demonstrated that no significant ambient $PM_{2.5}$ improvement would be obtained by requiring SO_2 controls on Chena Power Plant. ADEC also recognizes that controlling direct $PM_{2.5}$ emissions (such as from wood stoves) is 13 times more effective at reducing ambient $PM_{2.5}$ concentrations than controlling precursor air pollutants that produce secondary $PM_{2.5}$. Furthermore, the actual ambient $PM_{2.5}$ benefit that can be achieved by reducing SO_2 emissions is extremely uncertain and difficult to calculate.

4. From an energy standpoint, installing an add-on SO_2 control device would increase the parasitic load at the Chena Power Plant. Loss of this energy output would require supplemental energy consumption at other sources within the FNSB or acquired through the grid from Anchorage to compensate for this parasitic load. This supplemental energy consumption at other sources may actually produce an increase in direct $PM_{2.5}$ emissions if the lost capacity were to be offset by fuel consumption for sources such as wood-burning stoves or oil-fired boilers, which tend to emit more direct $PM_{2.5}$ than Chena Power Plant, and at lower elevations. Furthermore, ADEC has already concluded, based on CMB

evaluations of PM filters in the FNSB, that these lower level sources are the more significant contributors to ambient $PM_{2.5}$ concentrations. Thus, the energy impacts of requiring SO_2 controls on Chena Power Plant could potentially have the exact opposite effect as desired and produce increases in ambient $PM_{2.5}$ concentrations in the FNSB.

4.1 DETERMINATION OF BACT FOR SO_2

Alaska coal has very low sulfur content, and uncontrolled sulfur emissions are four times lower than at a plant burning "low sulfur coal" in the lower 48 states.[23] The result is that the cost-effectiveness of SO_2 control technologies is poorer in Alaska than the lower 48 states. Current SO_2 emission rates from the Chena Power Plant are comparable to those identified as BACT in the most recent BACT determinations included in the RBLC database.

Therefore, as concluded in the original BACT Analysis, BACT for SO_2 emissions from Chena Power Plant is determined to be the continued use of low-sulfur coal.

[23] ADEC, Amendments to: State Air Quality Control Plan SIP, Vol. III: Appendix III.D.5.7, Appendix to Volume II. Analysis of Problems, Control Actions; Section III. Area-wide Pollutant Control Program; D. Particulate Matter; 5. Fairbanks North Star Borough $PM_{2.5}$ Control Plan, December 24, 2014, page III.D.5.7-78.

THE STATE of ALASKA
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September 13, 2018

David Fish, Environmental Manager
Aurora Energy, LLC
100 Cushman St., Ste. 210
Fairbanks, AK 99701

Subject: Second request for additional information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant by November 1, 2018

Dear Mr. Fish:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the Aurora Chena Power Plant and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to Serious Non-Attainment Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measures (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the Aurora Chena Power Plant. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Mr. Fish at Aurora on May 11, 2017 notifying him of the reclassification to Serious and

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

included a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis from Aurora, which included emission units found in Operating Permits AQ0315TVP03 Revision 1, was submitted by email to the Department on March 20, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the Chena Power Plant for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from Aurora to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that Aurora review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for Aurora, it must include the determination in Alaska's Serious SIP which ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

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

Sincerely,

BY DIR

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for Chena Power Plant BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for Aurora Energy LLC, BACT Analysis
November 15, 2017	EPA Aurora Energy – Chena Power Plant BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for Aurora Energy, LLC

cc: Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/Air Quality
Jim Plosay, ADEC/Air Quality
Aaron Simpson, ADEC/Air Quality
David Fish/Aurora Energy, LLC
Tim Hamlin/EPA Region 10
Dan Brown/EPA Region 10
Zach Hedgpeth/EPA Region 10

ADEC Request for Additional Information
Aurora Energy LLC. – Chena Power Plant
BACT Analysis Review
Environmental Resources Management Report, March 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Alternative Fuel Source – Page 17 of the analysis indicates that it is assumed that use of another type of coal would not reduce NOx emissions, and use of an alternate fuel is considered technically infeasible, but did not include a substantive analysis. As indicated in the Approval and Promulgation of the State of Washington's Regional Haze State Implementation Plan[1], the use of SNCR and Flex Fuel[2] was selected as BART for the TransAlta coal-fired power plant. Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.
2. Low Excess Air (LEA) and Overfire Air (OFA) – Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NOx formation is inhibited because less oxygen is available in the combustion zone. Overfire air is the injection of air above the main combustion zone. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NOx by 10 to 20 percent from uncontrolled levels.[3] Evaluate these technically feasible control technologies using EPA's top down approach.
3. Additional SO_2 Control Technologies – The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO_2 removal, and therefore must be included in the analysis. Page 32 of the analysis indicates that the combined exhaust from the Chena Power Plant is currently controlled by a common baghouse and that installation of a dry injection or spray drying operation would require the existing baghouse be retrofit with a new PM control system to accommodate the much greater PM loading produced by a dry injection or spray dry system. It further states that the installation of such technologies would

[1] EPA–R10–OAR–2012–0078, FRL–9675–5

[2] Flex Fuel is the "switch from Centralia, Washington coal to coal from the Power River Basin in Wyoming. Powder River Basin coal has a higher heat content requiring less fuel for the same heat extraction, as well as a lower nitrogen and sulfur content than coal from Centralia. Flex Fuel also required changes to boiler design to accommodate Powder River Basin coal."

[3] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

be cost-prohibitive and therefore technically infeasible. However, the BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

The EPA cost manual does not currently include a chapter covering DSI. However, as part of their Regional Haze FIP for Texas, EPA Region 6 developed cost estimates for DSI as applied to a large number of coal fired utility boilers. See the Technical Support Documents for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) for additional information. The Cost TSD and associated spreadsheets are located at: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0008. Please update the cost analysis for these technologies and provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs). Provide in the analysis: the control efficiency associated with the technologies, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please see comments 5, 6, and 7 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

5. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

6. Baseline Emissions – Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and LNBs) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

7. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control

efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

8. Good Combustion Practices – For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.
9. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.
10. Provide an economic analysis for circulating dry scrubber (CDS) SO_2 technology for the coal fired boilers (EUs 1-6). Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual. Please provide technical justifications for all assumptions used in the analysis submitted as part of the BACT analysis (i.e., direct and indirect contingency costs, startup costs, initial performance test costs, electricity rate, and reagent costs).
11. Review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis. In this analysis use a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.
12. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The “date certain” removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
  - Measure R1, page 63: Natural gas fired kiln or regional kiln.
  - Measure R12, page 71: Replace uncertified stoves in rental units.
  - Measure R17, page 75: Ban use of wood stoves
  - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
  - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
  - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98th percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in "emission inventory" versus "emissions inventory".

Page 1: "CAA" to "Clean Air Act" for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1's calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the "winter season" inventory as the "seasonal" inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, "results in extremely high heating energy demand per square foot experienced in no other location in the lower-48."

Page 9: Please change "Violations" to "Exceedances." Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add "No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.", to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., "downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear "For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a "base" demand typically met by cleaner home heating oil when ambient temperatures get colder."

Page 19: Remove "Where appropriate,". All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove “com”

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add “threshold” after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change “has decided” to “decided.”

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding “… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value” to the sentence that starts “The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing “slightly” and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption “These restrictions shall not apply during a power failure.” should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for “Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, “did not know if the rule had worked well” needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists “none” under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

November 1, 2018

Alaska Department of Environmental Conservation
Division of Air Quality
ATTN: Director
410 Wiloughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: Second Request for Additional Information for the Best Available Control Technology Technical Memorandum from Aurora Energy, LLC (Aurora) for the Chena Power Plant.

Dear Ms. Koch,

Thank you for the opportunity to provide additional information to better characterize Aurora's operations for the Best Available Control Technology (BACT) Analysis which will be a part of the Serious Area State Implementation Plan.

The following is being provided in response to the information request letter dated September 13, 2018. The ADEC letter included an enclosure with twelve comments for which additional information was requested. Each comment is summarized below followed by a response from Aurora. The information is being submitted to the ADEC by November 1, 2018 as requested.

1. Alternative Fuel Source - Evaluate alternative coal sources as a potential control option for the coal-fired boilers and identify energy, environmental, and economic impacts and other costs that would affect the selection of an alternative source of coal as a technically feasible control option. Evaluate the control efficiency of alternative coal sources based on a comparison of the coal's heat content as well as nitrogen and sulfur content.

   Response: There are no other economically viable coal options for Aurora. Usibelli Coal Mine is the state's only operating coal mine.

2. Low Excess Air (LEA) and Overfire Air (OFA) - Evaluate these technically feasible control technologies using EPA's top down approach.

   Response: Aurora's BACT analysis dated March of 2017, Section 2.3.2, references the use of combustion controls, including OFA and LEA. The BACT analysis concludes that the Unit 5 (EU 7) is already equipped with OFA, LEA (i.e., oxygen trim system), and air preheaters. It is stated within the BACT that Units 1, 2, and 3 (EU 4-6) have OFA and air preheaters. Although the air preheater ductwork is installed, the preheaters have been removed from operation. The current

configuration of the traveling-grate boilers as installed, includes a 'partial' LEA (i.e., oxygen trim system). The fuel feed rate and oxygen for Boiler Units 1-3 (EU 4-6) are manually adjusted and tuned daily. The traveling-grate boilers have a knife gate which sets the bed thickness and the air-to-fuel ratio is manually adjusted to accommodate the boiler's performance. Once adjusted, the fuel-to-air ratio is maintained automatically.

3. Additional SO_2 Control Technologies - The BACT analysis does not include a substantive analysis of spray-dry scrubbing, dry flue gas desulfurization, dry scrubbing, or dry sorbent injection (DSI). All of these technologies have the potential to offer SO2 removal, and therefore must be included in the analysis.

   Response: - An addendum to the initial BACT submittal was provided to the State on December 22, 2017. This addendum included a substantive analysis of Spray Dry Absorbers (SDA) and Dry Sorbent Injection (DSI) technologies.

4. BACT Limits - Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

   Response: Statements concerning applicable standards under 40 CFR Parts 60 (New Source Performance Standards—NSPS) and 61 (National Emission Standards for Hazardous Air Pollutants—NESHAP) are not relevant to the Chena boilers. The NESHAP do not regulate criteria air pollutants such as SO_2, and therefore, no SO_2 floor can be defined by any NESHAP. Furthermore, the Chena boilers are not subject to NSPS and therefore are not required to achieve the NSPS standard. In any case, the NSPS SO_2 emission limit of 1.2 lb/MM Btu (for units less than 75 MM Btu/hr) is achieved in the small boilers (the percent reduction is not a requirement for units less than 75 MM Btu/hr).

   An NSPS or NESHAP standard must be considered as the floor for BACT only when a source is subject to one of the standards. In that case, a source must achieve compliance with the NSPS or NESHAP, and a less stringent emission limit cannot be considered BACT. As noted in a July 28, 1987 memo by Gary McCutchen, then Chief of the New Source Review Section of the US EPA:

   > "Since an *applicable* NSPS must always be met, it provides a legal "floor" for the BACT, which cannot be less stringent." (emphasis added). This statement implies that a source must first be subject to an NSPS for the standard to be considered the BACT floor.

   The Chena plant operates four coal-fired boilers: three at 76.8 MM Btu/hr (22.5 megawatt, MW) heat input and one at 254.7 MM Btu/hr (74.6 MW) heat input. If newly-constructed today, the three smaller units would be subject to an NSPS Subpart Dc limit of 1.2 lb SO_2/MM Btu, and the larger unit would be subject to an NSPS Subpart Da limit of 0.15 lb SO_2/MM Btu. On a Btu-weighted average basis, the overall NSPS limit would be 0.64 lb SO_2/MM Btu. The Chena boilers

currently combust low-sulfur coal, with emissions of 0.39 lb SO_2/MM Btu from the combined exhaust. This overall emission rate represents a 39% reduction from NSPS limits if the Chena boilers had been built today.

Regardless of the NSPS applicability to the Chena boilers, the history of rulemaking for small industrial, commercial, and institutional (ICI) boilers provides valuable insight into the definition of BACT for SO_2 from these units. The three smaller units, if constructed today, would be subject to NSPS Subpart Dc for small ICI boilers. As defined in the standard, ICI units smaller than 22 MW (75 MM Btu/hr) heat input are not subject to a percent reduction requirement in NSPS and instead may achieve compliance with NSPS through the use of low-sulfur fuel. The rationale for this "exemption" is provided in the preamble to the proposed rule (54 *Federal Register* (FR) 24806, June 9, 1989) and the Background Information Document for the Promulgated Standards. As discussed in the Background Document:

> "Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable....Imposing these high (capital and annualized) costs for the units (those less than 22 MW) was considered to be unreasonable when compared to the increase in emission reduction achievable be the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less."

The passage presented above is the basis for the US EPA's definition of BACT for small ICI boilers less than 22 MW. This analysis therefore defines BACT for such units as an emission rate equal to or greater than 1.2 lb SO_2/MM Btu. In the proposed rule, US EPA further states that compliance with this NSPS limit/ BACT emission rate for units smaller than 22 MW (75 MM Btu/hr) can be achieved through use of low-sulfur fuels (see 54 FR 24793). For all practical purposes, the three smaller boilers at the Chena plant fall into this category, and therefore BACT is defined as an emission limit of 1.2 lb SO_2/MM Btu, achieved through combustion of low-sulfur coal. Furthermore, as illustrated above, the four boilers at the Chena plant collectively operate with an actual SO_2 emission level that is 39 percent less than the levels that would be required if all of the units were subject to NSPS.

5. Retrofit Costs - Provide detailed cost analyses and justification for difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analysis.

   Response: The BACT cost analysis employed a retrofit factor of 2.0. The basis for this factor was the EPA Air Pollution Control Cost Manual, Sixth Edition. As discussed in the Cost Manual:

   > "To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the

> cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst....The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. Even at detailed cost level (± 5 percent accuracy), vendors will not be able to fully assess the uncertainty associated with a retrofit situation and will include a retrofit factor in their assessments." (see page 2-28 in EPA/452/B-02-001)

As noted in the above citation, US EPA notes that a retrofit factor can be as high as 1.5, this partially supports the value selected for the Chena BACT cost analysis. The cost model employed during the BACT analysis (i.e., CUECost) suggests the following retrofit factors: 1.0 factor for a new facility, a 1.3 factor for a moderately difficult retrofit, and a 1.6 factor for a difficult retrofit. The user is also given the option to input his own retrofit factor based on plant-specific information. As noted by the Northeast States for Coordinated Air Use Management (NESCAUM) in a in a report entitled "Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for industrial, Commercial, and Institutional (ICI) Boilers an independent researcher (Emmel) noted that:

> "this range (of CUECost retrofit factors) significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs (i.e., electric generating units) less than 100 MW. Emmel also noted that on average, a retrofit factor of 1.45 was more reasonable and that the factor should even be higher when CUECost is applied to ICI boilers."

Two main factors impact selection of the retrofit factor for the Chena plant: space availability and equipment congestion. These two factors will require additional efforts for installation, equipment staging, and maneuverability during construction.

6. Baseline Emissions - Include the baseline emissions for all emission units included in the analysis. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). The baseline is usually the legal limit that would exist, but for the BACT determination.

Response: The Baseline Emission rate is not a legal limit. As stated in the U.S. EPA 1990 New Source Review Workshop Manual:

> "Calculating Baseline Emissions"
>
> The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. *The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions.* In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. (emphasis added)"

Based on this guidance, the Chena baseline emissions were properly calculated and applied to the BACT analysis.

7. Factor of Safety - If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   Response: The current BACT analyses included operating as is, therefore a factor of safety was not included.

8. Good Combustion Practices - For each emission unit type (coal boilers, distillate boilers, engines, and material handling) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices.

   Response: Good combustion practices were not proposed. The operation of existing combustion controls (OFA & LEA) were determined to be BACT for NOx.

9. Interest Rate - All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

   Response: Suggest that the State revise interest rate to prime (currently 5.25%) and equipment life to 10 years, not 15, due to corresponding short remaining lifespan of associated boilers.

10. Economic Analysis for Circulating Dry Scrubber (CDS) - Provide in the analysis: the control efficiency associated with CDS, captured emissions (tons per year), emissions reduction (tons per year), capital costs (2017 dollars), operating costs (dollars per year), annualized costs (dollars per year), and cost effectiveness (dollars per ton) using EPA's cost manual.

    Response: See attached memo "CDS v SDA Cost Comparison.pdf" for CDS analysis.

11. Review State's Spreadsheets – Review cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010.

    Response: Aurora has provided a review of the ADEC's cost effectiveness spreadsheets and inputs. Comments are included on the spreadsheets. Please reference documents "chena-so2-economic-analyses-adec--With ERM Comments.xlsm" and "chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm".

12. Site-Specific Quotes Needed - The cost analyses, particularly for SO2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT.

Response: Included as attachments within this response are vendor quotes as well as a cost analysis for Dry Sorbent Injection (DSI). Due to time constraints, the consultant was able to provide a +50/-30 cost estimate. Please reference the enclosed documents, to include: "Aurora Energy Preliminary Opinion of Probable Cost.pdf"; "Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf"; "BACT Proposal No. 1899-R1.pdf"; and "Aurora_Chena_DSI_General Arrangement.pdf".

Below are a list of documents that are being provided as enclosures which are referenced within the responses given above. If there are any questions pertaining to the information provided, please contact David Fish at dfish@usibelli.com or 907-457-0230.

Sincerely,

David Fish
Environmental Manager

Enclosures:

1. CDS v SDA Cost Comparison.pdf
2. chena-so2-economic-analyses-adec--With ERM Comments.xlsm
3. chena-large-boiler-so2-economic-analyses-adec--With ERM Comments.xlsm
4. Aurora Energy Preliminary Opinion of Probable Cost.pdf
5. Aurora_DSI_Opinion_of_Probable_Cost_rev0.pdf
6. BACT Proposal No. 1899-R1.pdf
7. Aurora_Chena_DSI_General Arrangement.pdf
8. Unified Facilities Criteria (UFC) DoD Facilities Pricing Guide (ufc_3_701_01_c1_2018.pdf)
9. ufc_3_701_01_data_tables_may_2018.xlsx
10. NSPS ICI SO2 RE.docx
11. ICI Boilers 20081118 final_revised-Jan2009.pdf
12. EPA Air Pollution Cost Control Manual, sixth edition, January 2002, accessible at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf.

Cc:
Larry Hartig, ADEC/Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Denise Koch, ADEC/ Air Quality
Cindy Heil, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/ Air Quality
Buki Wright/ Aurora Energy, LLC
Rob Brown/ Usibelli Coal Mine, Inc.
Tim Hamlin/ EPA Region 10
Dan Brown/ EPA Region 10
Zach Hedgpeth/ EPA Region 10

STANLEYCONSULTANTS, Inc
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November 1, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Qualitative Cost Comparison of Circulating Dry Scrubber Technology Versus Spray Dryer Absorbers

David:

Per your request Jason Smith and I have developed a comparison between the Circulating Dry Scrubber and Spray Dry Absorption technologies and the expected differences in total installed cost. Jason is an expert in SO_2 scrubbers having participated in the construction, startup, and commissioning of several installations over the course of his career.

The two commercially available semi-dry acid gas scrubbing processes consist of Spray Dryer Absorption (SDA) and Circulating Dry Scrubber (CDS). Both technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with sulfur dioxide (SO2) and sulfur trioxide (SO3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash is 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 process also depend on the humidification of the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduced 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 humidification of the flue gas stream 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 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 pumped, the SDA process can sometimes leverage existing infrastructure such as existing particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system serves to limit 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, just to name a few.

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 typically occurs after a venturi assembly that increases the velocity of the passing gas stream to establish a fluidized bed of alkaline material. The flue gas then passes through this bed and 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 collector be placed at higher elevations. This will ensure that the proper slope is maintained between the collector and the injection point on the absorber tower. It is technically challenging to take an existing 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 to accommodate the higher elevation construct to be handled under a single contract, thus limiting risk for the owner. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the necessary capital outlay for the 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 does not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in a significantly larger installation cost when compared to an equivalent SDA system. Given that the ADEC Preliminary BACT Determination for the Chena Plant (Dated March 22, 2018) has already established that a SDA system is not economically feasible (Table 4-3, Page 12), it can therefore be concluded that the CDS system is economically infeasible as well.

Please let me know if you have any questions or comments regarding the information presented in this letter.

Sincerely,

John P Solan

John P. Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

STANLEYCONSULTANTS, Inc

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October 30, 2018

David Fish
Environmental Manager
Aurora Energy, LLC
100 Cushman St.
Suite 210
Fairbanks, AK 99701-4674

RE: Preliminary Opinion of Probable Cost for Addition of Dry Sorbent Injection

David,

This letter serves to document the preliminary results of our opinion of probable cost for the installation of a Dry Sorbent Injection (DSI) System at the Aurora Energy Chena Plant for the control of Sulfur Dioxide (SO_2) emissions.

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 report to the Alaska Department of Environmental Conservation (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 report, ADEC conducted their own analysis and presented their results as a Preliminary BACT Determination in March of 2018. The results developed by ADEC as a part of their analysis were significantly different from the results presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy has hired Stanley Consultants to develop a site-specific, third-party estimate of the costs to install SO_2 emissions control equipment on the four operating boilers at the Chena Combined Heat and Power Plant near downtown Fairbanks. Stanley Consultants will also provide an estimated sorbent consumption rate and a cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, ERM, will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a Dollars/Tons of SO_2 removed basis.

This letter serves to document the preliminary Opinion of Probable Cost results so that Aurora Energy can submit a response to the BACT Determination ahead of a November 1, 2018 deadline. The information included herein relates only to the installation of a DSI system on the existing boilers. All performance information, quantities, and costs are preliminary and are

subject to revision as the cost estimate is refined and finalized. Additional clarifications as to the basis of the cost estimate and the anticipated performance are included below.

Design Basis

Boiler Performance and Flue Gas

Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates from the previous reports were utilized to determine equipment sizes and required sorbent feed rates

Dry Sorbent Unloading, Storage, Preparation, and Injection System

Equipment and piping costs for the Dry Sorbent Injection 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 the emissions from burning Healy coal in stoker-type boilers. The BACT proposal includes:

- 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 is sufficient for four 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.
- 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 equipment or systems that are required for proper operation of the DSI system, but was not included in the BACT proposal have been included separately in the cost estimate. This includes:

- Piping between the sorbent preparation building and the injection lance on each flue
- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse
- Electrical feeds and equipment required to support the BACT equipment
- 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 – Adjacent to the unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment – Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building – Adjacent to the existing baghouse

See the attached sketch for additional information on the proposed equipment locations and interconnecting piping.

Opinion of Probable Cost

Based on the information above, the current estimate of probable cost is as follows:

Total Installed Cost: $20.682MM

Sorbent Cost: $550/Ton, Delivered

Reference the attached spreadsheet for additional information relating to the equipment and construction costs used. Total installed costs include probable costs for engineering, procurement and construction of the DSI system. It also includes mobilization and indirect contractor costs such as bonding, overhead, and profit. Finally, the Total Installed Cost includes an escalation factor to account for inflation and other cost increases over the construction period.

Clarifications

- The estimated accuracy of this Opinion of Probable Costs is +50% and -30%. The accuracy is expected to improve as the cost estimate is refined.
- 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 degrees 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 degrees 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 costs included in this estimate are based on the best information that we have been able to obtain to-date. The refinement of existing costs or the inclusion of additional direct or indirect costs may be determined to be necessary as the preliminary design develops.
- Sorbent pricing information provided by BACT in their equipment proposal was supplied by the sorbent vendor based on a proposal 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 we have available today.

Conclusion

The preliminary Opinion of Probable Cost presented in this letter is our current best estimate for the costs associated with the procurement and installation of a DSI system at the Chena Combined Heat and Power Plant. The estimate attempts to account for many of the site-specific factors that may negatively impact the actual capital costs including, plant configuration, site layout, seismic considerations, existing infrastructure, and local construction cost factors.

We hope the information presented in this letter meets your immediate needs and we look forward to providing you with a final Opinion of Probable Costs along with supporting documentation in the near future.

Thank you for the opportunity to assist Aurora Energy in this matter.

Sincerely,

John Solan
Senior Mechanical Engineer
Stanley Consultants, Inc.

cc: File

Attachments: DSI Equipment Layout Sketch

Opinion of Probable Cost Tabulation

Stanley Consultants INC.

		Rev. 0	Job No.	28709.01.00	Page No. 1
			Subject	Aurora Energy Chena - Dry Sorbent Injection	
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 10/29/2018		Opinion of Probable Cost	
Checked by	J. Solan	Date 10/29/2018			
Approved by	C. Spooner	Date 10/30/2018	Sheet No.	1 of 1	

Item	Item Description	Quantity No. of Unit	Quantity UOM	Unit Cost	Total Cost
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,880,200.00	$1,880,200
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	$6,370,000.00	$6,370,000
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	$238.00	$71,400
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$239.00	$74,090
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$239.00	$66,920
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$239.00	$47,800
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	$14,169,111
				Mobilization & Demobilization - 5%	$708,456
				Bond - 2.5%	$354,228
				Contractor Overhead - 10%	$1,416,911
				Contractor Profit - 10%	$1,416,911
				Total Construction Cost	$18,065,617
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$736,199
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,802,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,682,000**

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.

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 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

BEST AVAILABLE CONTROL TECHNOLOGY

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
Sorbent Prep Enclosure
Unit 5 Injection
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
Google Earth
© 2018 Google
300 ft

UFC 3-701-01
23 May 2018
Change 1, 25 June 2018

UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

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UNIFIED FACILITIES CRITERIA (UFC)

DoD FACILITIES PRICING GUIDE

Indicate the preparing activity beside the Service responsible for preparing the document.

U.S. ARMY CORPS OF ENGINEERS

NAVAL FACILITIES ENGINEERING COMMAND (Preparing Activity)

AIR FORCE CIVIL ENGINEER CENTER

Record of Changes (changes are indicated by **\1** ... **/1/**)

Change No.	**Date**	**Location**
1	6-25-18	Update Table 3 with RUC. Text update 3-2.

This UFC supersedes UFC 3-701-01, dated March 2011.

FOREWORD

The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with USD (AT&L) Memorandum dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of Forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the most stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Center (AFCEC) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: Criteria Change Request. The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site http://dod.wbdg.org/.

Refer to UFC 1-200-01, *DoD Building Code (General Building Requirements)*, for implementation of new issuances on projects.

AUTHORIZED BY:

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UNIFIED FACILITIES CRITERIA (UFC)
[REVISION] SUMMARY SHEET

Document: UFC 3-701-01, *DoD Facilities Pricing Guide*

Superseding: UFC 3-701-01, dated March 2011

Description: The document provides updated cost and pricing data in support of facility planning, investment and analysis needs.

Reasons for Document:

- This UFC provides updated cost and pricing data intended to support preparation of the DoD budget.

Impact:

- Provides consistency across the DoD for the development of budgets for military construction projects.

Unification Issues

None

TABLE OF CONTENTS

CHAPTER 1 INTRODUCTION

1-1 PURPOSE AND SCOPE.

The DoD Facilities Pricing Guide supports a spectrum of facility planning, investment, and analysis needs. This version of the Guide reflects updated cost and pricing data for FY 2018 intended to support preparation of the DoD budget for FY 2020. It includes reference information organized into three chapters, as follows:

1-1.1 Chapter 2: Unit Costs for Military Construction Projects.

Chapter 2 describes the usage of facility unit cost data for selected DoD facility types in support of preparing Military Construction (MILCON) project documentation (DD Forms 1391) and other program-level estimates in accordance with UFC 3-730-01, "Programming Cost Estimates for Military Construction."

1-1.2 Chapter 3: Unit Costs for DoD Facilities Cost Models.

Chapter 3 describes the usage of unit costs in support of DoD facilities cost models. These unit costs are based upon the reported average DoD facility size or an established benchmark size, as annotated for each Facility Analysis Category (FAC) in the DoD Real Property Classification System (published separately). These unit costs are intended for macro-level analysis and planning rather than individual facilities or projects.

1-1.3 Chapter 4: Cost Adjustment Factors.

Chapter 4 describes the usage of cost adjustment factors for location and price escalation that are applicable to the base unit costs in both Chapters 2 and 3.

1-2 APPLICABILITY.

This UFC applies to all projects in both the continental US (CONUS) and outside the continental US (OCONUS).

1-3 DATA TABLES.

All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

1-4 PROPONENT.

The Office of the Assistant Secretary of Defense for Energy, Installations, and Environment is the proponent for the Facilities Pricing Guide. Recommendations from users toward improving the usefulness of this reference are welcome.

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CHAPTER 2 UNIT COSTS FOR MILITARY CONSTRUCTION PROJECTS

2-1 OVERVIEW.

The facility unit costs in this chapter apply to preparation of programming-level cost estimates for constructing military facilities in accordance with the methodology described in UFC 3-730-01.

All data tables in this UFC are found under “Related Materials” in a combined file accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

2-2 FACILITY UNIT COST TABLE.

Table 2 provides facility unit costs for various DoD facility types in dollars per square meter ($/SM) and equivalent English unit cost data in dollars per square foot ($/SF) as of October 2017. The listed facility types represent only those facilities most frequently constructed by the Military Services, and the application of a facility unit cost may not be directly applicable for those facilities with unique requirements. See UFC 3-730-01 for additional guidance on facility unit costs and their application.

The unit costs in Table 2 are average unit costs for new construction based on no less than three project awards per building type occurring since September 2014 for Army, Navy, Air Force, Defense Education Activities (for school projects) and Defense Health Agency (for medical projects) facilities as entered into the Historical Analysis Generator (HII) unit cost database prior to 1 Nov 2017. Facility additions which are less than 25% of the Reference Size of the listed facility type, and projects outside of the continental United States (OCONUS), are included only for Family Housing and DoD Schools. For additional information regarding how the facility unit costs are determined, refer to paragraph 2-3, Guidance Unit Cost Development.

2-3 GUIDANCE UNIT COST (GUC) DEVELOPMENT METHODOLOGY.

2-3.1 Data Source.

The data source for the facility unit costs is all reliable HII project records, after excluding records for reasons stated in paragraph 2-2. In general, all project records for the CONUS and projects from Alaska and Hawaii are included.

Facility level information from all three Services projects is entered into HII database for comparable service category codes (CATCODEs). Normalized project unit costs are statistically analyzed to eliminate outliers before calculating the guidance unit cost (GUC).

2-3.2 Business Rules.

The business rules are reviewed annually prior to updating Table 2 Facility Unit Costs for Military Construction. The business rules include the following components.

- The Tri-Service CATCODEs Cross-walk table groups like service CATCODEs to a common Office of the Secretary of Defense (OSD) Code. OSD Codes are not published and are only utilized for this task of segregating data. A minimum of three projects are required within those defined years to create a dataset. If there is insufficient data available within the above three-year period, the dataset search is extended to the last four years.
- Projects are new construction only.
- Projects are located within the CONUS, plus Hawaii and Alaska, except where noted otherwise in Table 2.
- Projects with extreme variation from the mean (50%) are excluded., and
- Exclusion of inappropriate data for cause.

2-3.3 Data Normalization.

Each facility-specific data set is normalized to the National Average Area Cost Factor (ACF=1) and number of bidders, and escalated to October of the year of interest, before unit costs are averaged.

- Escalation: The DoD Selling Price Index (DoD-SPI), which is an average of three commonly accepted national construction price escalation indices, is utilized to escalate actual project award cost data to October of 2017 for this UFC,
- Number of Bidders: Based on actual bid data for the data set,
- Location: Normalize each project award by the appropriate ACF to the national average of 1.0, and
- Facility Size: Normalize each facility award amount in the dataset for facility size, using a normalization process that looks at the facility size as compared to the average facility size of the selected dataset by OSD code.

2-3.4 Primary Facility Included Costs.

The facility unit costs include the following:

- Minimum antiterrorism design features (reference UFC 4-010-01, “DoD Minimum Antiterrorism Standards for Buildings”) inside the building meeting Table B-1 standoff distance requirements,
- Sales tax on building materials,

- Building information system costs (e.g., conduits, racks, trays, telecommunication rooms) without any specialized communications requirements,
- Installed (built-in) building equipment and furnishings normally funded with MILCON funds,
- Energy Management Control System (EMCS) connections,
- Intrusion Detection System (IDS) infrastructure, including conduits, racks, and trays,
- Sustainable design and construction features - energy consumption reduction requirements mandated before 6 November 2016; and all other sustainable design features for criteria in effect from September 2014 thru September 2017 with the exception of renewable energy generation elements,
- Progressive Collapse premiums for the following specific facility types: Inpatient Hospital/Medical Center, Primary Care Clinic (Attached), Major Command Headquarters Building, Barracks/Dormitory, and Recruit Open Bay (Barracks), and
- Standard foundation systems (e.g. strip/spread footings, thickened edge slab for slab on grade).

2-3.5 Primary Facility Excluded Costs.

The unit costs do not include the following:

- Gross receipt taxes or gross taxes, gross excise taxes, or state commerce taxes,
- “Acts of God” or unusual market conditions,
- Supporting facility costs,
- Equipment acquired with other fund sources, including pre-wired workstations or furnishing systems, intrusion detection systems,
- Sustainable design and construction features - renewable energy generation elements; energy consumption reduction requirements mandated on or after 6 November 2016; and all other features mandated since September 2017; these will be estimated separately in accordance with component guidelines and documented on DD Form 1391 per DoD Instruction 4170.11, Installation Energy Management,
- Special foundations (e.g. pre-stressed concrete piles, caissons), intrusion detection system installation, base exterior architectural preservation guidelines,

- Enhanced Anti-Terrorism (AT) standards (exceeding the minimum in UFC 4-010-01, or when minimum standoff distances [Table B-1] are not achieved) construction contingency allowances,
- Cybersecurity costs,
- Supervision, inspection, and overhead (SIOH),
- Design costs (design-build contracts), and Construction cost growth resulting from user changes, unforeseen site conditions, or contract document errors and omissions.

2-3.6 Primary Facility Cost Considerations.

The following are cost considerations for primary facilities:

- Medical facilities: Unit costs include category A and category B equipment and building infrastructure for category C equipment,
- Housing for Unaccompanied Military Personnel: Unit costs for barracks, dormitories, and Unaccompanied Officers Quarters do not include free-standing kitchen equipment. In addition to using the size adjustment factors, use the project size adjustment factors in UFC 3-730-01,
- Child Development Centers: Unit costs do not include free-standing food service equipment or playground area and equipment,
- Family housing: Unit costs are based upon gross area and include sprinkler systems or fire-rated construction. Unit costs include post-award design costs,
- Reserve facilities other than reserve centers: Use the unit cost of the appropriate facility type, and
- Costs are independent of the acquisition strategy and are not specific to any single construction type.

CHAPTER 3 UNIT COSTS FOR DOD FACILITIES COST MODELS

3-1 OVERVIEW.

This chapter describes the unit costs and related factors used in support of DoD facilities cost models. These unit costs are intended for macro-level analysis and planning and are not reliable for individual facilities or project estimates.

Unit costs and related factors are associated with FACs represented by a 4-digit code in the DoD Real Property Classification System (RPCS), which is a hierarchical scheme of real property types and functions that serves as the framework for identifying, categorizing, and modeling the DoD's inventory of land and facilities. FACs are common across the department and suitable for department-wide applications. For each FAC, Table 3 identifies the associated unit cost to be used in DoD facilities cost models and metrics.

Whenever possible, unit costs and factors have been based upon approved government or commercial benchmarks. Detailed supporting data for unit costs is available, and accompanies this UFC on the WBDG Web site. All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-2 REPLACEMENT UNIT COSTS (RUC).

3-2.1 \1\ Definition and Use of Replacement Unit Costs. /1/

\1\ Replacement unit costs form the basis of calculating Plant Replacement Value (PRV) in a consistent manner across DoD, representing a complete and useable facility built to current DoD design standards. Replacement unit costs can also support large-scale program-level estimates for re-stationing plans with the addition of allowance for site preparation, earthwork, landscaping, and related factors. Replacement unit costs should not be used for individual project estimates. /1/

Replacement \1\ unit /1/ costs include construction of standard foundations, all interior and exterior walls and doors, the roof, utilities out to the 5-foot line, all built-in plumbing and lighting fixtures, security and fire protection systems, electrical distribution, wall and floor coverings, heating and air conditioning systems, and elevators. Replacement \1\ unit /1/ costs do not include project costs such as design, supporting facility costs, special foundations, equipment acquired with other funding sources (e.g. mission-funded components), contingency costs, or supervision, inspection, and overhead (SIOH). \1\ unit /1/ costs also do not include items that are generally considered personal property such as computer systems, and furniture. See paragraph 3-5, Revising Unit Costs, for guidance on requesting changes \1\ to replacement unit costs /1/in Table 3.

3-2.2 \1\ Plant Replacement Value (PRV). /1/

DoDI 4165.14 defines PRV as the cost to design and construct a notional facility to current standards to replace an existing facility on the same site. The factor values are provided in the “Report of the Plant Replacement Value (PRV) Panel, August 2001-May 2003” published by the Office of the Deputy Under Secretary of Defense (Installations and Environment). The standard DoD formula for calculating PRV is:

Equation 3-2 Calculating PRV

PRV = Q x RUC x ACF x HF x PD x SIOH x CF

Where:

PRV is plant replacement value

Q is facility quantity, in the same unit of measure as the RUC

RUC is replacement unit cost found in Table 3 of this UFC

ACF is area cost factor found in Table 4 of this UFC, to account for geographical differences in the costs of labor, materials and equipment

HF is an adjustment of 1.05 to account for increased costs for replacement of historical facilities or for construction in a historic district. The factor is 1.0, should the facility not qualify as “historical”.

PD is a factor to account for the planning and design of a facility; the current value of this factor is 1.09 for all but medical facilities, and 1.13 for medical facilities.

SIOH is the factor to account for the supervision, inspection, and overhead activities associated with the management of a construction project. The current value of the factor is 1.057 for facilities in the (CONUS), and 1.065 (USACE) or 1.062 (NAVFAC) for facilities in the (OCONUS).

CF is a factor of 1.05 to account for construction contingencies

3-3 SUSTAINMENT UNIT COSTS (SUC).

3-3.1 Definition.

Sustainment provides for maintenance and repair activities necessary to keep a typical inventory of facilities in good working order over its expected service life. It includes the following:

- Regularly scheduled adjustments and inspections, including maintenance inspections (e.g., fire sprinkler heads, HVAC systems) and regulatory inspections (e.g., elevators, bridges),
- Preventive maintenance tasks,
- Emergency response and service calls for minor repairs, and
- Major repair or replacement of facility components (usually accomplished by contract) that are expected to occur periodically throughout the facility service life.

Sustainment includes regular roof replacement, refinishing wall surfaces, repairing and replacing electrical, heating, and cooling systems, replacing tile and carpeting and similar types of work as well as overhead costs which include architectural and engineering services. It does not include repairing or replacing non-attached equipment or furniture, or building components that typically last more than 50 years (such as foundations and structural members). Sustainment does not include restoration, modernization, environmental compliance, facility leases, specialized historical preservation, general facility condition inspections and assessments, planning and design (other than shop drawings), or costs related to Acts of God, which are funded elsewhere. Other tasks associated with facilities operations (such as custodial services, grass cutting, landscaping, waste disposal, and the provision of central utilities) are also not included.

3-3.2 Use of Sustainment Unit Costs.

Sustainment unit costs represent the annual average sustainment cost for each FAC, and serve as the basis for calculating annual facilities sustainment requirements for DoD using the following formula:

Equation 3-3 Calculating Sustainment Requirement

$$SR = Q \times SUC \times SACF \times I$$

Where:

SR is sustainment requirement

Q is facility quantity, in the same unit of measure as the SUC

SUC is sustainment unit cost found in Table 3

SACF is sustainment area cost factor found in Table 4

I is the value(s) representing future-year escalation for operation and maintenance accounts, published in Table 4-4.

The Sustainment Requirement for each qualifying asset in the DoD inventory is aggregated by sustaining organization and sustainment fund type in the Facilities Sustainment Model (FSM), published annually.

3-4 UNIT COST SOURCES.

Unit costs for DoD cost models are developed using a variety of sources. These sources fall into the three categories described below, listed in order of preference of use. The source description and source group for each unit cost are identified in Table 3. Supporting documentation for each unit cost calculation is available in the "Supporting documentation" file download accompanying this UFC document on the WBDG website: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

3-4.1 Source 1 Published Data

Standard, easily-accessible published data that is highly applicable to the FAC. Source 1 is the most desirable due to ease of access, general applicability, and lack of bias. Examples include the DoD Tri-Service Committee on Cost Engineering, Service-specific cost guidance (USACE), commercial cost-estimating guidelines or models, or other Government-published cost guidance from federal, state, or local government agencies (e.g. Fairfax County (Virginia) Park Authority). Non-DoD source 1 data may require refinement for application in DoD, but is still considered source 1 if it closely matches the design attributes of the FAC.

3-4.2 Source 2 Similar Data

Data that is applied to facilities with similar but not identical characteristics (e.g., sewage waste treatment facilities and industrial waste treatment facilities). Source 2 also includes unpublished government or trade association cost data, and Component-validated costs for non-standard facilities that have no commercial counterparts (e.g. missile launch facilities or military ranges).

3-4.3 Source 3 Derived Data

Unpublished project-specific data derived from Component project documents (e.g. DD Forms 1391) or from calculating costs from reported Plant Replacement Value and inventory, or derived from using a ratio of sustainment to construction from a similar source 1 Facilities Analysis Category (e.g. FAC 2115, Aircraft Maintenance Hangar, Depot derived from FAC 2111, Aircraft Maintenance Hangar).

3-5 REVISING UNIT COSTS.

Users of this UFC are encouraged to suggest revisions to the published cost factors, particularly for facilities unique to their mission. Submit proposed changes to the proponent office in accordance with the following guidelines:

- Revised costs should come from an equivalent or superior source,
- Revised costs should be easily audited,
- Revised costs should be consistent with the functional definitions,
- Revised costs should be consistent with the FAC scope and
- Revised costs should be suitable for application throughout DoD.

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CHAPTER 4 COST ADJUSTMENT FACTORS

4-1 LOCATION ADJUSTMENTS.

Table 4-1 provides area cost factors (ACFs) to be used for adjusting "bare" unit costs to location-specific costs for the most common locations.

All data tables in this UFC are found in a combined file under "Related Materials" accompanying this UFC on the (WBDG) Web site: https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01.

4-1.1 Application

For military construction projects, use the MILCON ACFs with the primary facility unit costs from Chapter 2 or approved Air Force, Army, or Navy MILCON Pricing Guide. For calculating Plant Replacement Value, use the MILCON ACFs with the appropriate RUCs from Chapter 3. For calculating sustainment costs, use the sustainment ACFs with the appropriate SUCs from Chapter 3.

Do not use the MILCON ACFs to modify parametric cost estimates, detailed quantity-take-offs, unit price book (UPB) line items, commercial cost data, or user-generated unit costs. These cost estimating methods and databases have their own processes and factors for adjusting costs to different locations. MILCON ACFs or any component(s) that make up MILCON ACFs are only applicable to construction costs and should not be applied or utilized for any other purpose.

4-1.2 Data Source

In general, the Tri-Service Cost Engineering ACF software program evaluates the local costs for a United States market basket of eight labor crafts, 18 construction materials, and four equipment items. These labor, materials, and equipment (LME) items are representative of the types of products, services, and methods used to construct most military facilities in the United States. Each of the LME costs is normalized and weighted to represent its contribution to the total cost of a typical facility. The normalized LME is then modified by seven matrix factors that cover local conditions affecting construction costs. These matrix factors include weather, seismic, climatic (frost zone, wind loads, and HVAC systems), labor availability, contractor overhead and profit, logistics, and labor productivity and are relative to the U.S. standard. The resultant ACF for each location is normalized again by dividing by the 96-Base-City average to provide a final ACF that reflects the relative relationship of construction costs between that location and the 96-Base-City average as 1.00.

MILCON ACFs are calculated using a LME ratio of 35/63/2. Sustainment ACFs are calculated using a LME ratio of 53/46/1.

4-1.3 Survey

Both CONUS and OCONUS construction market surveys were conducted in 2017. The CONUS survey covered 300 locations that included 96 Base Cities (two per state in the continental U.S.). The OCONUS survey included 75 locations, and was based on a market basket of goods for typical U.S. labor, material, equipment, and construction methods.

CONUS and OCONUS surveys are performed annually. When local materials and construction methods differ from those represented by the published ACF, specific adjustments may need to be added to the project estimate to account for any differences. There is no easy correlation between the current MILCON ACFs and previous MILCON ACFs for specific locations. No common benchmarks exist because both the Base City average and the relationships between cities change with each survey. It is possible, however, to compare differences between several locations in this database with differences between the same locations in previous databases.

4-1.4 Force Majeure

The ACF is not intended to, or capable of, responding to rapid changes in the market place. Examples include Acts of God, accelerated construction schedules, changes in the demand and supply for construction materials, labor, and equipment. An increased demand for labor beyond what the local market can supply may require the enticement of premium pay, overtime hours, temporary living expenses, and travel expenses.

4-1.5 User Requested Revisions

Users may request revisions to published ACFs when market conditions unexpectedly change. Each request must be initiated by the USACE District senior cost engineer through HQUSACE or by the NAVFAC regional cost engineer to their corresponding NAVFAC Atlantic or Pacific Tri-Service Cost Engineering committee member. The local cost engineer shall provide updated market basket ACF software input factors with adequate backup documentation to HQUSACE or NAVFAC for them to update the Tri-Service Cost Engineering ACF software.

4-2 ESCALATION.

Tables 4-2, 4-3, and 4-4 provide escalation (inflation) factors used to adjust unit costs in Tables 2 and 3 (expressed in base-year dollars) to the desired year, as follows:

4-2.1 Military Construction.

Military construction project estimates that use unit costs from Table 2 should use the military construction escalation factor from table 4-2 for the expected midpoint of construction as described in UFC 3-730-01.

4-2.2 Plant Replacement Value Escalation Rates.

Plant Replacement Value (PRV) calculations that use replacement unit costs from Table 3 should use the escalation factor from Table 4-3 for the desired program year.

4-2.3 Facilities Sustainment.

Modeled facilities sustainment cost estimates that use unit costs from Table 3 should use the O&M escalation factor from Table 4-4 for the desired program year.

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APPENDIX A REFERENCES

UNIFIED FACILITIES CRITERIA

http://www.wbdg.org/ccb/browse_cat.php?o=29&c=4

UFC 3-730-01, *Programming Cost Estimates for Military Construction*

PLANT REPLACEMENT VALUE

https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc/ufc-3-701-01

Report of the Plant Replacement Value (PRV) Panel, August 2001 – May 2003, R&K Engineering, Inc. for the Office of the Deputy Under Secretary of Defense (Installations and Environment)

United States Environmental Protection Agency
Office of Air Quality Planning and Standards Research Triangle Park NC 27711
EPA-450/3-90-016 August 1990
Air

EPA

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

EPA-450/3-90-016

Small Industrial-Commercial-Institutional Steam Generating Units -- Background Information for Promulgated Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1990

2.3.3 Percent Reduction Standard

1. Comment: Two commenters (IV-D-08, IV-D-28) requested that the 90 percent SO_2 reduction requirement be eliminated and replaced with an emission limit of 520 ng/J (1.2 lb/million Btu) heat input. One commenter (IV-D-08) objected to applying the 90 percent SO_2 reduction requirement to all coal regardless of sulfur content. This commenter stated that the EPA's conclusion that no units will be built in the size range between 22 and 29 MW (75 and 100 million Btu/hr) heat input capacity and operating at greater than 55 percent capacity factor is flawed. This commenter stated that the SO_2 standard of 520 ng/J (1.2 lb/million Btu) heat input for coal-fired plants should apply to all steam generating units in this source category, regardless of size. This commenter further recommended that the full 90 percent SO_2 removal be required only when the 520 ng/J (1.2 lb/million Btu) limit could not be met by using low sulfur coals or by pretreating the coals.

Another commenter (IV-D-28) stated that the 90 percent SO_2 reduction requirement should be removed and that coal-fired steam generating units in the 8.7 to 29 MW (30 to 100 million Btu/hr) range should be required only to meet the 520 ng/J (1.2 lb/million Btu) SO_2 limit. The commenter stated that the percent reduction requirement would place an unjustified cost and performance burden on units in this range that either already meet or are close to meeting the 520 ng/J (1.2 lb/million Btu) SO_2 limit.

Response: Section 111 of the CAA requires standards to reflect application of the best demonstrated technology considering costs, nonair quality health and environmental impacts, and energy requirements. Section 111 also requires that for fossil fuel-fired steam generating units a percent reduction standard be established. Read together, this means that the

Administrator is compelled to include a percent reduction standard unless the impacts associated with the requirements would be unreasonable. As discussed in the background document, "Model Boiler Cost Analysis for Controlling Sulfur Dioxide (SO_2) Emissions from Small Steam Generating Units" (EPA-450/3-89-14), a small coal-fired steam generating unit of 22 MW (75 million Btu/hr) size and operating at a 55 percent capacity factor has an incremental cost-effectiveness value of about $3,600/Mg ($3,300/ton) relative to an emission limit standard of 520 ng/J (1.2 lb/million Btu). Capital and annualized costs are projected to increase by approximately 20 percent over the regulatory baseline for the percent reductions standard. However, these values increase significantly for units less than 22 MW (75 million Btu/hr) heat input capacity and for any unit less than 29 MW (100 million Btu/hr) operating at an annual capacity factor for coal of less than 55 percent. Imposing these high costs for these units was considered to be unreasonable when compared to the increase in emission reductions achievable by the percent reduction requirement on these units. Therefore, in keeping with the requirements of the CAA, the final standards will not require percent reduction for any units operating at less than a 55 percent annual capacity factor for coal or any unit with a heat input capacity of 22 MW (75 million Btu/hr) or less.

Finally, no conclusion was made that coal-fired steam generating units greater than 22 MW (75 million Btu/hr) heat input and greater than 55 percent capacity factor would not be built. Rather, this was a projection of sales over the next five years based on sales trends over the past several years. The sales projections for coal-fired units had no influence on the conclusion of the reasonableness of the percent reduction requirement. (The assumption was used in generating national impacts of the standards.) The model steam generating unit analysis examined the potential impacts of the percent reduction requirement on a coal-fired unit greater than 22 MW (75 million Btu/hr) and greater than 55 percent capacity factor. Therefore, should a unit be built, requiring 90 percent reduction of emissions would be reasonable.

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

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UNITS, SPECIES, ACRONYMS

Acronyms
APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
BOOS – Burners Out of Service
CAA – Clean Air Act
CAAA – Clean Air Act Amendments (of 1990)
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – Electrostatic Precipitators
FBC – Fluidized Bed Combustion
FF – Fabric Filter (also known as baghouse)
FGD – Flue Gas Desulfurization (also known as SO_2 scrubber)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
FSI – Furnace Sorbent Injection
GR – Gas Reburn
HHV – Higher Heating Value
ICI – Industrial, Commercial, and Institutional (boilers)
LAER – Lowest Achievable Emission Rate
LNB – Low-NOx Burner
LSDI – Lime Slurry Duct Injection
LSFO – Limestone Forced Oxidation
LSC – Low-Sulfur Coal (also known as compliance coal)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic-Northeast Visibility Union
MC – Mechanical Collector
NAAQS – National Ambient Air Quality Standard
NCG – Non-Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standards
NSR – Normalized Stoichiometric Ratio
OFA – Overfire Air
PC – Pulverized Coal
PRB – Powder River Basin (coal)
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SCA – Specific Collection Area
SCR – Selective Catalytic Reduction

SD – Spray Dryer
SIP – State Implementation Plan
SNCR – Selective Non-Catalytic Reduction
TCR – Total Capital Requirement
TR – Transformer Rectifier
UBC – Unburned Carbon
US EIA – United States Energy Information Administration
US EPA – United States Environmental Protection Agency
ULNB – Ultra Low-NOx Burner
VOM – Variable Operating and Maintenance (costs)
WESP – Wet Electrostatic Precipitator
WFGD – Wet Flue Gas Desulfurization (also known as wet SO_2 scrubber)

Chemical Species
HCl – Hydrochloric Acid
HF – Hydrofluoric Acid
H_2SO_4 – Sulfuric Acid
NOx – Oxides of Nitrogen (NO_2 and NO)
NO – Nitric Oxide
NO_2 – Nitrogen Dioxide
NH_3 – Ammonia
$PM_{2.5}$ – Particulate Matter up to 2.5 μm diameter in size
PM_{10} – Particulate Matter up to 10 μm diameter in size
S – Sulfur
SO_2 – Sulfur Dioxide
SO_4 – Sulfate
VOC – Volatile Organic Compound

Units
Length
m – meter
μm – micrometer or micron (0.000001 m; 10^{-6} m)
km – kilometer (1000 m; 10^3 m)
Mm – Megameter (1,000,000 m; 10^6 m)

Flow Rate
acfm – actual cubic feet per minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 g; 10^{-6} g)

kg – kilograms (1000 g; 10^3 g)

Force
psi – pounds per square inch

Power
W – watt (Joules/sec)
kW – kilowatt (1000 W; 10^3 W)
MW – megawatt (1,000,000 W; 10^6 W)

Energy
Btu – British thermal unit (= 1055 Joules)
MMBtu – million Btu
MWhr – megawatt-hour
kWhr – kilowatt-hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

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Andrew Bodnarik, New Hampshire Department of Environmental Services

Sunila Agrawal, New Jersey Department of Environmental Protection

NESCAUM is an association of the eight northeast state air pollution control programs and provides technical guidance and policy advice to its member states.

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EXECUTIVE SUMMARY

ES-1 Objectives

The main objective of this study is to evaluate the viability of technologies for controlling emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) from industrial, commercial, and institutional (ICI) boilers. These pollutants contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. This source sector is coming under increased scrutiny by air quality regulators needing emission reductions to meet Clean Air Act requirements.

This study also includes a literature review of emission control costs and develops methods for estimating the costs and cost effectiveness of air pollution controls for ICI boilers. The study concludes that ICI boilers are a significant source of emissions, are relatively uncontrolled compared to electricity-generating units (EGUs), and offer the potential to achieve cost effective reductions for all three pollutants. The results of this technical and economic evaluation are intended as a resource in assessing regulatory and compliance strategies for ICI boilers.

Most of the technologies considered in this report have been successfully applied to the larger EGU boilers. This study investigates both the feasibility of down-scaling such control technologies for ICI boiler applications and of certain technologies that have not been applied to EGUs, but show promise for the ICI boilers.

ES-2 Report Organization

Chapter One provides an overview of the ICI boiler fleet in terms of boiler size, applications, fuel type and associated emissions. Chapters Two, Three, and Four discuss control technology options for NOx, SO_2 and PM, respectively. Each chapter provides: (1) descriptions of available control technologies; (2) a discussion of the applicability of these technologies to ICI boilers; (3) published cost estimates; and (4) an assessment of the impact of control technologies on overall facility efficiency. Chapter Five summarizes information about air pollution control equipment costs for ICI boilers calculated with the Coal Utility Environmental Cost (CUECost) model.

ES-3 Differences between ICI and EGU Boilers

ICI and EGU boilers differ in size, application, design, and emissions. Most commercial and institutional boilers are relatively small, with an average capacity of 17 MMBtu/hour. Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. By contrast, the average size of a coal-fired EGU boiler in the U.S. is greater than 2,000 MMBtu/hr.

All coal-fired EGUs in the United States are equipped with PM control devices and many have SO_2 and NOx emission controls. ICI boilers are significantly less likely to have air pollution control devices.

As part of this study, NESCAUM conducted a preliminary survey of the use of emission controls on ICI boilers in the Northeast. Survey results revealed that more than half of the units surveyed in the region had no controls; about one-third had PM controls, while very few units

had NOx controls. None of the surveyed units had SO_2 controls, although some have wet venturi scrubbers for PM control, which minimally reduce SO_2 emissions.

Technical, operational, economic and regulatory factors impose different opportunities and constraints on the applicability of air pollution control devices (APCDs) for EGU and ICI boilers. The following technical and operational characteristics must be evaluated in determining the potential applicability of emission controls for specific ICI boilers.

- Fuel type and quality – SO_2, PM, and NOx emissions from coal-fired boilers are typically higher than from those burning natural gas, oil, or wood waste. Some APCD technologies are not particularly sensitive to such variations. For example, an electrostatic precipitator (ESP) or a fabric filter (FF) can accommodate different PM concentrations, although the type and size of PM and gas temperatures will have an impact. Other controls that utilize reagents, such as SO_2 scrubbers and selective catalytic reduction or selective non-catalytic reduction (SCR/SNCR) technologies for NOx, are directly affected by fuel type and quality.
- Duty cycle – APCD controls must be capable of accommodating significant variation or cycling of boiler loads. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – The presence of equipment such as economizers or air preheaters has a direct impact on flue gas temperatures. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers, and SCR/SNCR that are widely used in EGUs may or may not be applicable to ICI boilers in certain cases.

ES-4 NOx Control Technologies

Emission control strategies for NOx can be divided into two basic categories: combustion modifications and post-combustion technologies. Control efficiency ranges and cost effectiveness ($/ton of NOx removed) for various technologies are provided in Table ES-1. Combustion modification technologies, which minimize the formation of NOx during the combustion process, include: combustion tuning; low-NOx burners and overfire air (LNBs and OFA); and gas, oil, or coal reburn.

LNBs have minimal effect on overall operating costs, but may introduce higher carbon monoxide and/or carbon levels in the fly ash, which reflect lower plant efficiency. In the case of gas reburn, operating costs are primarily a function of the fuel cost differential; for coal or oil reburn, fuel preparation costs (pulverization and atomization, respectively) represent the primary operating and maintenance costs. While gas reburn is easier to implement, the fuel differential costs are often prohibitive. The overall cost of low-NOx combustion technology installation depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity.

Post-combustion technologies reduce the amount of NOx exiting the stack that was formed during combustion. This group includes SNCR, SCR, and regenerative SCR (RSCR) technologies. Because the reaction occurs without the need for catalysts, SNCR systems have

lower capital costs, but achieve lower NOx reduction. SCR, on the other hand, is capital-intensive, but offers the opportunity for significantly greater NOx reductions because a dedicated reactor and a reaction-promoting catalyst ensure a highly controlled, efficient reaction. RSCR combines a regenerative thermal oxidizer with SCR technology, making it suitable for facilities with lower gas temperatures, such as those found in some ICI boilers. RSCRs can also reduce carbon monoxide emissions by half.

ES-5 SO_2 Control Technologies

SO_2 emission control technologies are post-combustion devices that utilize a process involving SO_2 reacting in the exhaust gas with a reagent (usually calcium- or sodium-based) and removal of the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 control technologies are commonly referred to as flue gas desulfurization (FGD) and/or “scrubbers” and are usually characterized in terms of the process conditions (wet vs. dry), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable). Wet scrubbers provide much greater levels of SO_2 control. Conventional dry processes include spray dryers (SDs) and dry sorbent injection (DSI). The capital costs of wet scrubbers are higher than those of dry scrubbers, although the cost effectiveness values (in dollars per ton of SO_2 removed) of wet and dry processes are similar. DSI technology has a significantly lower capital cost than wet or dry scrubbers and should therefore be more attractive for ICI boilers than conventional scrubbers.

In the eight-state NESCAUM region, residual oil is a common fuel for ICI boilers. Switching to a lower sulfur residual oil (for example, from 3 percent to 1 percent sulfur residual oil) can provide cost-effective SO_2 reductions. The cost of switching to lower sulfur distillate oil is much higher than switching to low sulfur residual oil, because the cost of distillate oil has been about twice that of residual oil in recent years. The cost effectiveness (in dollars per ton of SO_2 removed) from switching from residual fuel oil to distillate fuel oil is not as attractive and falls in the range of the cost effectiveness of installing a FGD scrubber.

ES-6 PM Control Technologies

Combustion processes emit both primary and secondary particulate matter. Primary emissions consist mostly of fly ash (e.g., non-combustible inorganic matter and unburned solid carbon). Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter. PM control technologies include: fabric filters or “baghouses,” wet and dry ESPs, venturi scrubbers, cyclones, and core separators. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired ICI boilers.

ES-7 Impact of Control Technologies on Operational Efficiency and Carbon Dioxide Emissions

Air pollution control technologies and strategies (e.g., fuel switching) can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative depending on technology and fuel choices.

Carbon dioxide (CO_2) emissions are primarily a function of the carbon content of fuels. However, the application of conventional pollutant control technologies can affect CO_2 emissions. This impact can vary widely among technologies within the same pollutant (e.g.,

LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. scrubbers for SO_2).

Combustion modification technologies for NOx have essentially no impact on the CO_2 emissions of the host boilers – with the noted exception of reburn when displacing coal or oil with natural gas – because the technologies do not impose any significant parasitic energy consumption (auxiliary power) requirements. With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy demand on the host boiler. These impacts include pressure, compressor, vaporization, and steam losses, and can range from 1–2 kW/1000 actual cubic feet per minute (acfm) for SNCR and up to about 4 kW/1000 acfm for SCR.

The major components affecting energy consumption for SO_2 systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. The power consumption of the SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. SO_2 controls have a range of potential parasitic losses, from duct injection representing about 1–2 kW/1000 acfm to wet FGD at as high as 8 kW/1000 acfm.

PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can be up to 10 kW/1000 acfm or higher.

ES-8 Cost Analysis

Cost is an important factor in evaluating the viability of air pollution control technologies. Information on capital and operating costs is more readily available for EGU than ICI boilers. Operating costs may be different for ICI boilers than utility boilers because of their size and the fact that they are typically located on smaller sites. Operating costs also include waste disposal and reagent use. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs, as a percentage of total capital cost, than those for utility boilers.

Cost estimates for ICI boilers with capacities ranging from 100 to 250 MMBtu/hr were generated by the CUECost model. This model, created by Raytheon Engineers for US EPA, was originally developed for large coal-fired EGUs and calculates capital and operating costs for certain pre-defined air pollution control devices for NOx, SO_2, and PM. The CUECost model produces approximate estimates (±30 percent accuracy) of installed capital and annualized operating costs. The CUECost model was adapted in this study for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. This study represents the first attempt to utilize a comprehensive cost model specific to ICI boilers.

Chapter Two contains a detailed discussion of the literature values for NOx control costs for ICI boilers. The NOx control costs for ICI boilers computed with CUECost were largely consistent with values reported in the literature. In terms of NOx removal, reported values were in the range of $1,000 to $3,000 per ton for LNBs or SNCR, and $2,000 to $14,000 per ton for SCR. The SCR costs for coal-fired ICI boilers appear to be consistent with the literature, although the CUECost capital cost values for residual oil were higher than the literature values. The capital costs for SNCR calculated from the CUECost models were in good agreement with literature values, particularly their sensitivity to boiler capacity. The capital costs for LNBs

calculated from CUECost for coal-fired boilers were consistent with the literature values, although the costs for residual oil-fired boilers were higher in CUECost than the literature values.

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs for ICI boilers. In terms of the cost per ton of SO_2 removed, reported values were in the range of $1,600 to $5,000 for spray dryers (SDs) and $1,900 to $5,200, for wet FGDs. The SO_2 capital costs computed with CUECost for SDs were in the range of the literature values at 250 MMBtu/hr. However, the capital costs computed by CUECost for wet FGDs were high compared to values reported in the literature.

Chapter Four contains a detailed discussion of the literature values for PM control costs. Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to industrial boilers. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM for coal and up to $15,000 per ton of PM for oil.

The dry-ESP control costs computed with CUECost were consistent with the literature values, although the CUECost predicted slightly higher values than reported by EPA for dry, wire-plate ESPs. The baghouse/fabric filter costs computed with CUECost were higher than the literature values for pulse-jet fabric filters.

This adaptation of CUECost model from EGUs to ICI boilers was intended to investigate the feasibility of estimating costs of controlling emissions of NOx, SO_2, and PM from ICI boilers. Further detailed work would be needed to validate this approach, but initial results included in this report are promising.

ES-9 Conclusion

ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. These boilers are relatively uncontrolled compared to EGUs and offer the potential to achieve cost-effective reductions for all three pollutants. A host of proven emission control technologies for EGUs can be scaled-down and deployed in industrial, commercial, and institutional settings to cost-effectively reduce emissions of concern. Other technologies that have not been applied to EGUs show promise for ICI boiler applications. Careful analysis will be needed to match the appropriate emission control technology for specific applications given: boiler size, fuel type/quality, duty-cycle, and design characteristics. Further, regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls.

Table ES-1. ICI Boiler Control Technologies

Pollutant	Technology	Control Efficiency	Cost Effectiveness $ per ton
NOx			
Combustion Modifications	Tuning	5-15%	current data not available
	LNB	25-55%	$750-$7,500
	Reburn	35-60%	current data not available
Post-Combustion	SNCR	30-70%	$1,300-$3,700
	SCR	70-90%	$2,200-$14,400
	RSCR	60-75%	$4,500
SO_2	Wet Scrubbers	95+%	$1,900-$5,200
	Spray Dryers	90-95%	$1,600-$5,200
	Dry Sorbent Injection	40-90%	current data not available
PM			
	Fabric Filters/Baghouses	99+%	$400-$1,000 – coal $6,900-$16,500- oil
	Wet/Dry ESPs	99+%	$160-$2,600 – coal $2,300 to $43,000 - oil
	Venturi Scrubbers	50-90%	current data not available
	Cyclones	70-90%	current data not available
	Core Separators	60-75%	current data not available

1 INTRODUCTION

1.1 Objectives

The main objective of this study is to evaluate various available control technologies and their cost effectiveness in reducing emissions of three pollutants: oxides of nitrogen (NOx), sulfur dioxide (SO_2), and primary fine particulate matter ($PM_{2.5}$) from industrial, commercial, and institutional (ICI) boilers. The study results should provide a strong technical and economic basis for developing cost-effective regulations and strategies to reduce emissions of these three major pollutants from ICI boilers.

1.2 Regulatory Drivers

Federal, state and local governments regulate all major criteria air pollutants under the authority of the Clean Air Act (CAA). The CAA mandates control of pollutants such as NOx, SO_2, and $PM_{2.5}$ to attain and maintain National Ambient Air Quality Standards (NAAQSs) for ozone and $PM_{2.5}$, reduce acidic deposition, and improve visibility under regional haze regulations. Emission standards for specific source categories, including ICI boilers, are also set by federal, state, and local governments to attain and maintain a NAAQS. Examples of these emission standards include New Source Performance Standards (NSPS), Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Reasonably Available Control Technology (RACT), and Best Available Retrofit Technology (BART).

States must formulate State Implementation Plans (SIPs) that provide a framework for limiting air emissions from major sources as part of a strategy for demonstrating attainment and maintenance of NAAQS. Some individual SIPs (if allowed by the state law) may set more stringent limits on emissions of NOx, SO_2, and $PM_{2.5}$ than required by the federal rules. However, states cannot set less stringent limits than required by federal rules and regulations. Generally, federal, state, and local permitting authorities rely upon available information on the latest advanced technologies for emission control when setting emission limits. Where applicable, permitting authorities require BACT and RACT in order to reduce air emissions from stationary sources. In areas that have not achieved a NAAQS (i.e., non-attainment areas), the CAA requires air pollution limits established by LAER for new major stationary sources and major modifications to existing stationary sources. BACT and RACT analyses consider the cost of controls. LAER control technologies, applicable to new major sources located in non-attainment areas, must be installed, operated and maintained without consideration of costs.

1.3 Characterization of Combustion Sources

1.3.1 Description of Combustion Sources

Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines.

Boiler size is typically represented in four ways: fuel input in units of MMBtu/hr, output of steam in lb steam/hr at a specified temperature and pressure, boiler horsepower (1 boiler hp = 33,475 MMBtu/hr), or electrical output in MWhr or MW (if electricity is generated).

The three main types of boilers are described below:

- *Firetube boilers*. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 MMBtu/hr.
- *Watertube boilers*. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a "wall." Watertube boilers vary in size from less than 10 MMBtu/hr to10,000 MMBtu/hr.
- *Fuel-firing*. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal (PC) enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to "suspend" the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

Boilers are also classified by the fuel they use – chiefly coal, oil, natural gas, wood, and waste byproducts.

1.3.2 Emissions by Size, Fuel, and Industry Sector

In 2005, Energy & Environmental Analysis, Inc. [EEA, 2005] estimated that there were 162,805 industrial and commercial boilers in the U.S., which had a total fuel input capacity of 2.7 million MMBtu/hr as summarized in Figure 1-1 and Table 1-1. This estimate included 43,015 industrial boilers with a total capacity of 1.6 million MMBtu/hr and 119,790 commercial boilers with a total capacity of 1.1 million MMBtu/hr. In addition, EEA estimated that there were approximately 16,000 industrial boilers in the non-manufacturing sector with a total capacity of 260,000 MMBtu/hr, but details on size distribution of these boilers were not provided because these units were not well characterized.

The EEA report divided boilers into two major categories (industrial and commercial) instead of the more common characterization as industrial, commercial, and institutional boilers. One segment of the ICI boiler population, identified as non-manufacturing industrial boilers, is not included in the EEA analyses due to a lack of sufficient data. The non-manufacturing segment accounted for only 11 percent of energy consumption in the industrial boiler population. The manufacturing and non-manufacturing segment of the population appear (from EEA's description) to correspond to what would be called industrial boilers. The commercial segment of the population includes what are designated in this report as commercial and institutional boilers. For example, there are several large boilers located at major institutions such as universities (e.g., Notre Dame, Cornell, etc.) and also several large boilers located at major hospitals (e.g., Massachusetts General Hospital) that belong in the institutional category instead

of the commercial sector. Thus, EEA's analysis appears to apply to most of the ICI boiler population, representing 89 percent of energy use by ICI boilers.

Industrial boilers were generally larger than commercial units. Sixty percent of the boilers in the manufacturing sector were greater than 100 MMBtu/hr in capacity, whereas 60 percent of the boilers in the commercial sector were in the range of 10 to 100 MMBtu/hr. The average capacity of the commercial boilers was 10 MMBtu/hr, with most less than 10 MMBtu/hr; the capacity of the average industrial boiler was 36 MMBtu/hr. Non-manufacturing boilers fell in between, at an average capacity of 16 MMBtu/hr. For industrial boilers, the average capacity factor was 47 percent (capacity factor is defined as the ratio of actual heat input in MMBtu to the maximum heat input based on nameplate capacity of the unit, calculated for a period of one year).

Table 1-1. Capacity of industrial boilers [EEA, 2005]

Unit Capacity	Manufacturing Boilers	Non-Mfg Boilers*	Commercial Boilers	Total
<10 MMBtu/hr	102,306	---	301,202	403,508
10-50 MMBtu/hr	277,810	---	463,685	741,495
50-100 MMBtu/hr	243,128	---	208,980	452,108
100-250 MMBtu/hr	327,327	---	140,110	467,437
>250 MMBtu/hr	616,209	---	33,639	649,848
Total Capacity, MMBtu/hr	1,566,780	260,000	1,147,617	2,714,397
Total Capacity >10 MMBtu/hr	1,464,474	---	846,415	2,310,889**
Total number of units	43,015	16,000	119,790	162,805
Average Capacity, MMBtu/hr	36	16	10	17

*No details provided on range of capacities
**Total does not include non-manufacturing boilers

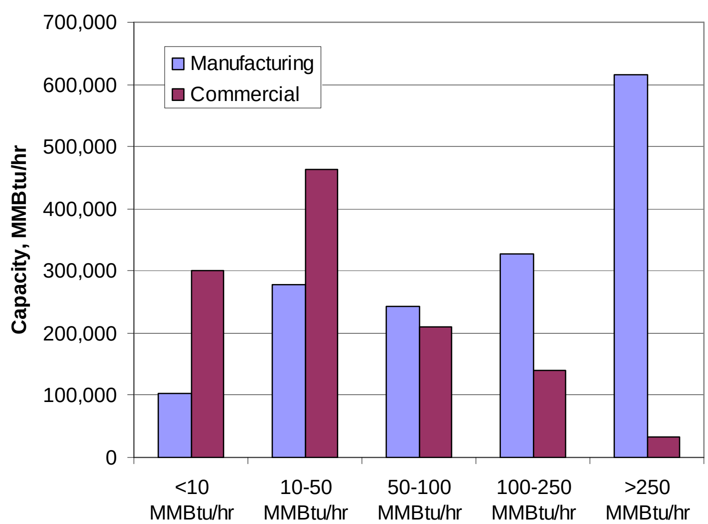


Figure 1-1. Total capacity of industrial boilers as a function of size [EEA, 2005]

Five major steam-intensive industries accounted for more than 70 percent of the boiler units and more than 80 percent of the boiler capacity of the manufacturing segment of industrial boilers: food, paper, chemicals, petroleum refining, and primary metals. The non-manufacturing segment of the industrial sector included agriculture, mining and construction. The largest categories in the commercial sector, by capacity, were schools, hospitals, lodgings, and office buildings.

Industrial boilers in the manufacturing sector are used to generate process steam and electricity. The fuels used in manufacturing boilers are related to the size of the boilers and, in some cases, the byproducts generated in the particular manufacturing process.

In the food production subsector, the average boiler capacity was 20 MMBtu/hr. The relatively small average capacity was reflected in the higher percentage (58 percent) of natural gas-fired boilers in the food industry than in any other major subsector, since very small boilers tend to burn natural gas.

The paper industry included some of the largest industrial boilers, with an average boiler size of 109 MMBtu/hr. The paper industry represented more than half (230,000 MMBtu/hr) of the total capacity of the manufacturing sector. More than 60 percent of the fuel used in paper industry boilers was wood (bark, wood chips, etc.) or black liquor, a waste product from the chemical pulping process.

The chemical industry employed both large and small boilers, with about seven percent of the units with capacities smaller than 10 MMBtu/hr, and a significant number (about 350 or 37 percent of total capacity) larger than 250 MMBtu/hr. The primary fuels for chemical industry boilers were natural gas (43 percent), process off-gas (39 percent), and coke (15 percent).

The refining industry had an average boiler size of 143 MMBtu/hr, the largest of any of the major industries, with over 200 boilers with capacities above 250 MMBtu/hr. By-product fuels (refinery gas or carbon monoxide) were the most common fuel source for boilers (58 percent), followed by natural gas (29 percent) and residual oil (11 percent).

About half of the total boiler capacity in the primary metals industry was from boilers larger than 100 MMBtu/hr. By-product fuels, like coke oven gas and blast furnace gas, provided the largest share (63 percent) of boiler fuel in the primary metals industry.

The remaining industries accounted for about 29 percent of manufacturing boilers (12,000 units) or about 18 percent of industrial boiler capacity. The average capacity for the rest of the manufacturing subsector was 23 MMBtu/hr. Approximately 100 boilers at other manufacturing facilities had capacities larger than 250 MMBtu/hr.

Unlike industrial boilers, which serve production processes, commercial boilers provide space heating and hot water for buildings. Natural gas fired the vast majority of commercial boilers, including 85 percent of commercial boiler units and 87 percent of the total commercial boiler capacity. About 10 percent of the commercial boilers were fired by oil. Coal was fired at about one percent of the commercial boilers, but represented five percent of the capacity, reflecting the larger size of commercial coal-fired boilers.

Figure 1-2 summarizes the total US boiler capacity in the manufacturing and commercial sectors as a function of fuel fired (left side of figure) and shows the average capacity per boiler (right side of figure) by fuel type. Coal-fired boilers were the largest in size on average. As discussed above, natural gas accounted for 70 percent of the total industrial boiler capacity in the

EEA survey. Coal and byproduct fuels accounted for about 10 percent each, with lesser capacity in oil- and wood-fired boilers.

In the manufacturing sector, the average coal-fired boiler capacity was about 180 MMBtu/hr, but the average capacity in both sectors combined was about 125 MMBtu/hr. Wood- and byproduct-fired boilers in the manufacturing sector were also large on average (120 and 110 MMBtu/hr, respectively). On the other hand, oil- and natural gas-fired boilers were small, on the order of 20 MMBtu/hr in the manufacturing sector and less than 10 MMBtu/hr in the commercial sector.

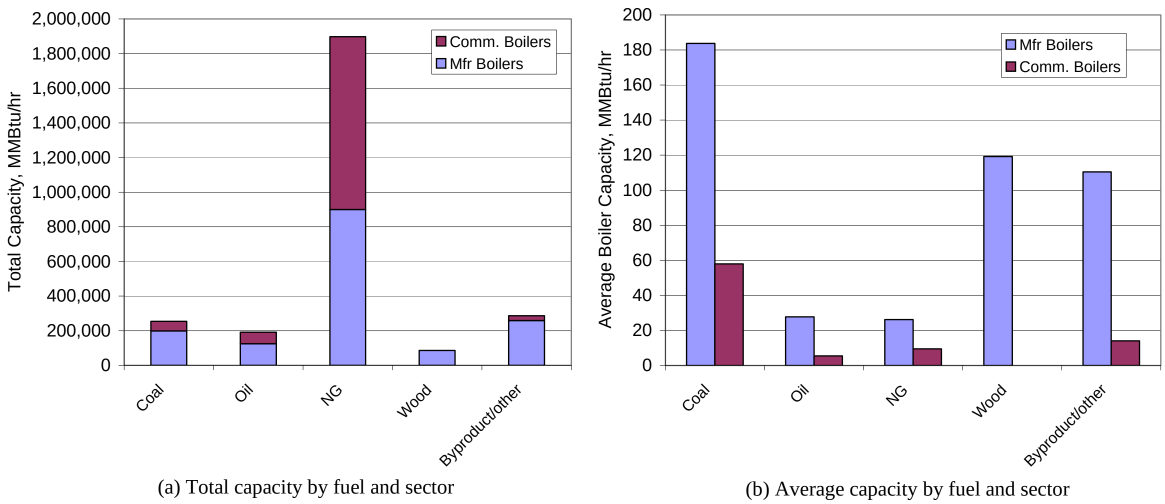


Figure 1-2. Total and average boiler capacity of U.S. industrial boilers as a function of fuel fired [EAA, 2005]

From EEA's 2005 study, the following general conclusions about boiler size for the entire U.S. ICI boiler population can be drawn:

- natural gas is the fuel fired at most ICI boilers;
- natural gas- and oil-fired boilers tend to be small, less than 20 MMBtu/hr in capacity;
- boilers fired with coal, wood, or process byproducts are larger in size, greater than 100 MMBtu/hr on average;
- although natural gas fired most of the ICI boilers in the U.S., coal, oil, and wood contribute substantially more to the emissions of SO_2 and PM; and
- all fuels are sources of NOx emissions.

One needs to be careful drawing conclusions for the eight-state NESCAUM region based on the national data in the EEA 2005 study because there are large region-to-region and state-to-state differences in boiler populations. For example, fuel oil is an important fuel in the Northeast, especially in rural areas where natural gas may not be available, while natural gas is predominant in other areas of the country.

A preliminary assessment of emissions from ICI boilers by pollutant in the U.S. and in the eight-state NESCAUM region was carried out using data from the AirData database via the EPA website (www.epa.gov/air/data). In this database, stationary sources, such as electric generating plants and factories, are identified individually by name and location. Figure 1-3 compares the annual emission of NOx, SO_2, and $PM_{2.5}$ in the U.S. with the eight-state NESCAUM region for 2002. Emissions in the NESCAUM region are about 5 percent of the US total emissions.

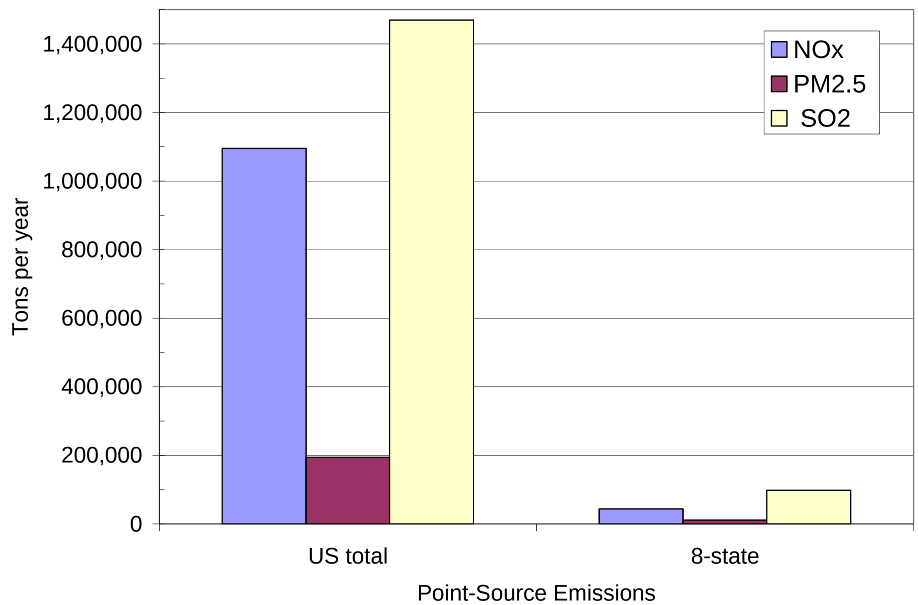


Figure 1-3 Total annual emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the U.S. and in the eight-state region from EPA AirData database

Another set of data from the eight-state region was extracted from the MANEVU 2002 non-road inventory (www.manevu.org). In this data set, oil-fired boilers were divided into distillate oil and residual oil-fired boilers (Figure 1-4).

NOx emissions in the eight-state NESCAUM region are mostly from oil- and gas-fired boilers. Because these are generally small boilers, combustion controls are good candidates for NOx control. For larger, coal- or wood-fired boilers, SNCR or SCR might also be applicable.

PM emissions are relatively low from coal-fired sources in the eight-state region, which suggests that most of the coal-fired sources already have particulate control devices. Oil- and wood-fired units have higher PM emissions, and PM emissions attributed to natural gas are quite small.

As might be expected, most of the SO_2 emissions from oil-fired boilers come from residual oil-fired boilers because of residual oil's higher sulfur content.

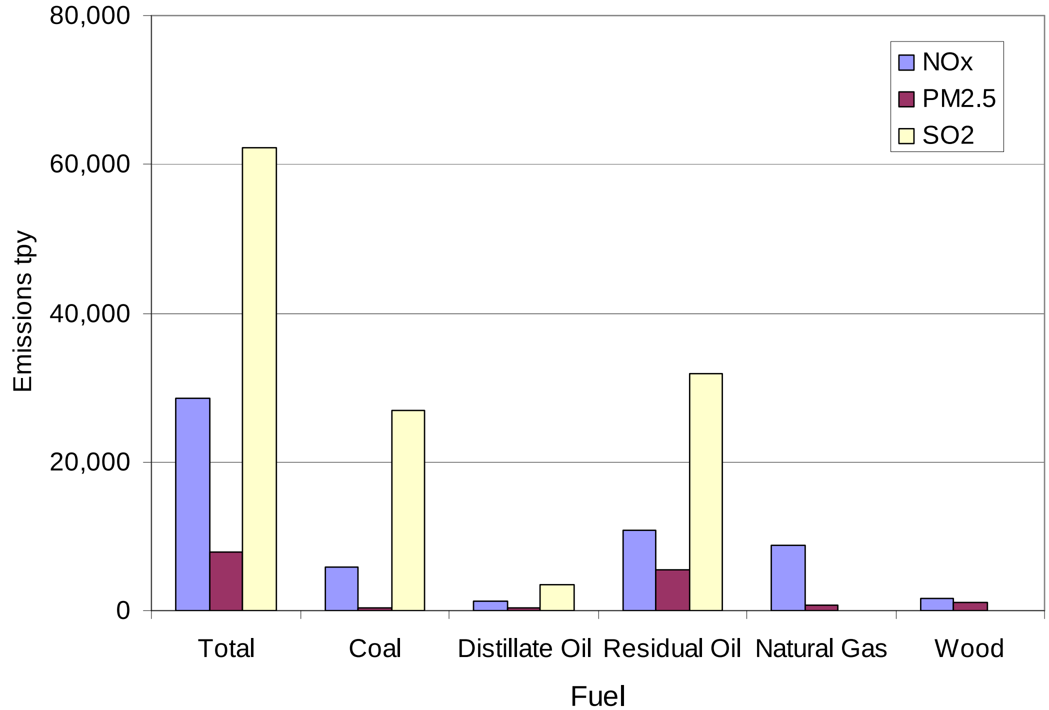


Figure 1-4. Emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the NESCAUM region from MANEVU database as a function of fuel fired

1.3.3 Differences between EGU and ICI boilers

EGU boilers produce steam in order to generate power. While ICI boilers do in some cases generate steam for electricity production, ICI boilers differ from EGUs in size, steam application, design, and emissions. Most commercial and institutional boilers are small, with an average capacity of 17 MMBtu/hour (Table 1-1). Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. The average size of a coal-fired EGU boiler in the U.S. is over 200 MW or over 2,000 MMBtu/hr.

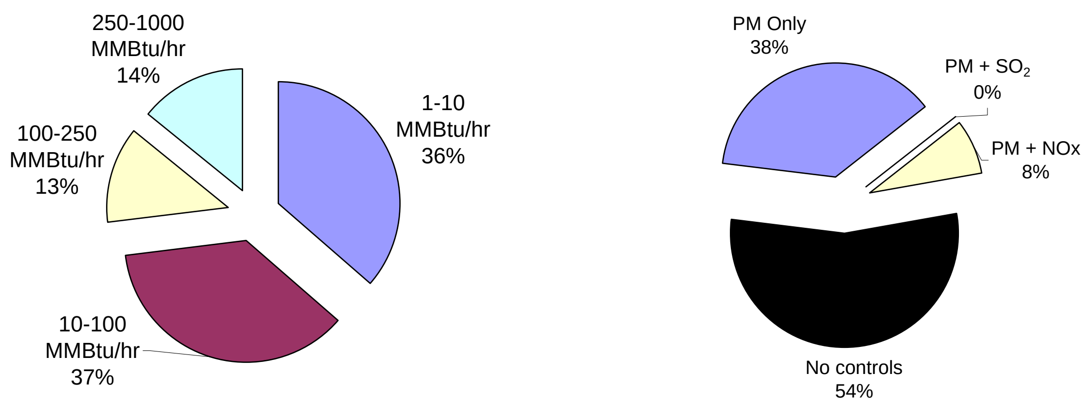
All coal-fired EGUs in the United States use control devices to reduce PM emissions. Additionally, many of the EGU boilers are required to use controls for SO_2 and NOx emissions, depending on site-specific factors such as the properties of the fuel burned, when the power plant was built, and the area where the power plant is located.

According to 1999 EPA Information Collection Request (ICR) responses from coal-fired EGUs, 77.4 percent of EGUs had PM post-combustion control only, 18.6 percent had both PM and SO_2 controls, 2.5 percent had PM and NOx controls, and 1.3 percent had all three post-combustion control devices [Kilgroe *et al.*, 2001]. Information from 2004 indicated that the fractions of total capacity of large coal-fired EGUs that have flue gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NOx controls were 38 percent and 37 percent, respectively [NESCAUM, 2005]. Since the 1999 ICR survey, additional NOx and SO_2 controls have been added at a rapid pace to coal-fired EGUs. It is presently not clear how

the implementation of NOx and SO_2 control technologies for EGUs would evolve as a consequence of the recent vacatur of Clean Air Interstate Rule (CAIR) by the U.S. D.C. Circuit.

In contrast to EGUs, ICI boilers are substantially less likely to have air pollution control devices. A study of industrial boilers and process heaters [USEPA, 2004] that looked at 22,117 industrial boilers and process heaters, which burned natural gas, distillate oil, residual oil, and coal, found that 88 percent had no air pollution control equipment.

A preliminary survey was undertaken as part of this study to evaluate the extent to which various emission controls were currently being applied to ICI boilers in the Northeast. These data were acquired from State Title V permits for solid-fueled (coal and wood) boilers as well as additional information from state personnel. The survey collected data in four states: Massachusetts, Vermont, New Hampshire, and New York. The data set was composed of 64 boilers – 47 wood-fired and 17 coal-fired. *Figure 1-5* illustrates the distribution of boiler capacity (by size) and the air pollution control devices (APCDs) in this data set. The full data set is summarized in Appendix A. As can be seen in *Figure 1-5(b)*, more than half of the units had no controls, about one-third had controls only for PM, and very few units had controls for NOx. There were no units with SO_2 controls, although some of the PM controls were wet venturi scrubbers, which might have a limited impact on SO_2 emissions.



(a) Distribution of capacity

(b) Distribution of APCDs

Figure 1-5. Solid-fuel boiler information from four northeast states, based on Title V permit information

There are several factors that directly or indirectly affect the reasons for the discrepancy in APCD deployment between EGU and ICI boilers. Technical and operational as well as business, economic, and regulatory factors impose different constraints and provide different opportunities for the applicability of APCDs for these two categories of boilers. The following discussion summarizes some of the important technical and operational issues.

Large, base-loaded EGUs operate mainly near maximum capacity or steam production. Industrial boilers typically do not run at maximum capacity, although this varies from one industry to another [EEA, 2005]. EGUs produce steam for electricity generation, while ICIs may produce steam for a variety of applications. The type of manufacturing is often more important

in determining boiler operation, or duty cycle (load vs. time) than manufacturing demand in general.

ICI boilers generate steam for processing operations for paper, chemical, refinery, and primary metals industries. Commercial boilers produce steam for a variety of processes, while institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities.

Another difference between EGU and ICI boilers is fuel diversity. EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), while ICI boilers tend to be designed for and use a more diverse mix of fuels (e.g., fuel by-products, waste, wood) in addition to the three conventional fuels above.

These differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of APCD applicability. Examples that directly affect APCD choice and applicability include equipment such as economizers or air preheaters, which affect the temperature of the flue gas at the stack. The differentiation in fuel usage also leads to different design parameters for emissions controls. For example, the iron and steel industry generates blast furnace gas or coke-oven gas, which is used in boilers, resulting in sulfur emissions. Pulp and paper boilers may use wood waste as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category.

These factors relate directly to APCD equipment choices and applicability. The following examples should help explain some of these impacts.

- Fuel quality – different fuels have different emission characteristics. SO_2, PM, and NOx emissions from coal fired boilers are different from those burning natural gas, oil, or wood waste. Some APCD technologies are not very sensitive to fuel quality variations (e.g., an electrostatic precipitator (ESP) may accommodate different levels of PM concentration, although the type and size of particles and gas temperatures will have an impact). However, others can be directly affected by changes in fuel quality and the resulting changes in pollutant concentrations in the flue gas to be treated (e.g., SO_2 and NOx controls that utilize reagents such as scrubbers for SO_2 and SCR/SNCR for NOx).
- Duty cycle – significant variation or cycling of boiler load requires APCD controls capable of accommodating such variations. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – the use of equipment such as economizers or air preheaters has direct impact on the resulting flue gas temperature. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers (wet and dry), and SCR /SNCR that are widely used in EGUs may or may not be applicable for some ICI boilers in such cases.

1.3.4 Control Technology Overview

A variety of emission control technologies are employed to reduce emissions of NOx, SO_2, and primary PM emissions. Technical details of control technologies for NOx, SO_2, and PM are discussed in Chapters Two, Three, and Four, respectively. Pollutant emission controls are generally divided into three major types given in the following list.

- *Pre-combustion Controls*. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls*. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Data on costs of pollution control equipment taken from the literature are reviewed in the individual technology chapters. In Chapter Five, an existing model for the estimation of air pollution control equipment costs for coal-fired EGUs (CUECost) is applied to ICI boilers burning different fuels (coal, oil, wood) with appropriate caveats and assumptions to provide reasonable and approximate control costs for ICI boilers.

1.4 Chapter 1 References

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2 NOx CONTROL TECHNOLOGIES

2.1 Introduction

This brief introduction applies to chapters Two, Three, and Four, which discuss control technology options for ICI boilers for NOx, SO_2, and PM, respectively. However, these chapters are not intended to provide detailed descriptions of the many available technologies for each pollutant. Significant literature is available for that purpose; in the context of this report, these chapters are intended to provide the reader with a general understanding of concepts, performance, applicability, and costs of the main technologies available. Further, in recognition of the concern with climate change, a brief discussion of energy consumption (parasitic power) associated with major technologies is included.

Specifically with respect to the deployment and applicability of air pollution controls, comparisons between ICI boilers and EGUs are relevant because of the more widespread application of pollution control equipment in the EGU sector. This was discussed in some detail in Chapter One. In addition, a few considerations specific to certain technologies and strategies are discussed, as appropriate.

2.1.1 ICI versus EGU Boilers

In general, the greater proliferation of air pollution control technologies in the EGU sector, as opposed to the industrial sector, seems to be driven by three dominant, differentiating factors.

- Size difference and associated emissions between the two: Because EGUs are much larger than ICI boilers, they have been targeted for environmental regulatory controls more heavily over the years.
- Technology costs: While not universally true, ICI boilers often have constraints due to their smaller sizes, diversity of plant layouts, and urban settings, all of which can have a negative impact on the costs of applying some of the control technologies. Conversely, and equally important, opportunities for lower-cost applications to ICI boilers do exist as a result of the smaller sizes, such as in the ability to have systems pre-fabricated and ready to erect onsite, as opposed to on-site construction requirements often needed with larger systems for EGUs.
- Cost recovery: The two sectors are significantly different from a fundamental business view, with EGUs being regulated entities, as opposed to openly competitive markets that exist within the ICI boiler population. This is important in that it affects how business decisions are made in the two sectors, how capital equipment purchases are funded, and also how ICI plants are designed and operated.

2.1.2 Control Technologies' Impact on Efficiency and CO_2 Emissions

Air pollution control technologies and strategies can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative and it is a function of the type of technology, as well as fuel choices.

An extreme example of this is the control of SO_2 from a coal-fired unit by two significantly different approaches: in one case, the use of an energy–intensive FGD "scrubber" penalizes the efficiency of such unit by up to 2 percent, resulting in a corresponding increase in CO_2 emissions; a very different and contrasting case, in which the unit chooses to reduce its SO_2 generation by switching from coal to natural gas, yields a corresponding and substantial decrease in its CO_2 emissions. Similarly, an efficient Low-NOx Burner (LNB) may replace an older burner and increase unit efficiency, while reducing NOx emissions, whereas a SNCR or SCR also reduces NOx, but will have some inherent parasitic power requirement that will have a negative impact on overall efficiency (and emissions of CO_2).

These chapters primarily address control technology options, as opposed to fuel switching strategies, except for SO_2. Switching from high-sulfur oil to low-sulfur oil is also discussed in Chapter 3. CO_2 impacts are well established as a function of the carbon content of fuels. The same applies in the case of renewable, carbon-based fuels (biomass). However, with control technologies, the impacts can vary widely among technologies for the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. wet and dry scrubbers for SO_2).

In general, efficiency impacts from application of air pollution control technologies can be divided into two major general areas:

- Direct impact (positive or negative) on the combustion process itself (e.g., changes in concentrations of O_2 or CO and in the amount of unburned carbon (UBC) in ash)
- Parasitic power associated with the particular technology or its components (e.g., increased gas pressure loss, power requirements for pumps/fans)

This parasitic power is given here in terms of electric power (kW) per flue gas flow rate (acfm) or kW/1000 acfm. These units are appropriate for several reasons:

- Most ICI boilers do not produce electricity, hence, size is more universally characterized by a parameter other than electrical generation (e.g., flow rate);
- Most control technology suppliers rank their equipment size in terms of gas flow rate as this is the dominant parameter for gas handling equipment sizing;
- If the objective is to "correlate" this parasitic power loss to an equivalent CO_2 impact, it can be done simply by knowing the size (acfm) of the technology application and the CO_2 emission profile of the equivalent kW generation (or savings) to offset the parasitic power loss.

2.2 Discussion of NOx Control Technologies

2.2.1 NOx Formation

The formation of NOx is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form NOx. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NOx emissions.

2.2.2 NOx Reduction

As a result of complex interactions in the formation of NOx, a variety of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NOx emission control is to divide them into two major categories: (1) those that minimize the formation of NOx itself during the combustion process (e.g., smaller quantities of NOx are formed); and (2) those that reduce the amount of NOx after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach under the "umbrella" of combustion modifications whereas technologies in the second category are termed post-combustion controls. Within each of these two categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NOx control than the application of a stand-alone technology.

2.2.3 Other Benefits of NOx Control Technologies

Some NOx control technologies have shown the potential to promote the capture of mercury (Hg) from the flue gas. Examples include combustion modification technologies (e.g., Low-NOx Burners and Overfire Air – though potentially with higher levels of unburned carbon) and post-combustion technologies (SCR – through the oxidation of mercury, making it more soluble and amenable to capture in a downstream process such as a scrubber for SO_2). This suggests that strategic and economic analyses for NOx controls need to also consider the potential impacts on mercury removal.

2.3 Summary of NOx Control Technologies

2.3.1 Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as LNBs, Overfire Air (OFA) or reburn (most often done with natural gas and called Gas Reburn - GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to reductions in NOx emissions of 5 to 15 percent or even higher in cases where a unit was originally badly “de-tuned.” It is important to remember that optimization results are truly a function of the “pre-optimization” condition of the power plant or unit (just as the improvement in an automobile from a tune-up depends on how badly it was running prior to it), and as such have limited opportunity for substantial emission reductions.

Development of “intelligent controls” – software-based systems that “learn” to operate a unit and then maintain its performance during normal operation, can also go a long way towards keeping plants well tuned, as they gain acceptance and become common features in combustion control systems.

2.3.2 Low-NOx Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NOx during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as “fuel or air staging”).

Figure 2-1. Low-NOx burner [TODD Dynaswirl-LN™]

Figure 2-1 shows a gas/oil Low-NOx burner. These technologies are prevalent in the electric power industry as well as in ICI boilers at present and increasingly used by ICIs, even at small sizes (less than 10 MMBtu/hr). Competing manufacturers have proprietary designs, geared towards application for different fuels and boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NOx reductions of 30 to 65 percent from uncontrolled baseline levels. Again, the type of boiler and the type of fuel will influence the actual emission reduction achieved.

Particularly for gas-fired applications, as in the majority of ICI boilers, advanced Low-NOx Burners, often referred to as ultra Low-NOx Burners (ULNBs), are commercially offered by several companies. Ultra Low-NOx Burners are capable of achieving NOx emission levels on the order of single digits in ppm. As with all technologies, “pushing the envelope” on emission levels requires increasingly more careful suitability analyses as well as a good understanding of operational constraints. Conversely, the advent of these very low-emission burners (less than 10 ppm NOx), allows units to achieve very low emission rates at costs well below post-combustion alternatives like SCR.

All combustion modification approaches face a common challenge of striking a balance between NOx reduction and decrease in fuel efficiency. The concern is exemplified by typically higher CO and/or carbon levels in the fly ash, which reflect lower efficiency and also the contamination of the fly ash itself, possibly making it unsuitable for reutilization such as in concrete manufacturing. This is a bigger concern for large EGUs than for ICI boilers due to the much larger quantities of ash produced and the associated costs of disposal.

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss). Low-NOx Burners are applicable to most ICI boiler types, excluding stoker types and Fluidized Bed Combustion units (FBCs).

2.3.3 Reburn

Reburn, while generically included in the “Combustion Modification” category, is different from the other technologies in this group (LNBs/OFA) in that it “destroys” (or chemically reduces) NOx shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, however, natural gas is the most common) into the boiler above the main burner region. A portion of the heat input from the primary fuel is replaced by the reburn fuel. Subsequently, this “fuel-rich” environment reacts with and destroys the NOx formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as popular as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. *Figure 2-2* shows a typical reburn system applied to a stoker boiler.

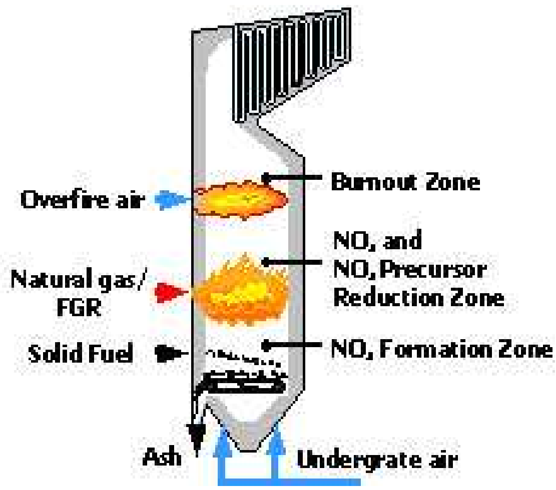

Figure 2-2. Gas reburn applied to a stoker boiler [www.gastechnology.org]

Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel, are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with a particular type of boiler – "Cyclone," – for which the previously mentioned technologies are not particularly well suited. However, this technology has been used only in large EGUs and is not a typical option for ICI boilers. Cyclone boilers are inherently high NOx emitters and are not an attractive option for new or retrofit units with increasingly lower NOx emission limits requirements.

Reburn performance has been shown to range from 30 to 60 percent reduction in NOx emissions, depending on such factors as reburn fuel type and quantity, initial NOx levels, boiler design, etc. Similar to the other combustion modification options, reburn can affect efficiency and fly-ash quality. As such, it requires the same optimum balance between NOx reduction and avoidance of negative impacts. On the other hand, reburn can be thought of as a "dial-in" NOx technology in that NOx reductions are, to a degree, a function of the amount of reburn fuel.

Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Reburn using coal or oil as the reburn fuel does not seem like a very attractive option for ICI boilers for technical reasons (boiler size, residence times), as well as the wider availability of similar performance options simpler to implement, such as LNBs. Gas reburn, while easier to implement, often has a prohibitive operating cost if, for example, natural gas is partially substituted for a less expensive primary fuel. Reburn is therefore an option for larger watertube-type boilers, including stokers, but require appropriate technical and economic analyses to determine suitability. Gas reburn has an impact on CO_2 emissions that is proportional to the type and quantity of fuels displaced (gas vs. coal or oil).

2.3.4 Post-Combustion Controls

Conventional, commercial post-combustion NOx controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NOx produced in the boiler to convert the NOx to harmless nitrogen and water. SNCR accomplishes this at higher

temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NOx. As noted below, SCR technology is capable of achieving much larger reductions in NOx emissions, higher than 90 percent, compared to the 30 to 60 percent reductions achievable by SNCR. *Figure 2-3* and *Figure 2-4* depict views of these two systems.

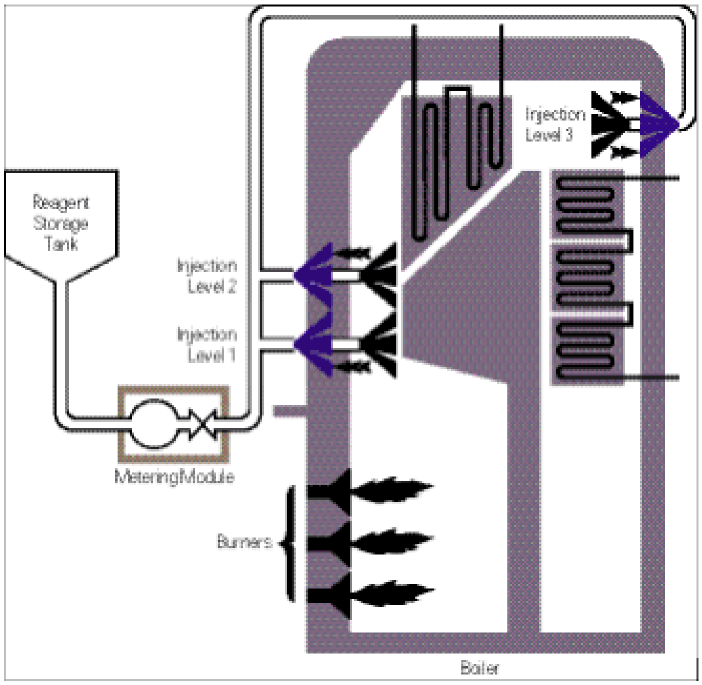

Figure 2-3. SNCR system schematic [FuelTech]

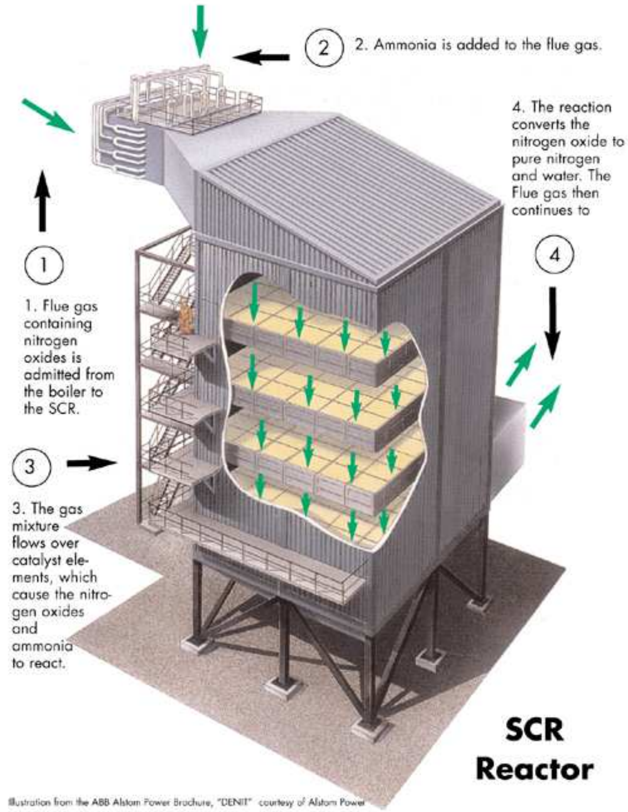

Figure 2-4. 3-D schematic of an SCR system [Alstom Power]

While the difference between the SNCR and SCR may seem minor, it yields significant differences in performance and costs. In the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the reaction vessel, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NOx); and finally, has lower NOx reduction capability (typically 30 to 50 percent, with some units achieving reductions in the 60 percent range). SCR, on the other hand, is capital intensive, but offers lower reagent costs and the opportunity for very high NOx reductions (90 percent or higher).

Costs are driven primarily by the consumption of the chemical reagent – usually (but not necessarily) urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NOx level and the desired percent reduction. It is also important to consider possible contamination of fly ash (in the case of coal firing) by ammonia making it potentially unable to be sold. This is, again, a bigger issue for larger EGU plants than for ICI boilers due to the size and quantities involved; as already stated, ICIs burning solid fuel do not typically sell their fly ash.

2.3.4.1 RSCR

Commonly, EGU boilers utilize SCR systems to reduce NOx emissions. However, a conventional SCR may not be cost-effective to retrofit into smaller units like ICI boilers because of the extensive modifications required to accommodate the unit. For some applications, the SCR may be located downstream of the particulate control equipment, where the flue gas temperature is much lower than the range of 650-750°F required for a conventional SCR (Toupin, 2007). These conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

If it is necessary to compensate for the reduction of flue gas temperatures, a regenerative selective catalytic reduction (RSCR™) system allows the efficient use of an SCR downstream of a particulate control device. The primary application of an RSCR system is the reduction of NOx emissions where the flue gas is typically at 300-400°F (Toupin, 2007). *Figure 2-5* illustrates the schematic and the actual RSCR system. *Figure 2-6* shows a block of ceramic heat exchanger.

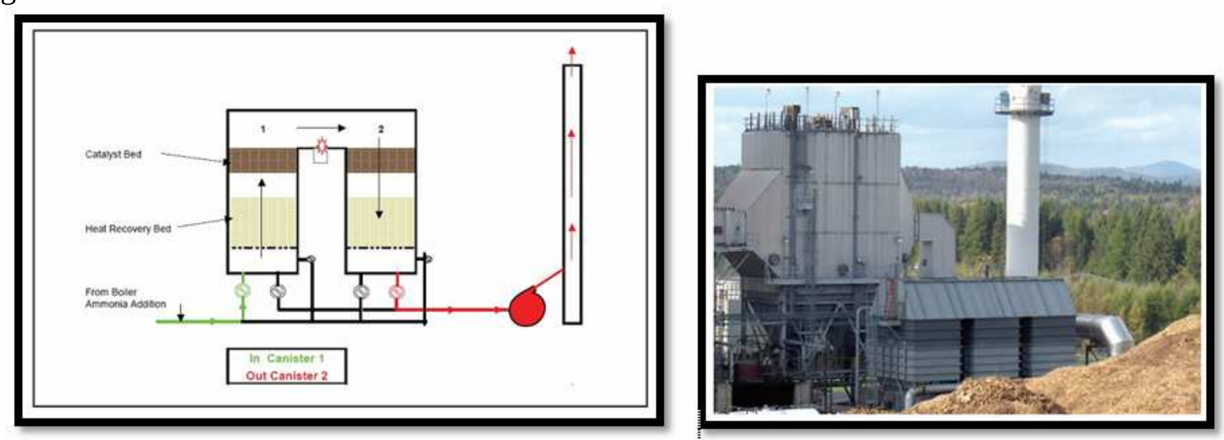

Figure 2-5. Schematic and actual RSCR [Toupin, 2007]

A direct-contact regenerative heater technology (i.e., burner), coupled with cycling beds of ceramic heat exchangers, is used to transfer heat to the flue gas. Additionally, some oxidation of CO to CO_2 in the flue gas occurs. The NOx reduction portion of the RSCR takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia can be used.

Figure 2-5 (left side) shows the working principles of the RSCR. Essentially, the flue gas in the space between the two canisters (called the retention chamber) is heated by the burner to make up for heat loss through the walls of the canisters and inefficiency in the ceramic heat transfer modules. This raises the temperature in the retention chamber by about 10-15ºF. The gas flows into the second canister, through the catalyst, and passes through the second ceramic module, which absorbs heat from the hot flue gas. Once this cycle is completed, the flow reverses, so that the second canister (which was just heated) becomes the inlet canister and the first canister becomes the outlet canister. The cycling between canisters accomplishes a similar function to the continuously rotating heating elements of a conventional regenerative air/gas heater.

Other components of the RSCR include the ductwork, fans, and the ammonia delivery system. Ductwork must be adequately sized to provide sufficient distance for ammonia mixing

and to minimize pressure drop. For the ceramic heat exchanger, factors that need to be taken into consideration during the design process are gas-side pressure drop, thermal efficiency, and cost. A large bed face area reduces the pressure drop and operating cost but increases capital cost. The ammonia delivery system consists of ammonia pumps, storage tanks, interconnecting piping, and a control system. The pump typically does not exceed one horsepower and often a redundant pump is provided to assure continuity in system operation [Toupin, 2007].

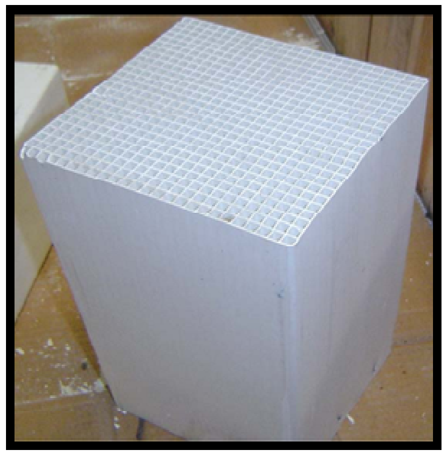

Figure 2-6. Block of monolith ceramic heat exchanger [Toupin, 2007]

The RSCR combines a regenerative thermal oxidizer (RTO) (e.g., retention chamber burner) with SCR technology. This ability to control flue gas temperatures allows for high NOx reduction under varying temperature conditions. *Table 2-1* shows the expected reduction in NOx and CO emissions [BPEI, 2006]. This study indicated that the RSCR is able to reduce NOx by 60 to 75 percent and CO by about 50 percent.

Table 2-1. CO and NOx reduction using RSCR [Source: BPEI 2006]

	Typical Stoker Design	**CO and NOx Reductions from Baseline**
Steam Flow lbs/hr x 10^3	100 – 500	
Steam Press, psi	600 – 900	
Steam Temp., °F	955 – 1000	
Unburned Combustibles Boiler Efficiency Loss (%)	1.0 – 1.5	
Furnace Retention sec.$^{(1)}$	3.0	
Grate Heat Release Btu/hr-ft	850,000 maximum	
Emissions:		
CO lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.30 (122 – 370)	Base
CO **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.05 – 0.15 (61 – 185)	(-50%)
NOx lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.15 – 0.25 (112 – 186)	Base
NOx **w/SNCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.17 (75 – 130)	(-30 to 40%)
NOx **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.06 – 0.075 (45 – 56)	(-60 to 75%)

Additionally, the heat exchanger part of the RSCR has a thermal efficiency of about 95 percent, which translates to fuel savings. Traditional technologies that utilize Ljungstrom or plate type heat exchangers for heat recovery and duct burners to reach the catalyst operating temperature are typically in the range of 70 to 75 percent thermal efficiency.

An analysis performed by BPEI on a typical 25 MW plant with a 75 percent reduction in NOx shows a cost effectiveness of $4,514 per ton of NOx removed. The cost breakdown is tabulated below in *Table 2-2*.

Table 2-2. RSCR cost efficiency [BPEI, 2008]

Plant Overview:	
Plant Gross MW	25
GROSS HEAT INPUT, MMBTU/HR	321
TYPICAL UNCONTROLLED NOx, LB/MMBTU	0.25
TYPICAL CONTROLLED NOx, LB/MMBTU	0.065
NOx REMOVED, TONS/YEAR	249.4
RSCR Cost:	
AMMONIA COST, $/TON NOx	$ 419
NATURAL GAS, $/ton NOx	$ 404
POWER COST, $/TON NOx	$ 589
CATALYST COST, $/TON	$ 555
CAPITAL COST, $/TON	$ 2,546
TOTAL COST PER TON NOx REMOVED	$ 4,514

Two RSCR installations (15 and 50MW) are currently in operation in the Northeast. The 15 MW plant uses whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of the two installations was to qualify for the Massachusetts Renewable Energy Credits (RECs). The state requirement for qualifying for RECs imposed a NOx level of 0.075 lb/MMBtu or less on a quarterly average basis.

2.3.5 Technology Combinations

In theory, most of the technologies described above can be used together. However, NOx reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NOx levels entering the SCR/SNCR system. Another combination offered commercially is the hybrid SNCR/SCR concept, which uses the excess ammonia (ammonia “slip”) of the SNCR to promote additional NOx reduction in a downstream SCR catalyst.

2.4 Applicability to ICI Boilers

The NOx control technologies previously described are commercially available and are used extensively in EGUs, but most are also applicable to ICI boilers. Because conventional fuels (e.g., coal, oil, gas) as well as alternative fuels (e.g., wood, petroleum coke, process off-gases) emit NOx, these technologies are applicable to most boilers using various fuels. With the exception of FBC and Stoker boilers, LNBs are available and widely used for most combinations of boiler types and fuels. OFA and reburn as well as SNCR and SCR technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility. As already stated, these include available space, residence times and gas temperatures. Conversely, other than firetube type boilers, these technologies are potential candidates for the other boiler types including stokers and FBCs. Finally, the RSCR may offer advantages for applications where low flue gas temperatures are present and a conventional SCR may be more costly to implement.

2.5 Efficiency Impacts

The NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the noted exception for reburn when displacing coal or oil with natural gas. This is because combustion modification technologies do not impose any significant parasitic energy consumption (auxiliary power). Note that combustion modification technologies can affect the resulting combustion conditions in addition to the desired reduction in NOx emissions. These impacts are reflected in varying temperatures, oxygen levels, and CO/UBC, all of which affect combustion efficiency as discussed previously. However, we do not attempt to quantify these impacts. The overriding assumption is that these NOx control technologies, once deployed, are optimized such that the resulting NOx emissions are achieved without compromising the above parameters (or at least their combined effects).

With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy impact on the host boiler. The losses attributable to these technologies include the following:

- For SNCR
  - compressor power (air atomization/mixing)
  - steam (if steam atomization/mixing)
  - dry gas loss (air injection into furnace)
  - water evaporation loss
- For SCR
  - compressor
  - reactor pressure loss
  - steam (sootblowing)

Table 2-3 summarizes the key parameters for major NOx control technologies.

Table 2-3. Summary of NOx control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impacts (kW/1000 acfm)	Comments
LNB	All except Stokers, FBC	30 – 60 (<10ppm possible on gas)	NA	Assumed not to have negative impact on $CO/UBC/O_2$
OFA	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
Reburn	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
SNCR	All except firetube (Must have adequate temperature window)	30 - 70	1 - 2	Compressor/vaporization losses
SCR	All (Most likely for larger coal units where LNBs cannot reach very low NOx levels)	60 - 90	0.5 – 1 (gas) 2 - 4 (oil/coal)	Pressure loss/steam

2.6 NOx Control Costs

The following tables summarize published NOx control costs for ICI boilers reported in the literature [US EPA, 1996; NESCAUM, 2000; Khan, 2003; US EPA, 2003; MACTEC, 2005; Whiteman, 2006]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of NOx removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some operating costs. Costs of reagents and fuels (e.g., ammonia, natural gas) and consumables (e.g., SCR catalyst) change with time, but not always at the general rate of inflation. Some of these costs have increased at rates higher than the general rate of inflation. Thus, cost effectiveness values (or operating costs) from before 2005 have not been reported.

Table 2-4 summarizes the published NOx control costs for combustion modification technologies. The cost of the installation of low-NOx combustion technology depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity (*Figure 2-7*). Smaller boilers (10 to 50 MMBtu/hr) are often firetube or packaged watertube, whereas larger oil and gas boilers are more likely to be field-erected watertube boilers. Coal-fired boilers can be stokers, pulverized coal (PC), or cyclones. Combustion modification technologies therefore need to be evaluated on a case-by-case basis, taking into account both the fuel and the design of the combustion system. For the substantial majority of the estimates for ICI boilers, capital costs are in the range of $1,000 to $6,000 per MMBtu/hr. Cost effectiveness values, where available, are generally in the range of $1,000 to $7,000 per ton of NOx removed.

Table 2-4. NOx control costs for combustion modifications applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
Overfire Air	15-30	Coal	500	$2,682	1996		1
Fuel-Lean GR	35%	Coal	350	$1,302	1999		2
Gas Reburn	55%	Coal	500	$2,604	1999		2
LNB	25%	Coal	350	$6,378	1999		2
LNB	36.0%	Coal	350	$6,378	1999		2
LNB	50%	Coal	500	$8,464	1996		1
LNB	51%	Coal	100	$9,287	1999		6
LNB	51%	Coal	250	$7,055	1999		6
LNB	51%	Coal	1000	$4,654	1999		6
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,383	3
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,988	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$2,636	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$3,101	3
LNB	40%	Pulv. Coal	250	$346-$3,610	2005	$749-$3,393	3
LNB	45.0%	Resid. Oil	250-FT	$5,088	2005	$6,361-$7,483	3
LNB	50%	Resid. Oil	250-WT	$5,088	2005	$4,691-$5,519	3
LNB	40%	Resid. Oil	250	$346-$5,088	2005?	$1,505-$6,813	3
LNB	45%	Resid. Oil	10	$7,617	1996		1
LNB	45%	Resid. Oil	50	$3,021	1996		1
LNB	45%	Resid. Oil	150	$1,563	1996		1
LNB	45%	Dist. Oil	10	$7,617	1996		1
LNB	45%	Dist. Oil	50	$3,021	1996		1
LNB	45%	Dist. Oil	150	$1,563	1996		1
LNB	25%	Gas	350	$6,378	1999		2
LNB	40%-55%	Gas	10	$7,617	1996		1
LNB	40%-55%	Gas	50	$3,021	1996		1
LNB	40%-55%	Gas	150	$1,563	1996		1
LNB+FGR	50%	Pulv. Coal	250	$930-6,629	2005	$1,482-$3,582	3
LNB+FGR	72%	Pulv. Coal	250	$930-6,629	2005	$1,029-$2,488	3
LNB+FGR	50%	Resid. Oil	250	$930-6,629	2005	$2,977-$7,197	3
LNB+FGR	72%	Resid. Oil	250	$930-6,629	2005	$2,068-$4,998	3
LNB+OFA	51%-65%	Coal	100	$9,287	1999		6
LNB+OFA	51%-65%	Coal	250	$7,055	1999		6
LNB+OFA	51%-65%	Coal	1000	$4,654	1999		6
LNB+OFA	30%-50%	Oil	100	$3,258	1999		6
LNB+OFA	30%-50%	Oil	250	$2,474	1999		6
LNB+OFA	30%-60%	Oil	1000	$1,633	1999		6
LNB+OFA	60%	Gas	100	$3,258	1999		6
LNB+OFA	60%	Gas	250	$2,474	1999		6
LNB+OFA	60%	Gas	1000	$1,633	1999		6

Table 2-4 [continued]

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
ULNB	46%	Pulv. Coal	250	$1,364	2005	$1,876	3
ULNB	63%	Pulv. Coal	250	$1,364	2005	$933	3
ULNB	72%	Pulv. Coal	250	$1,364	2005	$619	3
ULNB	75%	Pulv. Coal	250	$1,364	2005	$784	3
ULNB	85%	Pulv. Coal	250	$1,364	2005	$692	3
ULNB	75%	Resid. Oil	250	$1,364	2005	1575	3
ULNB	85%	Resid. Oil	250	$1,364	2005	1390	3
ULNB	80%	Dist. Oil	24.5	$8,619	2005	17954	3
ULNB	80%	Dist. Oil	70	$2,280	2005	5756	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4751	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4564	3

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1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, “Selective Non-Catalytic Reduction Technology Costs for Industrial Sources,” memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

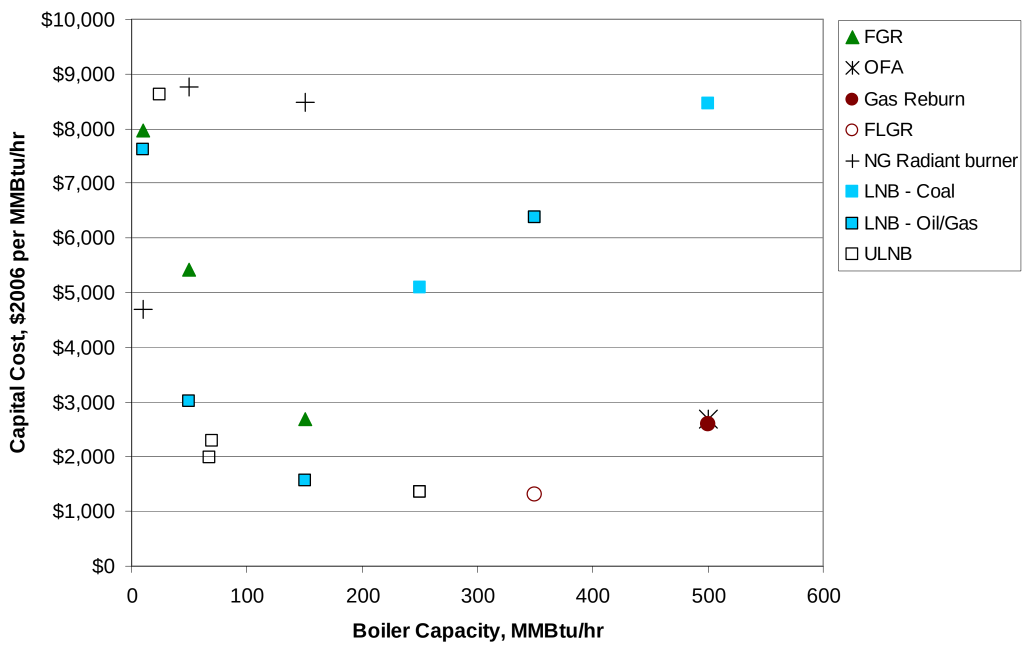

Figure 2-7. Capital cost for NOx control for combustion modification applied to ICI boilers as a function of boiler capacity

Table 2-5. NOx control costs for SNCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SNCR	30%-70%	Coal	500	$2,044	1996		1
SNCR	40%	Coal	100	$6,717	1999		6
SNCR	40%	Coal	250	$5,102	1999		6
SNCR	40%	Coal	1000	$3,366	1999		6
SNCR	30%-70%	Resid. Oil	50	$4,297	1996		1
SNCR	30%-70%	Resid. Oil	150	$4,297	1996		1
SNCR	35%		350	$2,862	1999		2
SNCR			21	$17,101	2006	$3,718	4
SNCR			120	$6,377	2006	$2,231	4
SNCR			240	$4,493	2006	$1,821	4
SNCR			387	$2,899	2006	$1,564	4
SNCR			543	$2,319	2006	$1,538	4
SNCR			844	$1,449	2006	$1,346	4
SNCR	40%	Oil	100	$5,205	1999		6
SNCR	40%	Oil	250	$3,954	1999		6
SNCR	40%	Oil	1000	$2,608	1999		6
SNCR	30%-70%	Dist. Oil	50	$4,297	1996		1
SNCR	30%-60%	Natural Gas	50	$4,297	1996		1
SNCR	40%	Gas	100	$5,372	1999		6
SNCR	40%	Gas	250	$4,082	1999		6
SNCR	40%	Gas	1000	$2,693	1999		6
LNB+SNCR	50%-89%	Pulv. Coal	250	$2,064-6,829	2005	$1,409-$4,473	3
LNB+SNCR	50%-89%	Resid. Oil	250	$2,064-6,829	2005	$2,229-$7,909	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

Table 2-5 summarizes the published NOx control costs for SNCR applied to ICI boilers. As with combustion modifications, the capital cost of SNCR systems is sensitive to the type of combustion system. As long as the boiler has sufficient space for installation of injection lances and mixing of reagent and flue gas (at the appropriate temperature), the capital costs should not depend on the fuel burned. The relationship between capital cost and boiler capacity is shown in *Figure 2-8*. Except for the 1996 EPA estimates for gas and oil boilers, there is a pronounced effect of boiler capacity on capital cost. The graph shows that fuel type is probably secondary to boiler capacity, although there will be an indirect effect of fuel, because fuel type influences the design of the combustion system. The cost effectiveness for SNCR was given by ICAC [Whiteman, 2006] without regard to fuel type and by MACTEC [2005] for coal and residual oil.

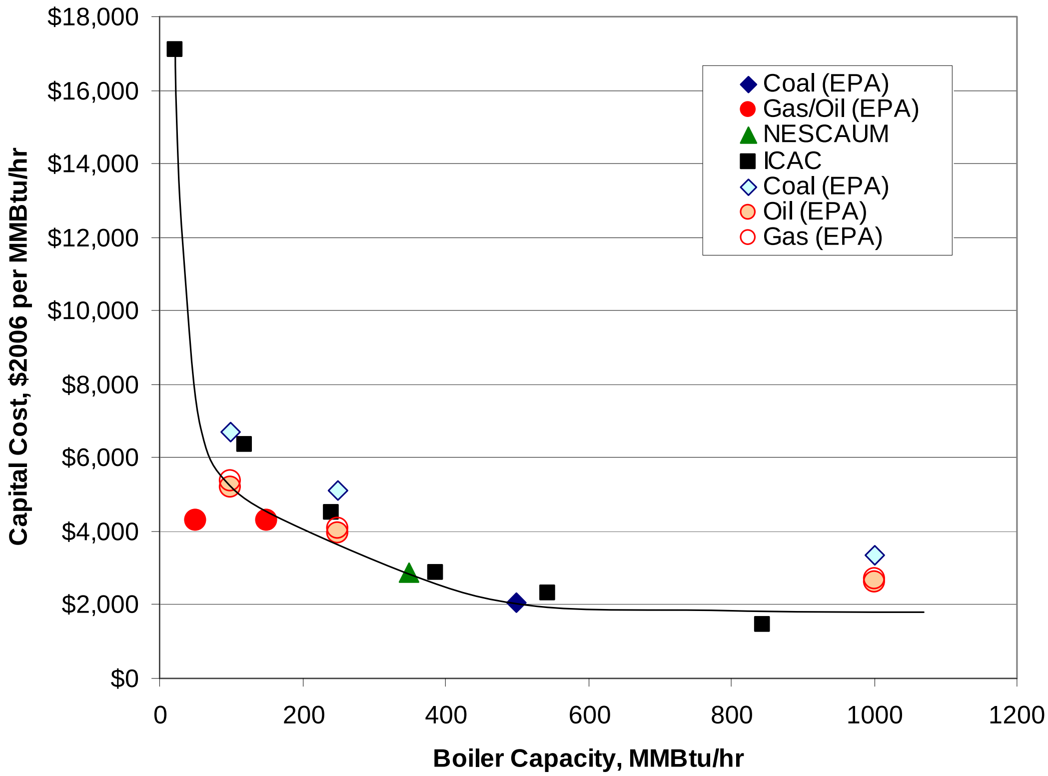

Figure 2-8. Capital cost for NOx control for SNCR applied to ICI boilers as a function of boiler capacity

Table 2-6 summarizes the published NOx control costs for SCR. The relationship between capital cost and boiler capacity is shown in *Figure 2-9*. The capital cost of SCR systems is sensitive to the type of fuel and to the level of NOx reduction desired, but not to the combustion system. The volume of catalyst required for an SCR installation depends on the level of desired NOx reduction and on the fuel. Coal-fired power plant applications are the most expensive, since the flue gas entering the SCR contains fly ash, which affects the design of the catalyst. The capital cost for a given fuel and boiler size can vary (see, for example, the variation in capital costs reported for coal application). When an SCR must be retrofit, the cost of the installation depends on the configuration of the specific system. Because the amount of

ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

Table 2-6. NOx control costs for SCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SCR	80%	Coal	*350*	$12,755-19,133	1999		2
SCR	80%-90%	Coal	500	$15,365-16,145	1996		1
SCR	70%-90%	Pulv. Coal	250	$1,666-13,881	2005	$2,233-$7,280	3
SCR	80%	Coal	100	$18,574	1999		6
SCR	80%	Coal	250	$14,110	1999		6
SCR	80%	Coal	1000	$9,309	1999		6
SCR	80%	Oil	100	$14,116	1999		6
SCR	80%	Oil	250	$10,723	1999		6
SCR	80%	Oil	1000	$7,075	1999		6
SCR	--	Oil	--	$5,102-7,653	1999		5
SCR	70%-90%	Resid. Oil	250	$1,666-13,881	2005	$4,363-$14,431	3
SCR	80%-90%	Resid. Oil	50	$8,359	1996		1
SCR	80%-90%	Resid. Oil	150	$4,909	1996		1
SCR	80%-90%	Dist.	50	$8,359	1996		1
SCR	80%-90%	Dist.	150	$4,909	1996		1
SCR	80%	Gas	100	$10,216	1999		6
SCR	80%	Gas	250	$7,760	1999		6
SCR	80%	Gas	1000	$5,120	1999		6
SCR	80%	Gas	100	$9,566	1999		2
SCR	80%	Gas	350	$7,015	1999		2
SCR	80%-90%	Natural Gas	50	$8,359	1996		1
SCR	80%-90%	Natural Gas	150	$4,909	1996		1
SCR	80%	Wood	350	$6,378-7,653	1999		2
SCR	74%	Wood	321	$1,978	2006	$4,514	7

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
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5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.
7. BPEI. (2008, February). RSCR Cost Effective Analysis.

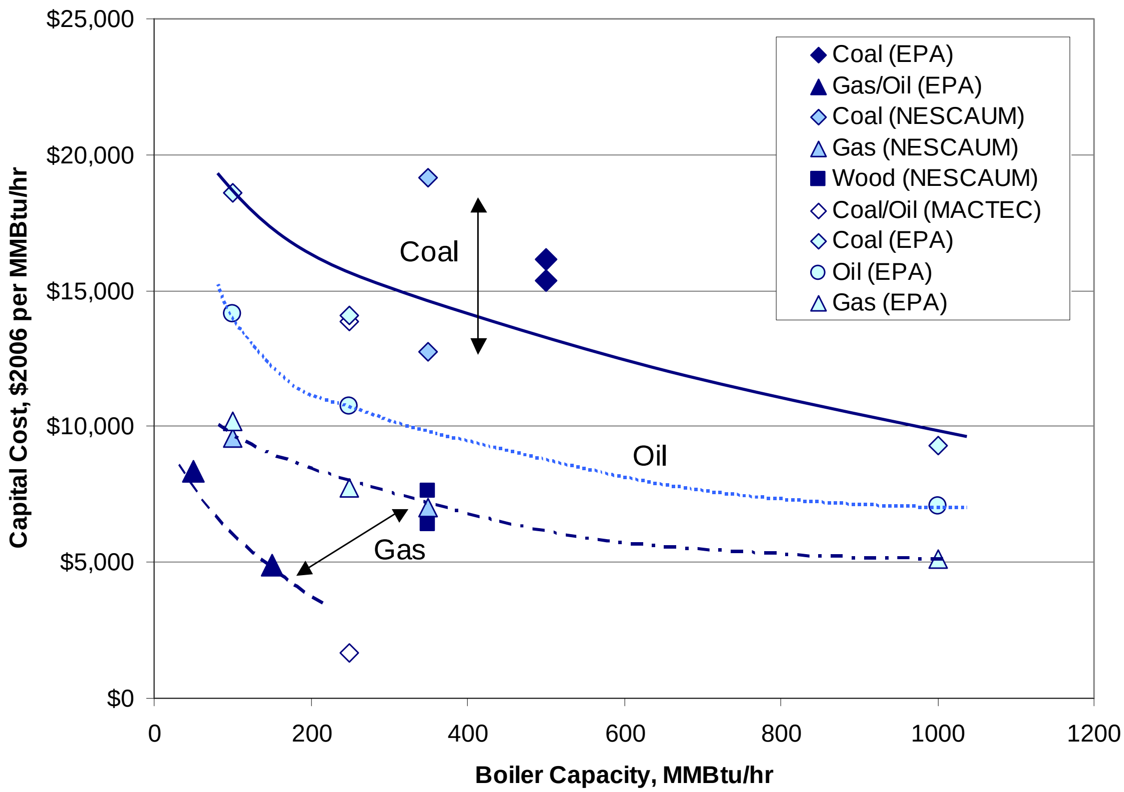

Figure 2-9. Capital cost for NOx control for SCR applied to ICI boilers as a function of boiler capacity

2.7 Chapter 2 References

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3 SO_2 CONTROL TECHNOLOGIES

3.1 SO_2 Formation

SO_2 is an undesirable byproduct of the combustion of sulfur-containing fossil fuels. SO_2, like NOx, is a precursor to ambient fine particles: Thirty to 50 percent of ambient fine PM mass in the eastern U.S. is attributable to sulfate derived from SO_2. SO_2 is a significant contributor to wet and dry acid deposition on various ecosystems (lakes, streams, soils, and forests). Various coals in the U.S. can have 1 to 3 percent (by mass) sulfur; residual oil (No. 6 oil) can have sulfur contents of 2 percent and higher. Distillate oils are generally lower in sulfur content (less than 0.5 percent by mass). Natural gas has essentially zero sulfur content. However, unlike nitrogen in coal or oil, essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics). This means that the relationship between sulfur content in the fuel and SO_2 emissions is much more direct and linear than that between fuel nitrogen and NOx emissions, and as such, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal or from higher-sulfur oils to lower-sulfur oils) are directly proportional to the difference in sulfur contents of fuels.

Another important difference is that this relationship is, for all practical purposes, independent of the type of boiler technology. Two exceptions to this include the high–alkaline nature of ash in some sub bituminous coals, which causes a portion of the sulfur in the coal to react and form various sulfate salts (mostly calcium sulfate); another is the combustion of coal in fluidized bed combustion (FBC) boilers where the lower temperatures of combustion and the use of alkaline material (e.g., limestone) in the "bed" promote the reaction of SO_2 with calcium to form sulfate, thereby reducing the net emissions of SO_2. In practical terms, this means that most solid- and liquid-fuel-fired systems produce SO_2 emissions proportional to their sulfur content, whereas natural gas combustion produces essentially no SO_2.

Additionally, despite the much smaller quantities of SO_3 formed in comparison to SO_2, as noted above, SO_3 presents both operational and environmental challenges. Operationally, SO_3 is a concern because if the temperature of the back-end flue gas handling equipment (e.g., ducts, particulate control devices, scrubbers) falls below the acid dew point, corrosion and material deterioration can result. From an environmental perspective, nucleation and condensation of ultra-fine sulfuric acid particles formed from the SO_3 present in the flue gas can contribute to the primary emissions of fine PM from the stack into the atmosphere.

3.2 SO_2 Reduction

As a result of the relationship between fuel sulfur content and SO_2, SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. This is accomplished by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers" and are usually

described in terms of the process conditions (wet vs. dry), methods for gas-sorbent contact (e.g., absorber vessel vs. duct for dry sorbent injection), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction, and the use of enhancing additives. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability to ICI boilers, and data on performance and cost. For a more detailed description of FGD technologies, see Srivastava [2000].

As noted earlier, SO_2 control strategies can also include fuel switching (from high-sulfur coal to low-sulfur coal or from high-sulfur oil to low-sulfur oil/natural gas). While not considered a "technology," switching from a higher-sulfur fuel to a lower-sulfur one requires considerable cost and operational analysis. Major issues include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

3.3 Other FGD Benefits

Significant attention has been given recently to the issue of mercury emissions from EGUs and ICI boilers. It is relevant to note that some FGD technologies have been shown to capture mercury from the flue gas [Jones and Feeley, 2008] by absorbing the water-soluble oxidized forms of mercury from the flue gas. Both wet and dry SO_2 control processes have been and are being tested to determine their mercury capture potential. This suggests that strategic and economic analyses for SO_2 control technologies need to consider the potential side-benefit of mercury removal as well.

3.4 Summary of FGD Technologies

A brief overview of FGD technologies is provided here to give the reader a broad perspective on SO_2 controls.

3.4.1 Wet Processes

Wet FGD (WFGD) or "wet scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s [NESCAUM 2000]. They represent the predominant SO_2 control technology in use today with over 80 percent of the controlled EGUs capacity in the world and the U.S. [EPA 2000].

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield >90 percent SO_2 capture. Currently, advanced scrubber designs for EGUs have eliminated not only many of the early operational problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with the technology being capable of well over 95 percent SO_2 control [Dene *et al.*, 2008]. *Figure 3-1* provides a schematic view of a wet scrubber.

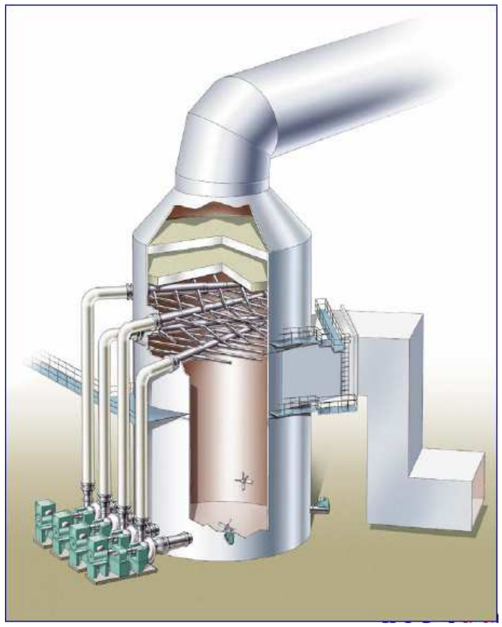

Figure 3-1. Schematic of a WFGD scrubber [Bozzuto, 2007]

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate, ammonia, and even seawater-based processes are all commercially available. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, and efficiency targets.

Technology costs have changed over time, as expected, reflecting changes in market conditions, labor and raw material costs, local, state, regional, and federal regulatory drivers, and site-specific considerations. Recently, capital costs have trended upward after a downward trend in the mid-late 1990s. These fluctuations have in large part, been driven by labor and material costs, the global nature of technology markets, and regulatory changes within the electric power sector [Sharp, 2007; Cichanowicz, 2007].

3.4.2 Dry Processes

Conventional dry processes include spray dryers (SDs) or “dry scrubbers” and Dry Sorbent Injection (DSI) technologies, and are shown in *Figure 3-2* and *Figure 3-3*, respectively. The technologies are referred to as “dry” because the SO_2 sorbent, while it may be injected as a slurry or a dry powder, is finally dried and collected in a conventional particulate control device, a fabric filter, or an ESP.

SD refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber vessel. DSI technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the “reactor,” and several configurations are possible based on the temperature window desired. This can occur at the furnace (1800-2200ºF), economizer (800-900ºF), or in a low-temperature duct (250-300ºF). In addition,

another common feature of dry scrubbing systems is the need for the particulate control equipment downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (although, depending on the application, ESPs may be used) that are not only efficient collectors of fine particulates, but can also provide some additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the bags. Dry processes are more compatible with low- to medium-sulfur coals because of the need to limit solid concentrations in the slurry below a threshold for adequate atomization and the need to limit the amount of solids collected in an existing particulate control device. This requirement precludes higher sulfur fuel applications where the required amount of reagent would be above that threshold. Therefore, high-sulfur applications are more typically associated with wet FGDs.

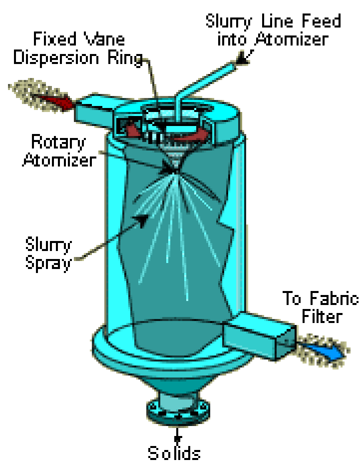

Figure 3-2. Schematic of a spray dryer [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

It is relevant to note that DSI technology did not gain any meaningful market penetration as part of the EGU compliance options to meet the requirements of the 1990 CAAA (Title IV) “acid rain” legislation for reducing emissions of SO_2. The large number of wet FGD installations in response to the Clean Air Act of 1970, and creation of “emission allowances,” combined with the trend to switch fuels (mostly to low-sulfur Powder River Basin or PRB coal) in response to the 1990 CAAA, help explain this situation. However, more recently, interest in DSI technology applications for ICI boilers has been renewed and companies are “revamping” the knowledge base for DSI.

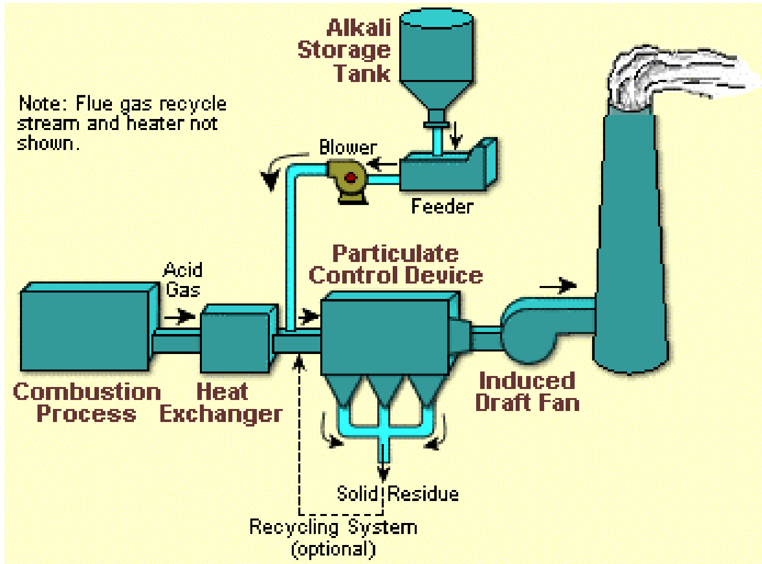

Figure 3-3. Dry Sorbent Injection (DSI) system diagram
[http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector. Companies such as O'Brien and Gere [Day, 2006; Day, 2007] and Siemens Environmental [Siemens, 2007] are marketing and deploying duct injection systems, and Nalco Mobotec [Haddad *et al.*, 2003] offers furnace sorbent injection (FSI) systems for ICI boilers. O'Brien and Gere, for example, have conducted over 5,000 hours of demonstrations at 15 different boilers since January 2005 to evaluate the viability, performance, and economics of DSI [Day, 2007]. These processes require relatively little new equipment and are thus suitable candidates for ICI boiler retrofit applications, where site constraints (e.g., space) are often critical.

Two examples of DSI systems are Furnace Sorbent Injection (FSI) in which hydrated lime is injected into the upper furnace of the boiler, and Lime Slurry Duct injection (LSDI) where atomized lime slurry is sprayed into the gas stream in the duct. FSI systems were first demonstrated in the 1980s on EGU boilers and are currently operating at ICI boilers [Dickerman, 2006].

FSI systems are capable of removing between 20 to 60 percent of the SO_2 and have shown removal percentages of as high as 90 to 99 percent for HCl and SO_3 [Haddad *et al.*, 2003]. The FSI systems also offer a low capital cost option and the attractiveness of quick cost recovery for ICI boiler sector [Dickerman, 2006].

The LSDI utilizes an atomized spray of lime slurry. The particles are subsequently captured in the downstream particulate collector. Sorbent particle size distribution is important for maximizing SO_2 capture while minimizing operational problems such as duct fallout and deposition.

LSDI systems have been utilized to mitigate plume generation from cement plants, and are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent [Dickerman, 2006].

In either case, both dry sorbent injection technologies offer an economical method for reducing emissions of SO_2. *Table 3-1* compares the FSI and LSDI systems for a 100 MW boiler, burning coal with one percent sulfur.

Table 3-1. Comparison of price for FSI and LSDI systems for a 100 MW coal-fired boiler [Dickerman, 2006]

Parameter	***FSI (Hydrated Lime)***	***LSDI***
SO_2 Removal	35%	50%
Reagent Cost ($\$10^3$/yr)	$1,400	$370
Parasitic Power ($\$10^3$/yr)	$182	$182
Disposal Cost ($\$10^3$/yr)	$168	$93
Subtotal ($\$10^3$/yr)	$1,750	$645
Capital Cost ($/kW)	$1,000,000 (10 $/kW)	$2,500,000 (25 $/kW)
Annual Capital Charge ($\$10^3$/yr)	$100	$250
Total Operating Cost ($\$10^3$/yr)	$1,850	$895
$/ton SO_2 Removed	$1,070	$311

Trona (sodium sesquicarbonate) is another reagent that has shown potential to reduce SO_2 emissions. A typical flow diagram is shown in *Figure 3-4* for injection of trona into a duct.

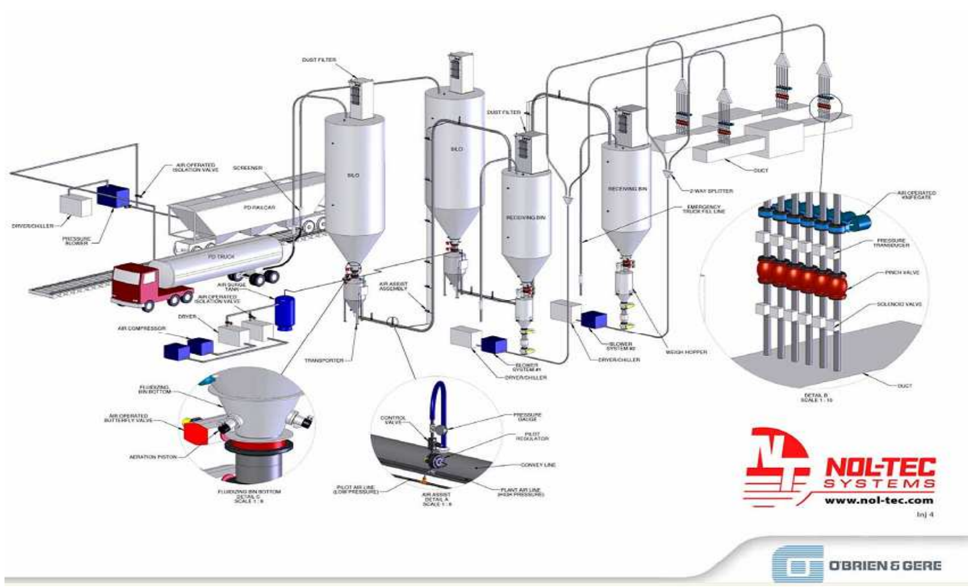

Figure 3-4. Flow diagram for trona DSI system [Day, 2006]

Trona's higher reactivity compared to lime helps it to offset the reaction stoichiometry advantage of lime. More importantly, due to the ability of trona to capture SO_2 when injected at higher temperatures [Cremer *et al.*, 2008], it is potentially applicable to many ICI boilers where flue gas temperatures may be higher that the desired ~300°F required for lime. *Figure 3-5* gives

some test data showing percent SO_2 reduction, [Day, 2006], averaged over several applications for units with ESPs.

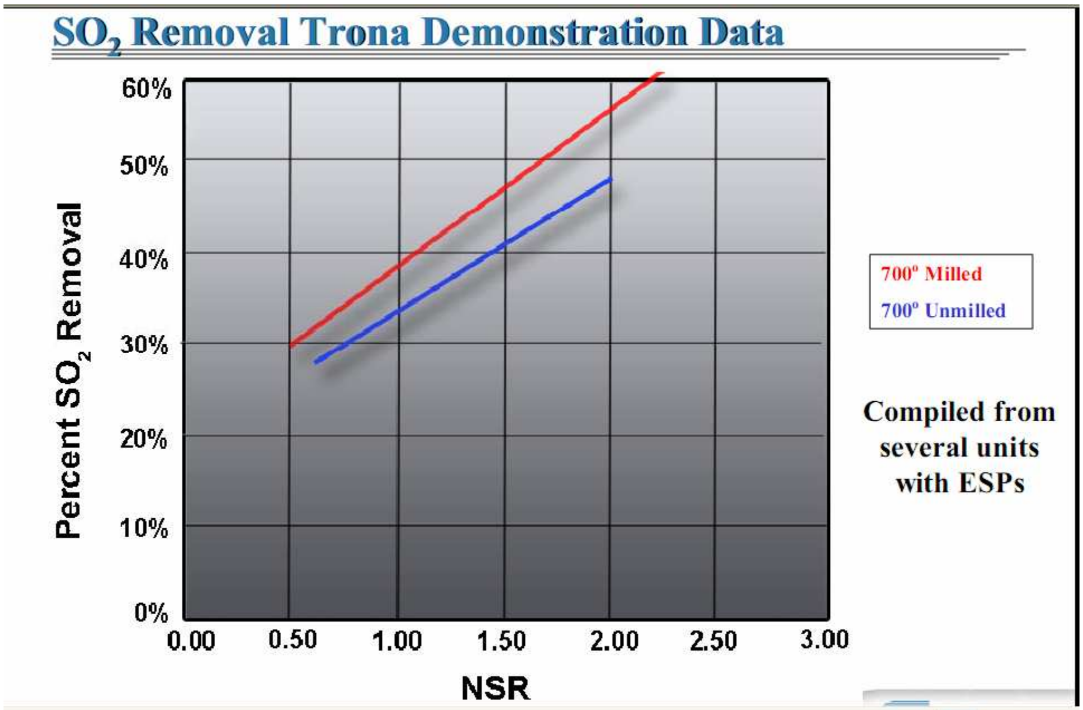

Figure 3-5. SO_2 removal test data [Day, 2007]

Figure 3-5 presents results for SO_2 reduction as a function of normalized stoichiometric ratio (NSR), which is the ratio of the reagent (trona in this case) to SO_2 in the flue gas. The two lines depict SO_2 reduction potential for two different sizes of trona at the same flue gas temperature of 700°F. Larger particles (unmilled) result in lower SO_2 reductions, as expected, relative to the milled condition (smaller particle size).

3.4.3 Other SO_2 Scrubbing Technologies

A number of other scrubber technologies have been developed for control of SO_2, but have not to date received significant market share. Among them are sodium- and ammonia-based wet scrubbing technologies. Some of these technologies, like the activated coke process [Dene, 2008], are regenerable (meaning the reagent can be regenerated and used repeatedly) and may produce useful byproducts, such as sulfuric acid, elemental sulfur, and ammonium sulfate. *Table 3-2* and *Table 3-3* present a comparison of the key performance characteristics and attributes for several alternative scrubbing technologies compared with conventional wet and dry scrubbers [Bozzuto, 2007].

Table 3-2. Comparison of alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	**Spray Dryer**	**Ammonia WFGD**	**Sodium WFGD**
Features	• High Efficiency • Low cost reagent • Byproduct flexibility	• Low investment cost • Dry byproduct • Small footprint • No liquid waste	• High value byproduct • Economics improved at high sulfur levels • Low operating cost	• Low investment cost • Operational simplicity
Pros	• Small flue gas flow • Operational simplicity required • Acute capital cost • Short evaluation period	• Low/medium sulfur fuel • Smaller flue gas flow • Short evaluation period	• High sulfur fuel • Larger flue gas flow • Gypsum market •Medium cost evaluation period	• High sulfur fuel • Larger flue gas flow • Fertilizer market
Cons	• Effluent discharge issue	• Limited landfill area • High lime/limestone cost ratio	• Acute capital cost sensitivity • Ultra-low PM emission requirements	• Acute capital cost sensitivity
Reagent	Limestone	Lime	Ammonia	Caustic, soda ash
Byproduct	Marketable gypsum or landfill	Landfill	Fertilizer	Sodium sulfate
SO_2 inlet	High	Low/medium	High	High
Removal Efficiency	>98%	90 – 95%	>98%	>98%

Table 3-3. Cost estimates for alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	**Spray Dryer**	**Ammonia WFGD**	**Sodium WFGD**
Capital Cost ($/acfm)	25 – 45	15- 25	35 – 60	10 – 20
Power Consumption (kW/acfm)	3-6	2	3-6	2-3
Reagent Cost ($/ton SO_2 removed.)	$15 – 25/ton	$60 – 75/ton	$80 – 105/ton	$100-130/ton
Byproduct Cost ($/ton SO_2 removed.)	$12 – 20/ton – disposal ($15/ton) – sale	$12 – 20/ton	$150 – 250/ton	??

3.5 Use of Fuel Oils with Lower Sulfur Content

Distillate fuel (No. 2 oil) is used in combustion systems in which an atomizer sprays droplets of oil into a combustion chamber and the droplets burn in suspension. Residual fuel oil (No. 6 oil) is also atomized and burned in ICI boilers. No. 6 oil is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of No. 6 oil in industrial combustion systems. A wide range of sulfur contents are available, from less than 0.3 wt% to greater than 3 wt%.

For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2. There is also an additional and important benefit of reduced emissions of $PM_{2.5}$. There are generally costs associated with switching to lower-sulfur fuels, which will undoubtedly vary from region to region.

Table 3-4 shows an example of the stocks of the fuel oils available on the East Coast and in the U.S. in 2006, taken from the Energy Information Administration (EIA) Petroleum Supply Annual [US EIA, 2006]. Substantial stocks of low-sulfur No. 6 fuel oil (less than 0.3 percent sulfur) and of ultra-low-sulfur No. 2 fuel oil (less than 0.0015 percent sulfur) were available both in the U.S. and on the East Coast.

Table 3-4. Distillate and residual oil stocks in 2006 (x1000 barrels) [US EIA, 2006]

	East Coast		U. S. Total	
Distillate Fuel Oil	**4,174**		**31,318**	
0.0015% sulfur and under	1,856	(44%)	16,531	(53%)
Greater than 0.0015% to 0.05% sulfur	560	(13%)	6,223	(20%)
Greater than 0.05% sulfur	1,758	(42%)	8,564	(27%)
Residual Fuel Oil	**2,486**		**11,936**	
Less than 0.31% sulfur	869	(35%)	1,291	(11%)
0.31 to 1% sulfur	975	(39%)	2,544	(21%)
Greater than 1% sulfur	642	(26%)	8,101	(68%)

Figure 3-6 shows the prices for residual oil and distillate oil from 1983 through 2007. The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been narrowing in recent years. The price of distillate oil in recent years, however, has been at times twice as much as the price of residual oil. The EIA prices for residual oil do not include a breakdown for very low sulfur residual oil (less than 0.31 percent sulfur). However, the prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm S), low-sulfur (15-500 ppm S), and high-sulfur (>500 ppm S). These prices, shown in *Figure 3-7*, do not show much difference in price as a function of sulfur content of No. 2 oil.

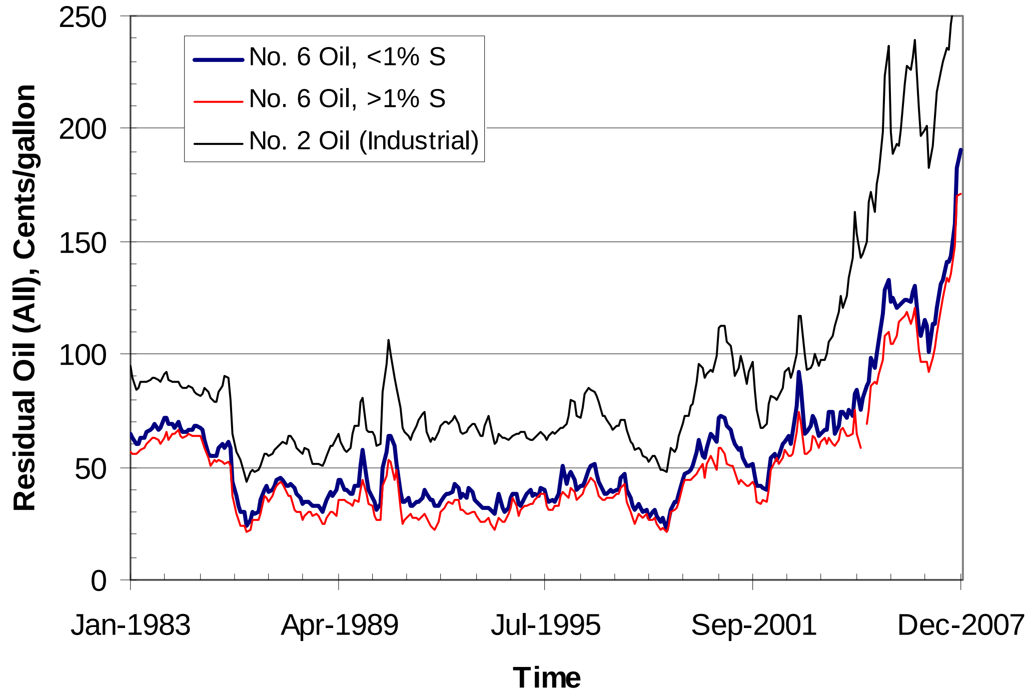

Figure 3-6. Industrial energy prices for No. 6 oil greater than 1 percent S, No. 6 oil less than 1 percent S, and No. 2 oil [Source: US EIA, 2008]

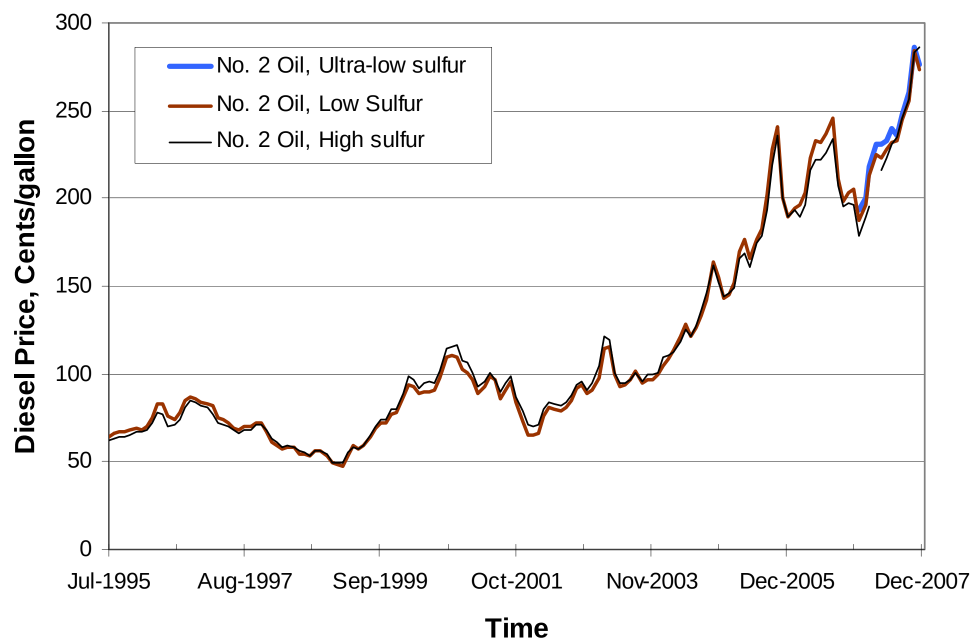

Figure 3-7. Industrial energy prices for No. 2 (distillate) oil [Source: US EIA, 2008]

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example, in which December 2007 fuel prices are used. If the high-sulfur residual oil is assumed to be 3 percent S, the low-sulfur residual oil is assumed to be 1 percent S, and the distillate oil is assumed to be 0.2 percent S, then the cost for fuel switching is shown in *Table 3-5*. These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in *Table 3-5* suggest that switching from a 3 percent sulfur residual fuel oil to a low-sulfur residual oil (1 percent S) would provide a cost-effective sulfur removal strategy at about $771 per ton of SO_2 removed. The cost of switching to distillate oil is estimated to be much higher than switching to low-sulfur residual oil, because the cost of distillate oil has been as much as twice that of residual oil in recent years. The cost effectiveness of a wet FGD for 90 to 99 percent SO_2 removal is in the range of $2,000 to $5,200/ton SO_2 (see Section 3.8). Thus, a switch to lower-sulfur fuel represents a cost-effective sulfur-compliance strategy for residual oil-fired boilers. The cost effectiveness (in dollars per ton of SO_2 removed) of switching from residual fuel oil to distillate fuel oil is not as attractive and is in the range of the cost effectiveness of installing a FGD or scrubber.

Table 3-5. Example of costs of switching to low-sulfur fuel oil [Fuel Prices from US EIA, 2008]

Fuel Switch	**SO_2 reduction**	**$/ton SO_2 removed (2007$)**
From 3% S to 1% Residual Oil*	66.7%	$771
From 3% S Residual to 0.2% Distillate**	93.6%	$5,335

*Assuming December 2007 prices for <1%S and >1%S residual oil
**Assuming December 2007 prices for >1%S and distillate oil

3.6 Applicability of SO_2 Control Technologies to ICI Boilers

The technologies described above are commercially available and are used extensively throughout the electric utility industry for coal-firing applications. The EGUs have deployed SO_2 controls (mostly wet and dry scrubbers) since the 1970s. ICI boilers firing coal are good candidates for the application of SO_2 control technologies. At least one oil-fired installation of a wet FGD has been noted in the literature [Caine and Shah, 2008]. Economics, however, will dictate preferred options on a case-by-case basis. It is likely that the higher capital-cost intensive technologies (e.g., wet and dry scrubbers) will be most attractive to larger ICI boilers, whereas the injection technologies (such as DSI) would likely be favored at smaller ICI boilers. The annualized cost of a wet FGD scrubber using wet sodium or alkaline waste can be lower relative to lime and limestone FGD, especially if low-cost waste disposal is available and the amount of SO_2 to be removed is small [Emmel, 2006]. This would suggest that smaller ICI boilers may not be good candidates for high capital-cost FGD systems. However, they should be good candidates for application of lower capital cost technologies such as DSI.

In terms of applicability, it is also important to recognize the impact of sulfur content of coal. Dry scrubbing has been typically restricted to low and medium sulfur coals (less than 2 wt% S) due to economic and technical considerations, including constraints associated with sorbent slurry concentration and adequate atomization performance. Lastly, while theoretically feasible, fluidized bed combustion (FBC) boilers are low emitters of SO_2 due to their inherent combustion process (bed temperature and composition), and are not likely candidates for SO_2 scrubber systems.

3.7 Efficiency Impacts

From the brief descriptions above, it should be clear that the common thread among the major SO_2 control technologies involves the reaction of SO_2 in the flue gas with a sorbent or reagent. The chemical reaction occurs either in a dedicated vessel (scrubber), or in the existing flue gas duct system. The major components affecting energy consumption for these systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. As expected, the energy penalties associated with a highly efficient (99 percent SO_2 reduction) wet scrubber are higher than for a less energy-intensive technology such as DSI.

The power consumption of SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. In other words, SO_2 control performance is related to reagent utilization, commonly referred to as liquid-to-gas (L/G) ratio for wet systems and normalized stoichiometric ratio or reagent (Ca or Na) to-sulfur ratio for dry technologies. This can be explained based on the fact that for a given SO_2 reduction level, lower quantities of reagent not only translate to lower reagent costs, but also to lower energy costs.

Table 3-6 summarizes performance and energy efficiency impacts for the three general SO_2 technologies discussed. It is important to note the values shown in the table, specifically in the “Energy Impact” column, represent nominal ranges based on generic combustion calculations and parasitic energy consumption for each technology. They are not site- or fuel-specific calculations, which are generally dependent on many variables, such as fuel composition, combustion and steam efficiencies, and operating conditions (e.g., excess air). However, these values represent broad, industry-wide averages for impacts of SO_2 control technologies on efficiency.

Table 3-6. Summary of energy impacts for SO_2 control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)
WFGD	Larger coal units, high sulfur coals, excluding FBC	90 - 95+	4 – 8+
Dry Scrubbers (SDs)	Larger units w/ low/medium sulfur coals, excluding FBC	70 – 90+	2 - 4
Duct Injection	Larger units w/ low/medium sulfur coals (FBC applications possible for additional “SO_2 trim”)	30 – 60+	1 - 2

3.8 SO_2 Control Costs

Table 3-7 summarizes published SO_2 control costs for ICI boilers, as reported in the literature [Khan, 2003; US EPA, 2003; Whiteman, 2003; MACTEC, 2005]. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars/ton of SO_2 removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs, and reagents or consumables can make up a large portion of some of the operating costs. Costs of reagents and fuels (e.g., limestone, trona) change with time, but not always at the general rate of inflation. Thus, cost effectiveness values (or operating costs) from years before 2005 are not shown in the table. *Table 3-7* summarizes the published SO_2 control costs for a number of SO_2 control technologies.

A range of capital costs has been reported for sorbent injection technologies. *Figure 3-8* shows costs for dry duct injection (e.g., trona injection), wet duct injection (e.g., LSDI), and furnace sorbent injection (FSI). There was a large range of capital costs reported for dry sorbent injection. Wet sorbent injection (e.g., injection of hydrated lime slurry) was reported to have a significantly lower capital cost than dry sorbent injection. FSI capital costs were between dry and wet duct injection. The cost effectiveness (cost in dollars per ton of SO_2 removed) depends on the specific sorbent used and the stoichiometric ratio of sorbent to SO_2.

Table 3-7. SO_2 control costs applied to ICI boilers

Technology	SO_2 Reductio n Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, \$2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness (\$/ton @Base Yr)	Ref
In-Duct Dry Sorbent Inj.	40%	High-S Coal	100	$34,228	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	250	$24,028	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	1000	$15,954	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	100	$22,953	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	250	$16,565	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	1000	$11,031	1999		1
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	100	$17,327	2003		3
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	250	$12,624	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	100	$8,663	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	250	$4,703	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	1000	$4,641	2003		3
Furnace Sorbent Inj.	70%	Coal	100	$26,609	2003		3
Furnace Sorbent Inj.	70%	Coal	250	$14,851	2003		3
Furnace Sorbent Inj.	70%	Coal	1000	$7,054	2003		3
Spray Dryer	90%	Coal	100	$69,744	1999		1
Spray Dryer	90%	Coal	250	$46,209	1999		1
Spray Dryer	90%	Coal	1000	$25,861	1999		1
Spray Dryer	90%	Coal	250	$13,300-188,820	2005	$1,712-3,578	4
Spray Dryer	95%	Coal	250	$13,300-188,820	2005	$1,622-3,390	4
Spray Dryer	90%	Oil	250	$13,300-188,820	2005	$1,944-5,219	4
Spray Dryer	95%	Oil	250	$13,300-188,820	2005	$1,841-4,945	4

Table 3-7 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet FGD	90%	High-S Coal	100	$81,939	1999		1
Wet FGD	90%	High-S Coal	250	$62,318	1999		1
Wet FGD	90%	High-S Coal	1000	$41,216	1999		1
Wet FGD	90%	Low-S Coal	100	$76,018	1999		1
Wet FGD	90%	Low-S Coal	250	$57,759	1999		1
Wet FGD	90%	Low-S Coal	1000	$38,122	1999		1
Wet FGD	90%	Coal	250	$11,507-172,672	2005	$2,089-3,822	4
Wet FGD	99%	Coal	250	$11,507-172,672	2005	$1,881-3,440	4
Wet FGD	90%	Oil	100	$69,848	1999		1
Wet FGD	90%	Oil	250	$53,066	1999		1
Wet FGD	90%	Oil	1000	$35,019	1999		1
Wet FGD	90%	Oil	250	$11,507-172,672	2005	$2,173-5,215	4
Wet FGD	99%	Oil	250	$11,507-172,672	2005	$1,956-4,694	4

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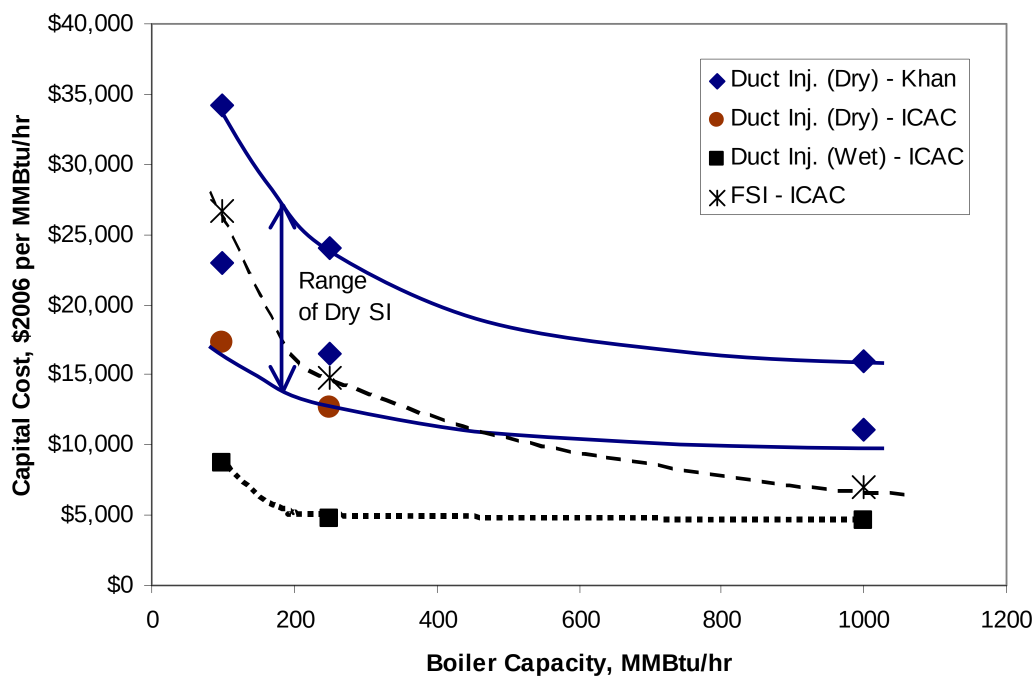

Figure 3-8. Capital cost for SO_2 control for dry sorbent injection applied to ICI boilers as a function of boiler capacity

Spray dryer (SD) technology has been widely applied to coal-fired EGUs. Estimates in the literature for SD technology for ICI boilers give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005]. *Figure 3-9* summarizes these capital costs for ICI boilers. Note that the MACTEC estimates at 250 MMBtu/hr boiler size assumed high and low equipment cost, but a detailed cost breakdown was not given.

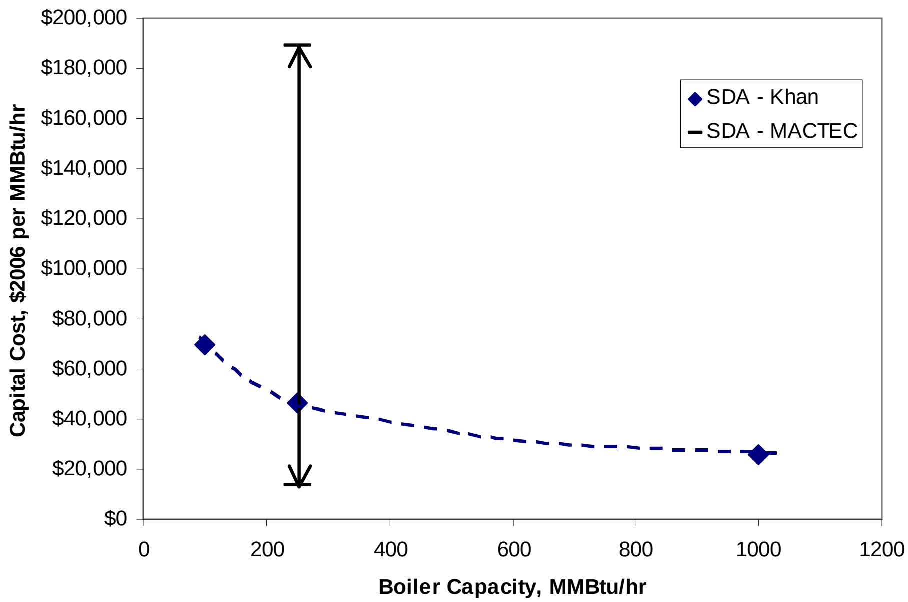

Figure 3-9. Capital cost for SO_2 control for Spray Dryer Absorber applied to ICI boilers as a function of boiler capacity

Wet FGD technology has been widely applied to coal-fired EGU boilers but rarely to ICI boilers, although at least one oil-fired installation has been noted in the literature [Caine and Shah, 2008]. The relationship between FGD capital cost and boiler capacity is shown in *Figure 3-10*. Estimates in the literature give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005], although these estimates are not always based on actual field installation data because installations of wet FGD technology on ICI boilers are few at present.

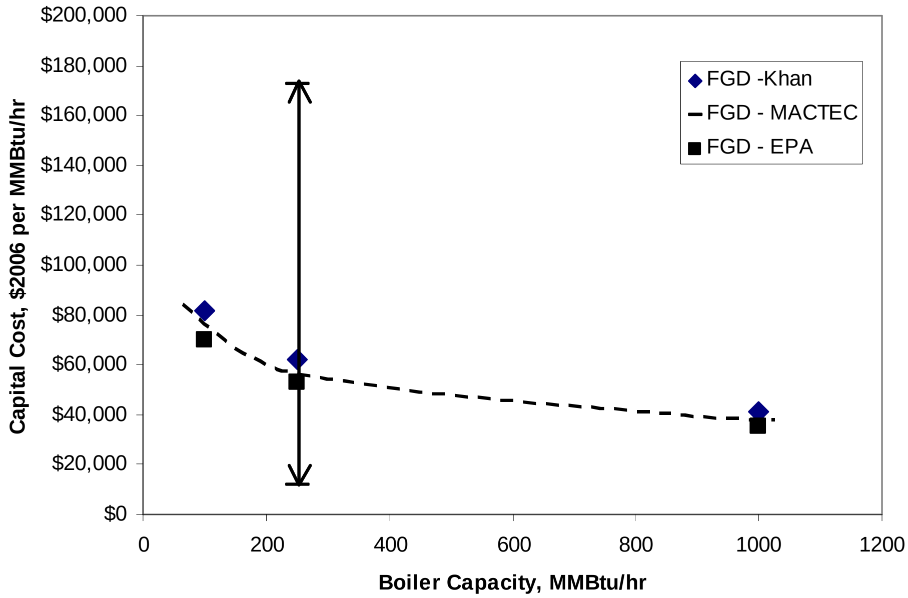

Figure 3-10. Capital cost for SO_2 control for wet FGD applied to ICI boilers as a function of boiler capacity

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4 PM CONTROL TECHNOLOGIES

4.1 PM Formation in Combustion Systems

PM emissions from combustion processes include primary and secondary emissions. Primary emissions consist mostly of fly ash. Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter (PM_{10} and $PM_{2.5}$). Fly ash refers to the mineral matter of the fuel, which typically includes some level of unburned carbon. ICI boilers burn a variety of fuels that contain ash and, as such, have PM emissions. Therefore, ICI boilers are candidates for PM controls.

Coal and oil contain non-combustible ash material. Other liquid or solid fuels (e.g., petroleum coke, wood) also contain ash. The quantity of ash in the flue gas depends on many factors, such as fuel properties, boiler design, and operating conditions. In dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash, and the remaining ash is collected as bottom ash. However, in wet-bottom, pulverized-coal-fired boilers, about 50 percent of the total ash exits the boiler as fly ash. In cyclone boilers (common in the EGU sector but not in the ICI population), most of the ash is retained as liquid slag, and the fly ash is only about 20 percent of the total ash. Fluidized-bed combustors (FBC) emit high levels of fly ash because the coal is fired in suspension and the ash is present in dry form. Stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers because combustion takes place in a relatively quiescent fuel bed.

In addition to the nitrates and sulfates mentioned as secondary PM, NOx control technologies that inject ammonia or amine-based reagents (SNCR and SCR) yield a certain amount of ammonia "slip," which can also form fine particulate (ammonium sulfate) as the flue gas temperatures decrease towards the stack.

This section presents a brief description of the major primary PM technologies.

4.2 PM Control Technologies

PM control technologies have been commercially available and widely used in ICI and EGU boilers for many years. *Table 4-1* summarizes the main types of commercially available technologies.

Table 4-1. Available PM control options for ICI boilers

Technology	Description	Applicability	Performance
Fabric filters (Baghouse)	"Baghouses" made of close-knit fabrics remove particulates through filtration.	Primarily used in coal/wood fired industrial/utility boilers. Not used with oil boilers due to clogging.	>99% total and $PM_{2.5}$ removal
ESPs (Dry/Wet)	Charged particles attracted to oppositely charged plates. Collection method either wet/dry.	Widely used in coal applications. Suitable for oil, pet coke and waste solid fuels. Wet ESPs suitable for saturated flue gas.	Effectiveness depends on resistivity of particulates. Low sulfur can reduce performance of dry ESP. >99% reduction of total PM (dry/wet) and sulfuric acid mist and $PM_{2.5}$ (wet)
Venturi Scrubbers	Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste.	High pressure required for significant removal. Applicable to a wide range of fuels.	50% removal for fine particulates, 99% removal for large (>5 micron) particulates
Cyclones	Cyclones use aerodynamic forces to separate particles from the gas stream.	Widely applicable to all fuels.	70%-90% total PM potential

4.3 Description of Control Technologies

4.3.1 Fabric Filters

Fabric filters (also called baghouses) are essentially giant vacuum cleaners and very effective devices for collecting dry PM from flue gas. They are used in ICI and EGU applications, although less widely than ESPs. Separation occurs when the ash-laden flue gas passes through a porous layer of filter material. As the individual particles accumulate on the surface of the filter, they gradually form a layer of ash known as the "dust cake." Once formed, the dust cake provides most of the filtration. However, they are not particularly well suited for wet gas applications due to the negative impact of wet gas on the bag filters. *Figure 4-1* shows a photograph of the internal components of a fabric filter compartment with several individual bags and mounting mechanisms.

Figure 4-1. Photograph of fabric filter compartment with filter bags [Source: www.hamon-researchcottrell.com]

As shown in *Figure 4-1*, multiple bags are assembled in compartments to provide a large surface area for filtration. The large surface area is required to maintain acceptable pressure loss across the fabric. Groups of bags are placed in compartments, which can be isolated from one another to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse.

Baghouse size is typically defined in terms of “air-to-cloth” ratio, expressed in the units of velocity in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The size of the baghouse depends on the particulate loading and characteristics, and the cleaning method used.

The type of bag cleaning method employed characterizes baghouses. Cleaning intensity and frequency are important because the dust cake provides a significant fraction of the fine particulate removal capability of a fabric. Hence, too frequent or too intense a cleaning method may lower the removal efficiency. Conversely, if removal of this dust cake happens infrequently or inefficiently, the pressure drop will increase to unacceptable levels. The major cleaning methods are as follows.

- Reverse-air baghouse – In this case, the flue gas flows upward through the vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken off-line, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers.
- Pulse-jet baghouse – In this case, the dust is collected on the outside of the bags, which are mounted on cages to keep them from collapsing. Dust is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, allowing it to be done on-line. Because pulse-jet cleaning is more intensive than in reverse-air baghouses, the bags in a pulse-jet baghouse remain relatively clean, resulting in the ability to use a higher air-to-cloth ratio or a smaller baghouse compared to the reverse-air type.

Additionally, fabric filters can also be used in applications where fly-ash resistivity makes it difficult for collection with ESPs. Further, baghouses are capable of 99.9 percent removal efficiencies, as well as being able to remove the smaller size PM fraction ($PM_{2.5}$) more efficiently.

4.3.2 Electrostatic Precipitators

ESP's operate on the principle of electrophoresis by imparting a charge to the particulates and collecting them on opposed charged surfaces. Dry vs. wet ESPs refer to whether the gas is water-cooled and saturated prior to entering the charged collection area or is dry. *Figure 4-2* and *Figure 4-3* show schematic views of dry and wet ESPs, respectively. Older ESPs are often of the wire-pipe design, in which the collecting surface consists of one or more tubes (operated wet or dry). The wire-plate design is the other commonly used ESP design, as illustrated in the schematic in *Figure 4-2*.

In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 µm on a mass basis with wet ESPs being capable of such reductions well into the sub-micron level (0.01 µm) [Altman, 2001].

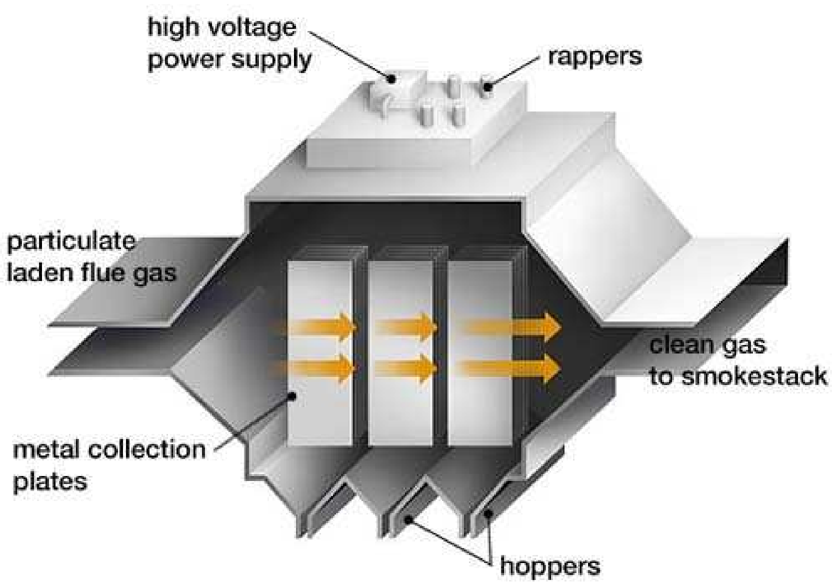

Figure 4-2. Side view of dry ESP schematic diagram [Source: Powerspan]

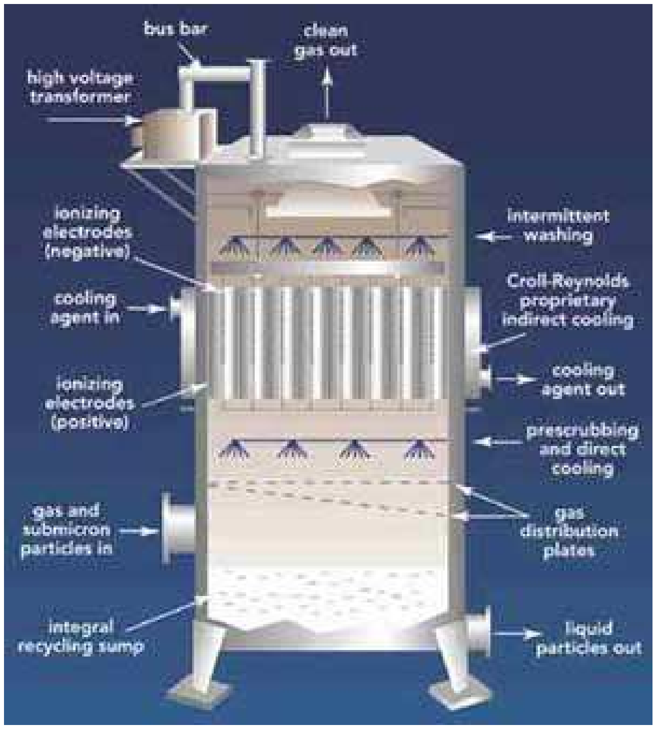

Figure 4-3. Wet ESP [Croll Reynolds]

Compared to fabric filters, ESPs affect the flue gas flow minimally, resulting in much lower pressure drops then an equivalent baghouse (typically less than two inches H_2O vs. greater than six inches H_2O for the fabric filter).

An electric field between high-voltage discharge electrodes and grounded collecting electrodes produces a corona discharge from the discharge electrodes, which ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The negatively charged particles are attracted to the collecting electrodes. To remove the collected fly ash, the collecting electrodes are rapped mechanically, causing the fly ash to fall into hoppers for removal.

A balance generally needs to be struck between higher voltages for higher particulate removal efficiency and excessive sparking which will have the opposite effect. Larger ESPs are sectionalized (see *Figure 4-2*) such that higher voltages can be used in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages are then used in the last, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. This has the added advantage that particles re-entrained in the flue gas stream by rapping (striking the electrode to dislodge the dust) may be collected in the downstream sections of the ESP.

Precipitator size is a major variable affecting overall performance or collection efficiency. Size determines residence time (the time a particle spends in the precipitator). Precipitator size also is typically defined in terms of the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher SCA leads to higher removal efficiencies. Collection areas can range from as low as 200 to as high as 800 ft^2/1000

acfm. In order to achieve collection efficiencies of 99.5 percent, SCA of 350-400 ft^2/1000 acfm is typically used. The overall (mass) collection efficiencies of ESPs can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies can achieve high efficiencies across a range of particle sizes so that good control of PM_{10} and $PM_{2.5}$ is possible with well designed and operated electrostatic precipitators.

Unlike dry ESPs, which use rapping to remove particulates from the collecting electrodes, wet ESPs use a water spray to remove the particulates. By continually wetting the collection surface, the collecting walls never build up a layer of particulate matter. This means that there is little or no deterioration of the electrical field due to resistivity, and power levels within a wet ESP can therefore be higher than in a dry ESP. The ability to inject greater electrical power within the wet ESP and elimination of secondary re-entrainment are the main reasons a wet ESP can collect sub-micron particulate more efficiently.

Overall, ESPs have historically been the collection device of choice for many applications in the ICI boiler and EGU boiler sectors. High removal efficiencies are possible and the units are rugged and relatively insensitive to operating upsets. Wet ESPs offer performance characteristics for capturing $PM_{2.5}$ similar to fabric filters and are well suited for applications such as oil firing, for which fabric filters are less attractive, because the sticky ash particles produced from oil combustion can blind the bags.

4.3.3 Venturi Scrubbers

Venturi scrubbers for PM control operate on the principle of rapid mixing and impingement of PM with liquid droplets and subsequent removal with the liquid waste. For particulate controls, the venturi scrubber is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressure drops are required. High-energy scrubbers operate at pressure losses of 50 to 70 inches of water. Higher pressure drop translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis. However, venturi scrubbers are seldom used as the primary PM collection device because of excessive pressure drop and associated energy penalties. *Figure 4-4* depicts a venturi scrubber.

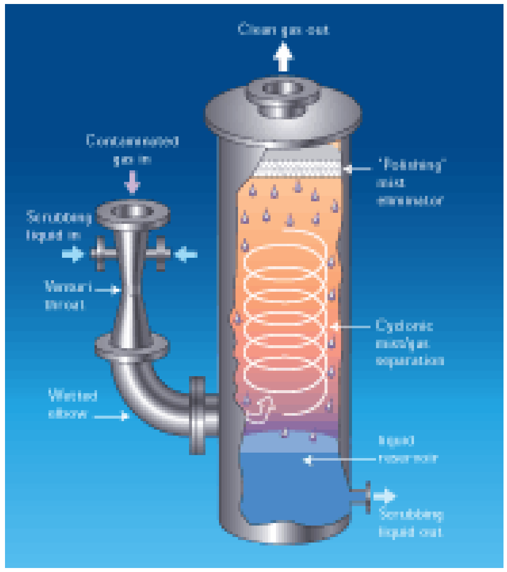

Figure 4-4. Venturi scrubber [Croll Reynolds]

4.3.4 Cyclones

Cyclones are devices that separate particulates from the gas stream through inertial forces. As ash-laden gas enters the cyclone near the top, a high-velocity vortex is created inside the device. Heavy particles move outward due to centrifugal force and begin accumulating on the wall of the cyclone. Gravity continuously forces these particles to move downward where they collect in the lower, hopper region of the cyclone. The collected particles eventually discharge through an opening in the bottom of the hopper into a system that transports the particles to a storage area. Smaller and lighter particles that remain suspended in the flue gas move toward the center of the vortex before being discharged through the clean-gas outlet located near the top of the cyclone (see *Figure 4-5*).

Cyclones are comparatively simple devices in design and construction, with no moving parts. Cyclones can operate over a wide range of temperatures, which makes them attractive for smaller ICI boilers that do not have economizers and/or air preheaters (and thus higher stack temperatures than in EGU boilers). Pressure drops across cyclones are typically in the range of 2 to 8 inches of water for a single cyclone. Cyclones can be arranged in arrays (multi-cyclones) and have overall mass removal efficiencies of 70 to 90 percent with the corresponding increase in pressure drop. However, cyclone collection efficiencies are very sensitive to particle size, and control efficiency for fine particulate ($PM_{2.5}$) is poor [Licht, 1988].

Cyclones are most effective at high boiler loads, where flue gas flow rates are highest. From an operational perspective, cyclones have no moving parts, are not sensitive to fuel quality or gas temperature, and require only regular cleaning to avoid plugging. These characteristics have made them good options in the past, particularly in the absence of regulatory $PM_{2.5}$ requirements.

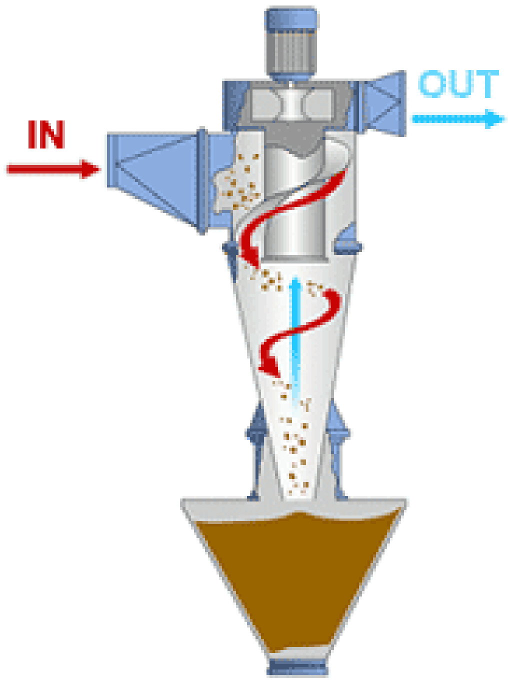

Figure 4-5. Schematic of a cyclone collector [www.dustcollectorexperts.com/cyclone]

Due to the limited potential for $PM_{2.5}$ capture, use of cyclones in new combustion applications is primarily limited to fluidized-bed boilers where they are used to re-circulate the bed material – and not as primary PM control devices.

4.3.5 Core Separator

The core separator is a mechanical device that operates based on aerodynamic separation (like cyclones), but also utilizes a "core separator." The separator portion of the device consists of multiple cylindrical tubes with one inlet and two outlets. One outlet allows for a clean gas stream to exit, while the other outlet is used for recirculating the concentrated stream. This recirculation stream then passes through the cyclone unit (see *Figure 4-6* [Resource Systems Group, 2001]), where it is further cleaned and returned to the separator. This sequential process enhances its overall control efficiency as compared to single or multiple cyclones.

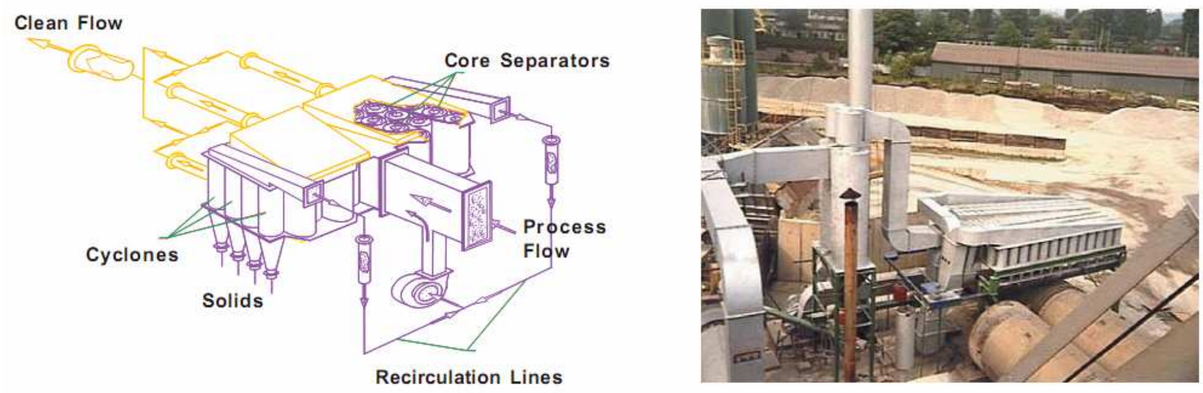

Figure 4-6. Schematic (left) and actual (right) core separator system [EPA, 2003]

The core separator capability for PM removal falls between that of an ESP and a cyclone. Several systems are currently installed on coal- and wood-fired boilers. The core separator unit is capable of overall PM reductions of up to the 90 percent range. Its collection efficiency, however, diminishes to about 50 percent for $PM_{2.5}$. *Table 4-2* displays inlet and outlet PM concentrations and removal efficiency of a core separator at two different plants. *Table 4-3* presents estimated costs for the core separator for two different sizes and gas flow conditions.

Table 4-2. Core separator collection efficiency [USEPA, 2008; Resource Systems Group, 2001]

Core Separator Inlet Loading (lb/million Btu)	Core Separator Outlet Loading (lb/million Btu)	Removal Efficiency	Boiler Type
0.17	0.07	59%	Wood Fired
0.846	0.214	75%	Stoker – Coal

Table 4-3. Core separator cost analysis [B. H. Eason to P. Amar, 2008]

Boiler Size	MMBtu/hr	8	10
	Estimated gas temperature (°F)	500	500
	Estimated gas flow rate (acfm)	4979	5996
Core Separator Size and Estimated Price (uninstalled)	Gas Flow per 12” module	660	660
	Number of 12” Modules	7	9
	Estimated price	$110,000	$130,000
	Gas Flow per 24” Module	2640	2640
	Number of 24” Modules	1	2
	Estimated Price	$55,000	$83,000

4.4 Applicability of PM Control Technologies to ICI Boilers

The PM control technologies described in this section are widely available and are used in both ICI and EGU applications. Because all these PM controls are based on the collection of particulates from the flue gas, they are applicable to a variety of boiler types and ash-containing

fuels, including coal, oil, wood, petroleum coke, and other waste fuels. Determining the most attractive option for individual applications is a case-by-case decision that needs to account for technical, economic, and regulatory considerations. One exception, as mentioned, is that fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash.

4.5 Efficiency Impacts

PM control technologies do result in some parasitic energy loss as can be deduced from the brief descriptions of technologies above (see *Table 4-1*). The inherent energy losses associated with each technology are given below and summarized in *Table 4-4*.

- For Fabric Filters
  - compressor (bag cleaning)
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For ESPs
  - transformer-rectifier (TR) power
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For Venturi Scrubber and Cyclone
  - flue gas pressure loss

Table 4-4. Summary of energy impacts for control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)	Comments
Fabric Filter	Coal, Wood	99+	1 – 2	Pressure loss / compressor / ash handling
Dry ESP	Coal, Oil, Wood	99	0.5 – 1.5	Pressure loss / TR power / ash handling
Wet ESP	Coal, Oil, Wood	99+	3 - 6	Pressure loss / TR power / ash handling
Venturi Scrubber	Coal, Oil, Wood	70-90 (Not efficient for $PM_{2.5}$)	5 - 11	Pressure loss
Cyclone	Coal, Wood	70-90 (Not efficient for $PM_{2.5}$)	0.5 – 1.5	Pressure loss

4.6 PM Control Costs

The following tables summarize published PM control costs for ICI boilers reported in the literature [US EPA, 2003a; US EPA, 2003b; US EPA, 2003c; US EPA, 2003d; US EPA, 2003e; US EPA, 2003f; MACTEC, 2005]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness

in dollars per ton of PM removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some of the operating costs, but these items do not always increase with the rate of inflation for chemical plant equipment. Thus, cost effectiveness values (or operating costs) from years before 2005 have not been reported.

Table 4-5 summarizes the published PM control costs for several different PM control technologies. In the EPA references, the capital costs were given in terms of dollars/scfm (2002 dollars). These costs were converted to dollars per MMBtu/hr using the flow rates given in Chapter Five and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values.

The MACTEC capital costs [MACTEC, 2005] span a large range, because high and low estimates for capital equipment were used in the calculation. The EPA capital costs are much higher for the wire-pipe ESP (also known as a tubular ESP) than the wire-plate ESP. Note that a size was not given in the EPA cost estimate, so a range is shown. The capital cost comparison is similar for wet ESPs although the capital costs themselves (in dollars/MMBtu/hr) are higher for wet ESPs as compared to dry ESPs.

For fabric filters, pulse-jet and reverse-air fabric filters were considered. These types of equipment have similar collection efficiencies, but the capital costs and effectiveness of pulse-jet fabric filters are lower than that of reverse-air fabric filters.

Table 4-5. PM control costs applied to ICI boilers

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu /hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Dry ESP	90%	Coal	250	$12,365-$160,754	2005	$171-$1,300	7
Dry ESP	99%	Coal	250	$12,365-$160,754	2005	$156-$1,172	7
Dry ESP	90%	Oil	250	$6,713-$87,275	2005	$2,584-$21,009	7
Dry ESP	99%	Oil	250	$6,713-$87,275	2005	$2,328-$18,912	7
Dry ESP (Wire-Pipe)		Coal	--	$6,571-$41,070	2002		1
Dry ESP (Wire-Plate)	90%-99%	Coal	--	$3,286-$10,843	2002		2
Dry ESP (Wire-Pipe)		Resid.Oil	--	$5,198-$32,486	2002		1
Dry ESP (Wire-Plate)	90%-99%	Resid.Oil	--	$2,599-$8,576	2002		2
Dry ESP (Wire-Pipe)		Dist.Oil	--	$5,117-$31,983	2002		1
Dry ESP (Wire-Plate)	90%-99%	Dist.Oil	--	$2,559-$8,443	2002		2
Dry ESP (Wire-Pipe)		Wood	--	$7,560-$47,249	2002		1
Dry ESP (Wire-Plate)	90%-99%	Wood	--	$3,780-$12,474	2002		2
ESP	99.50%	Wood	Small	--	2005	$594	8
ESP	99.50%	Wood	Medium	--	2005	$203-$292	8
ESP	99.50%	Wood	Large	--	2005	$114-130	8
Fabric Filter	90%	Coal	250	$7,453-$93,158	2005	$444-$1,006	7
Fabric Filter	99%	Coal	250	$7,453-$93,158	2005	$423-$957	7
Pulse-Jet Fabric Filter	95%-99.9%	Coal	--	$1,971-$8,543	2002		5
Reverse-Air FF	95%-99.9%	Coal	--	$3,286-$28,585	2002		6
Fabric Filter	90%	Oil	250	$4,046-$50,577	2005	$7,277-$16,464	7
Fabric Filter	99%	Oil	250	$4,046-$50,577	2005	$6,915-$15,643	7
Pulse-Jet Fabric Filter	95%-99.9%	Resid.Oil	--	$1,559-$6,757	2002		5
Reverse-Air FF	95%-99.9%	Resid.Oil	--	$2,559-$22,260	2002		6
Pulse-Jet Fabric Filter	95%-99.9%	Dist.Oil	--	$1,535-$6,652	2002		5
Reverse-Air FF	95%-99.9%	Dist.Oil	--	$2,599-$22,610	2002		6
Fabric Filter	99.50%	Wood	Small	--	2005	$958	8
Fabric Filter	99.50%	Wood	Medium	--	2005	$147-249	8
Fabric Filter	99.50%	Wood	Large	--	2005	$91-$107	8
Pulse-Jet Fabric Filter	95%-99.9%	Wood	--	$2,268-$9,829	2002		5
Reverse-Air FF	95%-99.9%	Wood	--	$3,780-$32,886	2002		6

Table 4-5 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet ESP	90%	Coal	250	$25,968-$252,260	2005	$906-$2,627	7
Wet ESP	99.9%	Coal	250	$25,968-$252,260	2005	$815-2,365	7
Wet ESP (Wire-Pipe)	90%-99.9%	Coal	--	$13,142-$65,712	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Coal	--	$6,571-$13,142	2002		4
Wet ESP	90%	Oil	250	$14,098-$136,955	2005	$14,938-$43,036	7
Wet ESP	99.9%	Oil	250	$14,098-$136,955	2005	$13,446-$38,736	7
Wet ESP (Wire-Pipe)	90%-99.9%	Resid.Oil	--	$10,395-$51,977	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Resid.Oil	--	$5,198-$10,395	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Dist.Oil	--	$10,235-$51,172	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Dist.Oil	--	$5,117-$10,234	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Wood	--	$15,120-$75,599	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Wood	--	$7,560-$15,120	2002		4

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5 APPLICATION OF A COST MODEL TO ICI BOILERS

When evaluating the applicability of pollution control equipment to a specific ICI boiler, cost and performance capability need to be considered. A number of cost estimation models have been created for estimation of capital and operating costs of retrofit technology for air pollutants. However, most of the cost models have been developed for and applied to EGUs burning coal. Much less work has been carried out on cost estimation models for ICI boilers. In this Chapter, a cost modeling approach currently used for estimating control costs for coal-burning EGUs is modified and then investigated for its applicability to ICI boilers burning coal as well as other fuels. The purpose of this Chapter is to present this modified cost model (CUECost-ICI) and resulting cost calculations. The strengths and weaknesses of this approach are also discussed. However, the purpose of this effort is not to carry out an exhaustive calculation of costs, but to generate a set of reasonable cost estimates for ICI boilers burning different fuels and compare them with published cost information.

5.1 Cost Model Inputs and Assumptions

The Coal Utility Environmental Cost (CUECost) model was developed by Raytheon Engineers for EPA; version 3, and is available on EPA's website at http://www.epa.gov/ttn/catc/products.html. The model calculates capital and operating costs for certain predefined air pollution control devices for control of NOx, SO_2, and PM as applied to coal-fired power plants. The CUECost model produces approximate cost estimates (±30 percent accuracy) of the installed capital and annualized operating costs. The CUECost model was originally designed for and is intended for use on coal-fired boilers greater in size than 100 MW (about 1,000 MMBtu/hr heat input).

Table 5-1 gives the general plant inputs that are needed to set up the model; more inputs are needed for specific air pollution control devices (see Appendix B).

Table 5-1. CUECost general plant inputs

Input Parameter	*Comment*
Location - State	
MW Equivalent of Flue Gas to Control System	*This was designed for EGUs, but can be scaled to generate the appropriate gas flow for ICIs*
Net Plant Heat Rate	*Function of the efficiency of the plant*
Plant Capacity Factor	*Use averages from EEA study, parametric variations*
Percent Excess Air in Boiler	*Assume 3% O_2 for NG and oil, 7% O_2 for coal, wood*
Air Heater In-leakage	*Determines the flow rate for downstream devices such as scrubbers and particulate control devices*
Air Heater Outlet Gas Temperature	
Inlet Air Temperature	
Ambient Absolute Pressure	
Pressure After Air Heater	
Moisture in Air	
Ash Split:	*Depends on firing system*
Fly Ash	
Bottom Ash	
Seismic Zone	
Retrofit Factor	*Moderate effect on total capital requirement (TCR)*
(1.0 = new, 1.3 = medium, 1.6 = difficult)	
Select Fuel	*User can define "coal" with respect to HHV, %S, %ash*

The EPA version of CUECost contains the following modules for specific air pollution control devices:

- Limestone forced-oxidation, wet FGD scrubber
- Lime spray dryer
- FF
- ESP
- SCR
- SNCR
- LNB
- Natural Gas Reburn

CUECost bases the costs of equipment and operation on the generating capacity (in MW of electricity generated) of a given boiler. Industrial boilers are usually rated by the heat input (in MMBtu/hr); the boiler heat rate is used to convert from heat input to the equivalent size in MW. In order to use CUECost in its present form for ICI boilers, an equivalent size in MW needs to be estimated, although this could be modified in a dedicated ICI boiler version of CUECost (which was not developed in this effort).

Industrial boilers are operated differently from utility boilers, and the inputs for CUECost-ICI must be adjusted accordingly, including:

- Heat rate
- Excess air level

- Flue gas temperatures
- Capacity factor

The default values in the current version of CUECost for EGUs generally do not describe ICI boilers well. Fuel compositions vary widely for ICI boilers, while the EGU version of CUECost includes coal as the only fuel option (with different compositions). However, the user can define other fuels, as described below.

An important factor in determining total installed capital cost is the choice of appropriate retrofit factor, which expresses the difficulty of installing a control technology in an existing plant. In CUECost a retrofit factor of 1.0 denotes a new plant (corresponding to the lowest capital cost), and retrofit factors of 1.3 and 1.6 denote medium and difficult retrofits, respectively. Emmel [2006] noted that this range of retrofit factors significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs less than 100 MW. Emmel also noted that on average a retrofit factor of 1.45 was more reasonable and that the factor should be even higher when CUECost is applied to ICI boilers.

The technology options in CUECost are also fixed, and the user cannot create a new technology option without supplying formulae for calculating the capital equipment cost. The technology options for SO_2 control in CUECost, in particular, have been noted to be more appropriate for larger utility boilers than for ICI boilers. Wet FGD and spray dryer technology – the SO_2 scrubbing options in CUECost – are based on lime or limestone reagents and have high capital and operating costs compared to alkaline scrubbers or duct injection. The latter scrubbing options might be more attractive for ICI boilers, but would have to be added to the current version of CUECost.

Finally, Emmel [2006] notes that most ICI boiler sites will have higher contingency, general facility, engineering, and maintenance costs (on a percentage of capital cost basis) than those identified for EGUs in CUECost in order to take into account necessary upgrades or demolition of existing facilities that are less likely to be needed at sites.

In this effort, the CUECost model was adapted for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. Capital and operating costs in the model were based on correlations derived from coal-fired power plant experience since no reliable field data were available for the ICI boilers. It is not clear how robust the correlations for capital equipment are for small (≤ 25 MW equivalent) boilers.

The CUECost model is based on the electrical generating capacity. A combustion calculation was used to relate heat input rate to equivalent MW for five different fuels.

Table 5-2 gives the properties of these fuels. Boiler efficiency was specified, and heat rate was calculated from boiler efficiency. The uncontrolled or baseline emissions were based on fuel composition (in the case of SO_2 and PM) or on industry operating experience (in the case of NOx).

Table 5-3 shows the results (in terms of calculated flue gas flow rates) of the combustion calculations for a fixed heat input rate of 250 MMBtu/hr or 100 MMBtu/hr. Flue gas flow rate is an important parameter or input to the cost model, because the size of capital equipment is often related to the flue gas flow rate.

Table 5-2. Fuel characteristics and assumptions for CUECost calculation of heat rate and flue gas flow rates

	Bituminous	Wood	No.2 Oil	No.6 Oil	Gas
C, wt%	76.2	27.6	86.4	85.8	75
S, wt%	2.5	0.04	0.6	2.5	0
H, wt%	4.6	3.3	12.7	10.6	25
Moisture, wt%	1.4	45	0.02	0.02	0
N, wt%	1.4	0.3	0.1	0.5	0
O, wt%	7	22.86	0.1	0.5	0
Ash, wt%	6.9	0.9	0.08	0.08	0
Fuel heating value, BTU/lb	13,630	4,633	19,563	18,273	20,800
Unburned carbon, wt% in ash	5	1	75	75	0
Boiler efficiency*	34%	30%	39%	39%	45%
Stack O_2, vol% dry	7%	7%	3%	3%	3%
Boiler heat rate, Btu/kWh	10,000	11,370	8,750	8,750	7,600
Uncontrolled or Baseline emissions NOx, lb NO_2/MMBtu	0.60	0.26	0.20	0.40	0.40
SO_2, lb/MMBtu	3.67	0.17	0.61	2.74	0.00
PM, lb/MMBtu	5.06	1.94	0.04	0.04	0.00

*Fuel to MW

Table 5-3. Equivalent heat input rate and flue gas flow rates for 250 and 100 MMBtu/hr heat input rates

	MW	MMBtu/hr	Flue gas, scfm
Bituminous coal (34% efficiency, 7% O_2)	25.0	250	65,305
Wood (30% efficiency, 7% O_2)	22.0	250	81,184
No.2 oil (39% efficiency, 3% O_2)	28.6	250	50,622
No.6 oil (39% efficiency, 3% O_2)	28.6	250	51,117
Natural gas (45% efficiency, 3% O_2)	32.9	250	59,336
Bituminous coal (34% efficiency, 7% O_2)	10.0	100	26,122
Wood (30% efficiency, 7% O_2)	8.8	100	32,474
No.2 oil (39% efficiency, 3% O_2)	11.4	100	20,178
No.6 oil (39% efficiency, 3% O_2)	11.4	100	20,375
Natural gas (45% efficiency, 3% O_2)	13.2	100	23,806

5.2 Comparison of the Cost Model Results with Literature

A comparison was made of the CUECost-ICI model with other published information for a selection of fuels and air pollution control devices applied to ICI boilers. Where possible, the inputs for the model were set to be the same as information cited in the literature.

Using the appropriate fuel composition and boiler heat rates, the modified ICI version of the original CUECost (CUECost-ICI) model was run for a number of ICI boiler cases. *Table 5-4*, *Table 5-5*, and *Table 5-6* show the installed capital costs, first-year annual operating costs, and cost per ton of pollutant removed for NOx, SO_2, and PM, respectively. Capital and operating costs were calculated on 2006 dollars basis in the CUECost-ICI model. A complete

list of inputs to CUECost-ICI is included in Appendix B. For the NOx and SO_2 control technologies, percentage reduction of the pollutant was used as an input, so that the CUECost-ICI results could be easily compared to published literature results. For PM controls, a specific emission limit (in lb/MMBtu) was used as an input and the percentage PM reduction was calculated from the fuel ash content.

Table 5-4. Capital and operating costs for NOx control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost/ton
250	80.0%	Coal	SCR	Ammonia	$4.394	$1.253	$4,763
100	80.0%	Coal	SCR	Ammonia	$2.585	$0.702	$6,668
250	80.0%	No.6 Oil	SCR	Ammonia	$2.923	$0.790	$3,972
100	80.0%	No.6 Oil	SCR	Ammonia	$1.760	$0.460	$5,805
250	80.0%	Nat.Gas	SCR	Ammonia	$3.005	$0.811	$4,673
100	80.0%	Nat.Gas	SCR	Ammonia	$1.805	$0.472	$6,777
250	50.0%	Coal	SNCR	Ammonia	$1.142	$0.398	$2,422
100	50.0%	Coal	SNCR	Ammonia	$0.969	$0.317	$4,817
250	50.0%	No.6 Oil	SNCR	Ammonia	$0.724	$0.338	$2,722
100	50.0%	No.6 Oil	SNCR	Ammonia	$0.407	$0.196	$3,961
250	50.0%	Nat.Gas	SNCR	Ammonia	$0.785	$0.362	$3,335
100	50.0%	Nat.Gas	SNCR	Ammonia	$0.443	$0.209	$4,798
250	40.0%	Coal	LNB	--	$1.227	$0.301	$2,290
100	40.0%	Coal	LNB	--	$0.677	$0.166	$3,155
250	40.0%	No.6 Oil	LNB	--	$1.339	$0.329	$3,305
100	40.0%	No.6 Oil	LNB	--	$0.737	$0.181	$4,559
250	40.0%	Nat.Gas	LNB	--	$1.467	$0.360	$4,151
100	40.0%	Nat.Gas	LNB	--	$0.810	$0.199	$5,715

Table 5-5. Capital and operating costs for SO_2 control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	95%	Coal	wFGD	Limestone	$38.096	$11.137	$4,427
100	95%	Coal	wFGD	Limestone	$33.680	$9.608	$9,547
250	95%	No.6 Oil	wFGD	Limestone	$36.642	$10.733	$5,713
100	95%	No.6 Oil	wFGD	Limestone	$32.805	$9.368	$12,510
250	90%	Coal	SD	Lime	$29.598	$8.806	$3,694
100	90%	Coal	SD	Lime	$26.263	$7.540	$7,909
250	90%	No.6 Oil	SD	Lime	$28.463	$8.371	$4,704
100	90%	No.6 Oil	SD	Lime	$25.723	$7.344	$10,352

Table 5-6. Capital and operating costs for PM control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	PM Emission, lb/MMBtu	Installed Capital Cost, $M	Capital cost, $/scfm	Capital cost, $/acfm	Annua l Cost, $M	Cost Effective ness (dollars per ton)
250	99.3%	Coal	ESP	0.03	$4.05	$62.00	$43.00	$1.11	$342
100	99.3%	Coal	ESP	0.03	$2.31	$88.50	$61.50	$0.63	$485
250	99.3%	Coal	FF	0.03	$4.77	$73.00	$50.70	$1.32	$406
100	99.3%	Coal	FF	0.03	$2.88	$110.20	$76.60	$0.78	$592
250	95.8%	No.6 Oil	ESP	0.01	$3.40	$66.60	$46.30	$0.93	$5,689
100	95.8%	No.6 Oil	ESP	0.01	$2.02	$99.00	$68.80	$0.55	$8,410
250	95.8%	No.6 Oil	FF	0.01	$4.09	$80.00	$55.60	$1.14	$6,940
100	95.8%	No.6 Oil	FF	0.01	$2.50	$122.80	$85.30	$0.68	$10,354

For comparison, the American Forest & Paper Association (AF&PA) calculated SNCR control costs in 2006 for wood-fired boilers ranging in size from 88 to 265 MMBtu/hr [Hunt, 2006]. *Table 5-7* below compares the AF&PA costs with the CUECost-ICI costs for wood-fired boilers. The installed capital cost values agree well between CUECost-ICI and the AF&PA estimates, although the CUECost-ICI values for cost effectiveness (dollars per ton of NOx removed) are 20 to 25 percent lower than the AF&PA estimates.

Table 5-7. Capital and operating costs for SNCR on wood-fired boilers, comparison of cost calculations from AF&PA and CUECost

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost, $/ton
AF&PA							
88.5	70.0%	Wood	SNCR	Urea	$0.924	$0.250	$11,283
176.9	70.0%	Wood	SNCR	Urea	$1.400	$0.384	$8,574
285.4	70.0%	Wood	SNCR	Urea	$1.786	$0.502	$7,480
CUECost							
88.5	70.0%	Wood	SNCR	Urea	$0.923	$0.289	$9,239
176.9	70.0%	Wood	SNCR	Urea	$1.025	$0.324	$5,174
285.4	70.0%	Wood	SNCR	Urea	$1.130	$0.361	$5,011

Finally, the CUECost-ICI model results for capital cost were compared with some of the values reported in the literature [US EPA, 1996; NESCAUM, 2000; US EPA, 2003a; US EPA, 2003b; Whiteman, 2006], where available. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using Chemical Engineering Plant Cost Index values.

The NOx capital costs computed with CUECost-ICI were largely consistent with the literature values. (Chapter Two contains a detailed discussion of the literature values for NOx control costs.)

Figure 5-1 compares capital costs for SCR for boilers burning coal, residual (No. 6) oil, and natural gas. The SCR costs appear to be consistent with the literature values. The literature value for SCR as reported by the Ozone Transport Assessment Group (OTAG) [US EPA, 1996] did not describe its basis in any detail, so it is difficult to determine if the OTAG cost estimates assumed a significantly different space velocity or different equipment than assumed in the CUECost-ICI model.

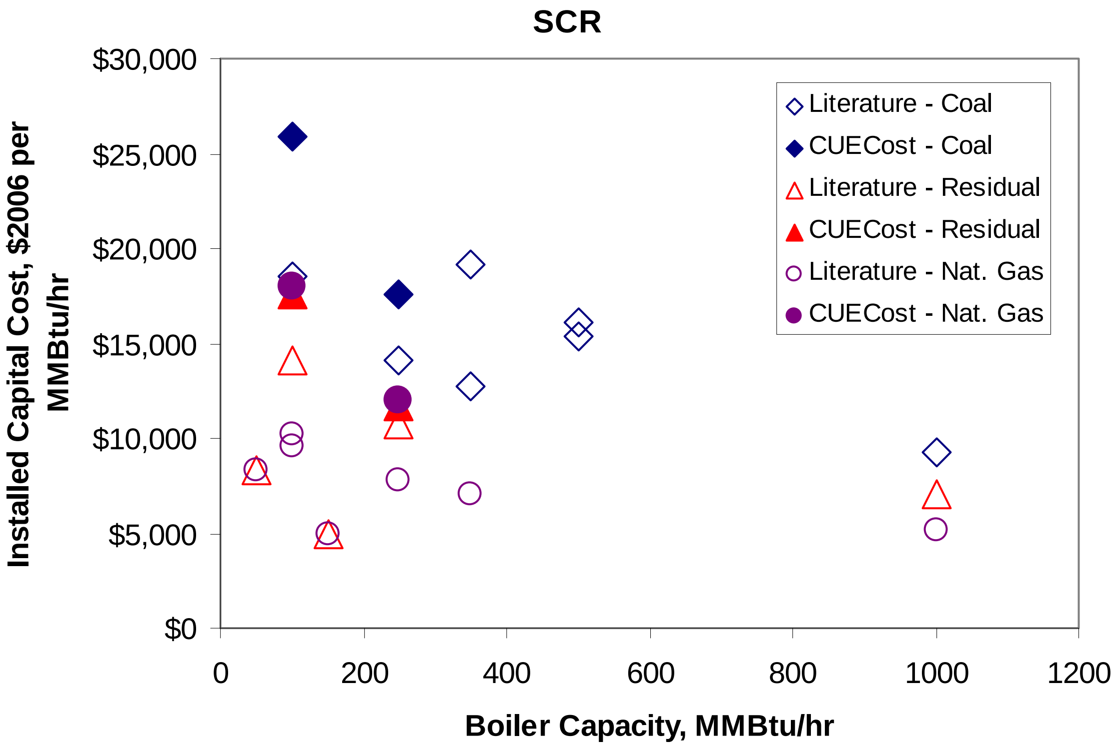

Figure 5-1. Comparison of CUECost-ICI model and reported literature values for capital cost of SCR for NOx control

The capital costs for SNCR (*Figure 5-2*) calculated from the CUECost-ICI model are in good agreement with literature values, particularly the sensitivity of capital cost to boiler capacity, which was also noted by ICAC [Whiteman, 2006].

The capital costs for LNB (*Figure 5-3*) calculated from the CUECost-ICI model for coal-fired boilers were consistent with the literature values, although the capital costs for residual oil-fired boilers were higher in the CUECost-ICI model than the literature values. Again, no details were provided in the literature references.

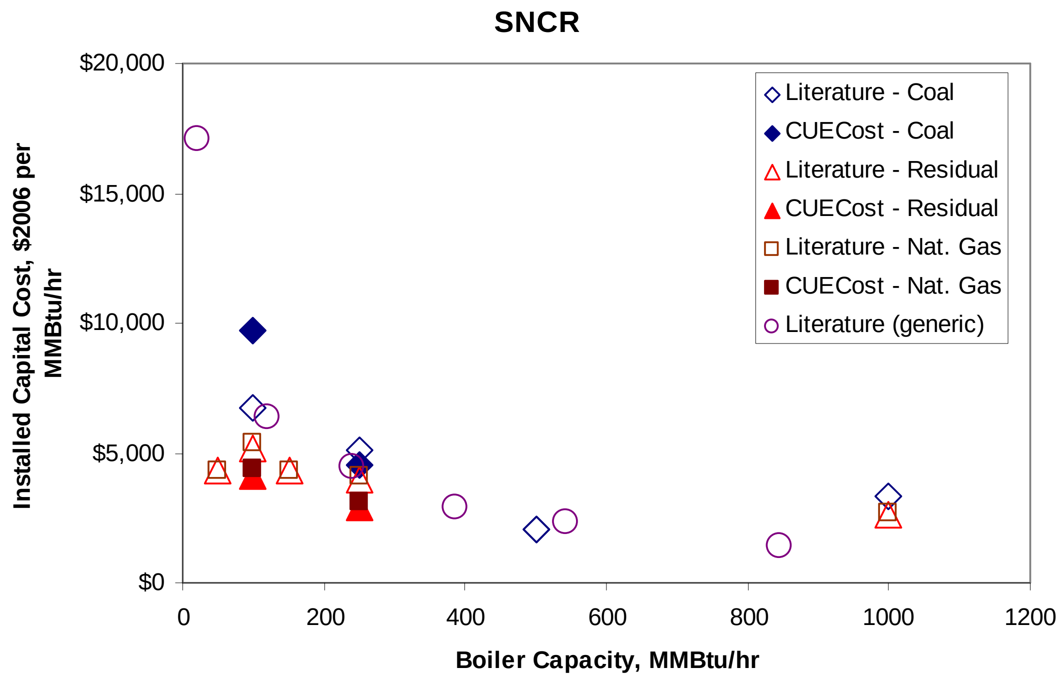

Figure 5-2. Comparison of CUECost-ICI model and reported literature values for capital cost of SNCR for NOx control

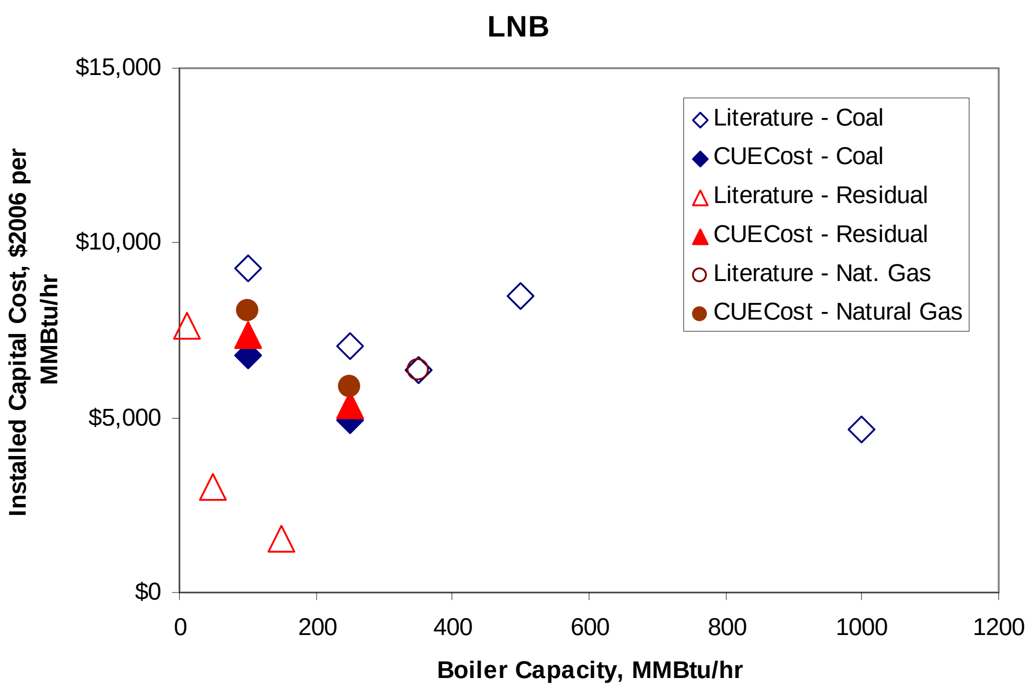

Figure 5-3. Comparison of CUECost-ICI model and reported literature values for capital cost of LNB for NOx control

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs. The SO_2 capital costs computed with CUECost-ICI for spray dryers (SDs) were in the range of the literature values at boiler size of 250 MMBtu/hr (*Figure 5-4*). No literature data were available for residual oil-fired boilers and spray dryers. However, the capital costs calculated by CUECost –ICI for wet FGDs (*Figure 5-5*) were high when compared to the literature values.

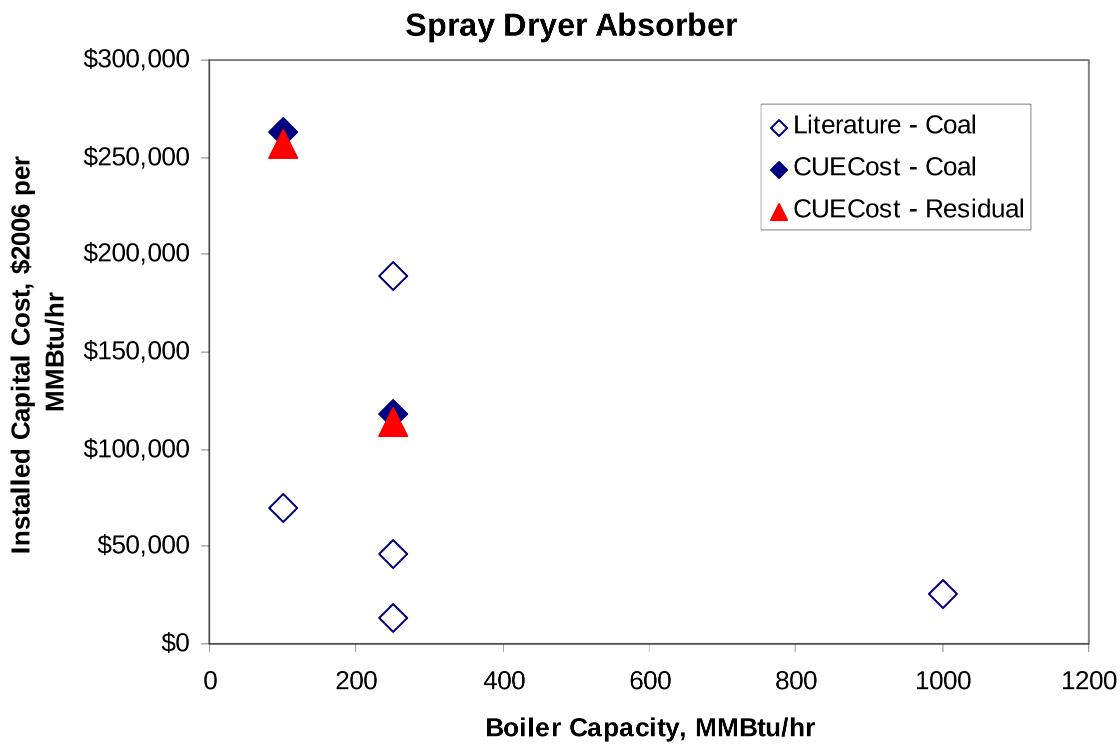

Figure 5-4. Comparison of CUECost-ICI model and reported literature values for capital cost of Spray Dryer for SO_2 control

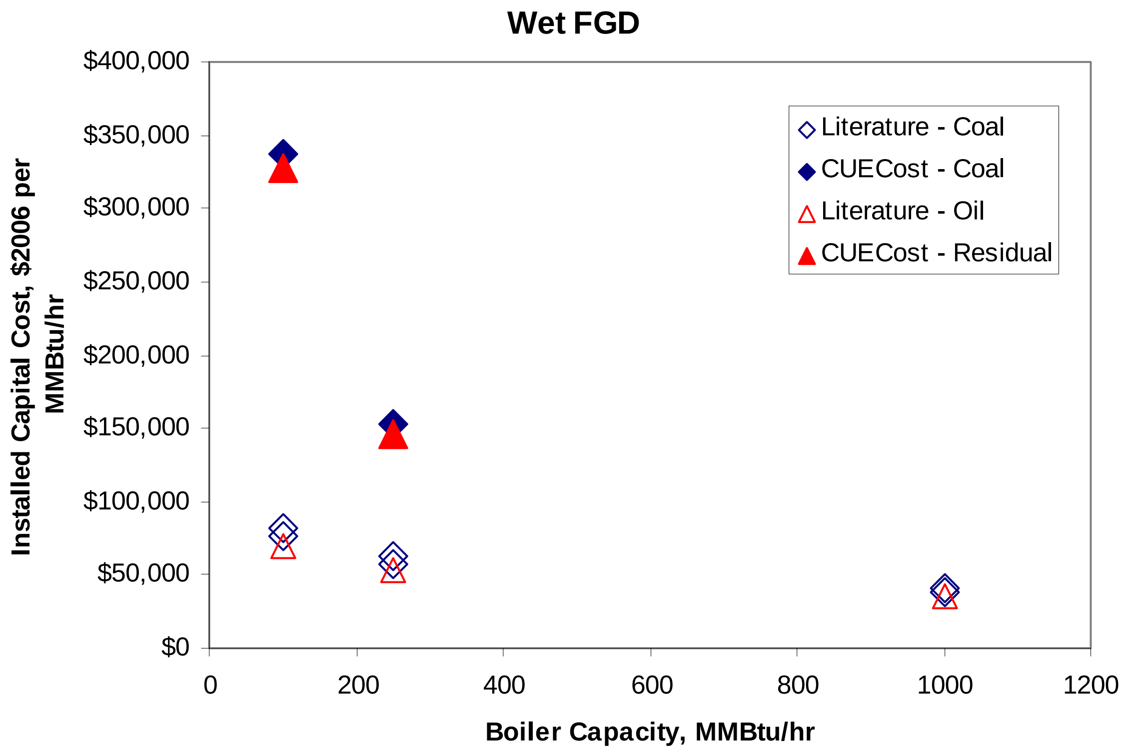

Figure 5-5. Comparison of CUECost-ICI model and reported literature values for capital cost of wet FGD for SO_2 control

Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to ICI boilers [US EPA, 2003a; US EPA, 2003b]. In these references, the capital costs were given in terms of dollars/scfm (2002$). These costs were converted to dollars per MMBtu/hr using the flow rates in *Table 5-3* and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values. Chapter Four contains a detailed discussion of the literature values for PM control costs.

The dry ESP control costs computed with CUECost-ICI were consistent with the literature values, although the CUECost-ICI predicted slightly higher values than reported by EPA for dry, wire-plate ESPs [US EPA, 2003a]. Note that a size was not given in the EPA cost-estimate. The FF costs computed with CUECost-ICI were higher than the literature values for pulse-jet fabric filters [US EPA 2003b].

5.3 Summary

An existing EPA model for estimating costs of selected control technology for NOx, SO_2, and PM for coal-fired EGU boilers greater than 1,000 MMBtu/hr was adapted for ICI boilers. Inputs were modified to allow a wider variety of fuels and to express boiler capacity in MMBtu/hr instead of MW. Modification of the correlations used for the coal-fired EGU model to calculate capital and operating costs for ICI boilers was outside the scope of this work. The new model, CUECost-ICI provided good agreement with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers. The resulting model provided a quick and flexible means to estimate capital and operating costs of

specific control technologies as applied to ICI boilers. Further detailed and extensive work will be needed to validate and refine the model's calculation framework for ICI boilers, and to add other APCD technologies to the model.

5.4 Chapter 5 References

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6 SUMMARY

ICI boilers are a significant source of NO_x, SO_2, and PM emissions, and are relatively uncontrolled, compared to EGUs. More than half of the surveyed ICI boilers in the Northeast have no controls, approximately one-third have PM controls, very few units have NOx controls, and no units have SO_2 controls.

There are a range of technology options for cost-effectively reducing emissions of NOx, SO_2, and PM emissions from ICI boilers in the U.S. Operating costs may differ for ICI boilers than utility boilers, primarily because of their size and location. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs as a percentage of total capital cost than do utility boilers. While ICI boilers often have cost constraints due to their sizes and diversity of plant layout and settings, these factors also provide opportunities for low-cost applications. It is critical to conduct site-specific suitability analyses to assess performance potential or retrofit feasibility, and match the appropriate emission control technology for specific applications given boiler size, fuel type/quality, duty-cycle, and design characteristics.

This study adapted the CUECost model -- initially developed by EPA to estimate costs of selected control technology for NOx, SO_2, and PM for large coal-fired EGU boilers -- to assess ICI boiler control costs. The modeling results were consistent with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers.

6.1 NOx Controls

Most of the commercially available NOx control technologies used extensively in EGUs may also apply to ICI boilers. Some technologies have potential to capture mercury from the flue gas. Employing a combination of technologies can be more effective in reducing emissions than a stand-alone technology. While most of these technologies can be used together, some combinations may be more cost-effective. This should be assessed on a site- and strategy-specific basis. Options include:

- *Boiler Tuning or Optimization*, which can yield reductions of five to 15 percent or more;
- *Low-NOx Burner (LNB) and Overfire Air (OFA)*, which can be used separately or as a system, and can reduce NOx emissions by 40 to 60 percent. LNBs are applicable to most ICI boiler types, and are being increasingly used at ICI boilers less than 10 MMBtu/hr. These technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility.
- *Ultra Low-NOx Burners (ULNB)*, which can achieve NOx emission levels on the order of single digits in ppm.
- *Reburn*, which has been used only in large EGU applications, but is an option for larger watertube-type boilers, including stokers. It requires appropriate technical and economic analyses to determine suitability. Reburn may yield 35 to 60 percent reductions in NOx emissions.
- *Selective Catalytic Reduction (SCR)*, which can achieve reductions higher than 90 percent.

- *Selective Non-Catalytic Reduction* (*SNCR)*, which can achieve between a 30 to 60 percent reduction in NOx.
- *Regenerative Selective Catalytic Reduction (RSCR^{TM})*, which is able to reduce NOx by 60 to 75 percent and CO by about 50 percent. These systems allow efficient use of an SCR downstream of a particulate control device, where the flue gas typically has a lower temperature than what is required for a conventional SCR. Such conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the exception of reburn. SNCR and SCR impose some degree of energy demand on the host boiler, including pressure, compressor, vaporization, and steam losses.

Most estimates for ICI boilers indicate capital costs in the range of $1,000 to $6,000 per MMBtu/hr and $1,000 to $7,000 per ton of NOx removed. LNBs and SNCR costs range from $1,000 to $3,000 per ton. For SCR, costs are between $2,000 and $14,000 per ton. SCR and SNCR costs are driven primarily by the consumption of the chemical reagent.

6.2 SO_2 Controls

ICI boilers firing coal are good candidates for employing SO_2 control technologies. Options include:

- *Flue Gas Desulfurization (FGD) or Scrubbers.* These technologies are commercially available, and have been used extensively on EGUs since the 1970s. *Wet scrubbers* (Wet FGD) are the predominant SO_2 control technology currently in use for EGUs, and are typically associated with high-sulfur applications. *Dry scrubbers* include Spray Dryers (SD) and Dry Sorbent Injection (DSI) technologies, and are more compatible with low- to medium-sulfur coals. Some dry scrubber systems can remove 20 to 60 percent of the SO_2, and in some cases up to 90 to 99 percent for HCl and SO_3. DSI technologies are currently being demonstrated on ICI boilers. Furnace Sorbent Injection systems used on cement plants are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent. For SDs, cost per ton of SO_2 removed was in the range of $1,600 to $5,000. Costs were between $1,900 and $3,800 per ton of SO_2 for wet FGDs. While the SO_2 capital costs computed with CUECost for SDs were consistent with the literature at 250 MMBtu/hr, the capital costs computed for wet FGDs were high compared to values reported in the literature.
- *Fuel switching*. While not a control technology *per se*, the emission reduction benefits of fuel switching are directly proportional to the difference in sulfur contents of the fuels. Fuel switching requires considerable cost and operational analyses. In the NESCAUM region, residual oil is commonly used in ICI boilers. Switching from a 3 to a 1 percent sulfur residual oil can provide cost-effective SO_2 reductions at about $771 per ton of SO_2 removed. For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2, as well as in $PM_{2.5}$. The cost of switching to distillate oil is estimated to be much higher than for residual oil, because the higher cost of distillate oil.

6.3 PM Controls

ICI boilers burn a variety of fuels that contain fly ash and thus emit PM. PM control technologies have been commercially available and widely used in EGU boilers for many years. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired boilers. They are very effective in removing total PM and $PM_{2.5}$, with most options removing greater than 99 percent. The options include: (1) *fabric filters or baghouses*; (2) *wet and dry electrostatic precipitators (ESPs)*; (3) *venturi scrubbers*; (4) *cyclones*; and (5) *core separators*. Control technology decisions should be made on a case-by-case basis that accounts for technical, economic, and regulatory considerations. Fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM removed for coal and up to $15,000 per ton of PM removed for oil. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can have a larger parasitic consumption – up to 10 kW/1000 acfm or higher.

APPENDIX A: Survey of Title V Permits in NESCAUM Region

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Solutia Incorporated	MA	Foster Wheeler	249	Coal (Bit. 0.7%S)	-	0.027	baghouse (Carborundum Environmental Systems)	1.2	-	0.525	OFA (Foster wheeler)	-
St. Gobain Abrasives	MA	Riley	230	Coal (Subbit. 0.63%S)	-	0.1	Dust Collector	1.1	-	0.45	LNB	-
UMASS Amherst	MA	Union Iron Works	80	Coal	-	0.12	baghouse	1.1	-	0.43	-	Convert to CHP No. 2 (9/07)
Cooley Dickinson Hospital	MA	Early 1980s	-	Wood	-	-	-	0.008	-	0.16	-	-
Cooley Dickinson Hospital	MA	2006/ AFS Energy Systems	29.88	Wood	-	0.01	Cyclone, Baghouse	0.025	-	0.15	FGR	-
Seaman Paper	MA	2006/ Hurst Boiler	29.88	Wood	-	0.01	Baghouse	0.025	-	0.15	FGR	-

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Cornell University	NY	-	248	Coal	-	0.3	Fabric Filter	Coal 1% S by weight	-	0.4	-	
Cornell University	NY	-	117	Coal	-	0.35	Fabric Filter	Coal 1% S by weight	-	0.4	-	-
Commonwealth Plywood	NY	-	16	Wood	-	-	Multi-Cyclone w/o Fly ash injection	-	-	-	-	-
Crawford Furniture	NY	-	6	Wood	-	-	Single Cyclone	-	-	-	-	-
Deferiet Paper Company	NY	1945/ Combustion Engineering	190	Coal	-	0.46	Multi-Cyclone w/o Fly ash injection, and wet Venturi scrubber	2.5	-	0.5	-	-
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 13

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 14
Eastman Kodak	NY	-	478	Coal (Bit.)	#2 Oil	0.26	ESP	-	-	-	-	Boiler # 15
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 41
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 42
Eastman Kodak	NY	-	640	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 43
Eastman Kodak	NY	-	705	Coal (Bit.)	#2 Oil	0.035	ESP	.6 (coal)	-	0.42	-	Boiler # 44

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Gunlocke Co.	NY	E. Keeler	18	Wood	Oil #2	0.53	Fly Ash Cyclone	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	14.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	41.54	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	27.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Lyonsdale Biomass	NY	Zurn	290	Wood	-	0.1	-	-	-	0.2	-	
Morton International	NY	-	138	Coal	-	0.34	Fabric Filter, ESP	1.7	-	0.5	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
SUNY at Binghamton	NY	International Boiler Works	100	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	X3
SUNY at Binghamton	NY	International Boiler Works	50	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	
US Salt - Watkins Glen Refinery	NY	2000?	160	Coal and/or Wood	NG and/or Coal, Wood	0.051	Fabric Filter	1.2	-	0.18	SNCR	
Dirigo Paper	VT	1977	180	Wood	-	0.20 gr/dscf	multiclone	-	-	0.3	none	-
Ethan Allen	VT	1950	59.5	Wood	-	0.45 gr/dscf	multiclone	-	-	1.94lb/ton wet wood 7.45lb/ton dry wood	none	-
Fraser	NH	1981, Zurn	324	Wood/Bark/Paper	# 6 Oil	0.1	Multi-cyclone + Venturi scrubber	0.8	-	0.25	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Tillotson Rubber	NH	1978	41	Wood	-	0.43	Multi-cyclone	-	-	-	-	
Allen Rogers Limited	NH		5	Wood								
Allen Rogers Limited	NH		5	Wood								
Forest Products Processing Center	NH		47	Wood								
Madison Lumber Mill	NH		13	Wood								
Chick Packaging	NH		10	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Ossipee Mountain Land Company	NH		4	Wood								
Ossipee Mountain Land Company	NH		4	Wood								
Tommila Brothers	NH		11	Wood								
Monadnock Forest Products	NH		30	Wood								
Whitney Brothers Company	NH		2	Wood								
HG Wood Industries	NH		9	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Design Contempo	NH		19	Wood								
Design Contempo	NH		13	Wood								
Solon Manufacturing	NH		9	Wood								
Rochester Shoe Tree/Ashland	NH		4	Wood								
Precision Lumber	NH		9	Wood								
King Forest Industries - Wentworth	NH		29	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Peterboro Basket Company	NH		3	Wood								
Souhegan Wood Products	NH		8	Wood								
Souhegan Wood Products	NH		1	Wood								
Souhegan Wood Products	NH		1	Wood								
Concord Steam Corporation	NH		40	Wood								
Concord Steam Corporation	NH		40	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Boyce Highlands	NH		4	Wood								
Herrick Millwork	NH		5	Wood								
Northland Forest Products	NH		5	Wood								
Anthony Galluzzo Corporation	NH		4	Wood								
Cousineau Wood Products	NH		14	Wood								
Newport Mills Inc	NH		6	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Newport Mills Inc	NH		6	Wood								
Catamount Pellet Corporation	NH		40	Wood								
Durgin & Crowell Lumber Company	NH		10	Wood								
GH Evarts & Company	NH		7	Wood								

References: State Title V Permits, Coal SO_2 Database, ICI Coal Database, MA ICI 100-250 Boiler Database, VT ICI Boiler Database

APPENDIX B: CUECost-ICI Inputs

INPUTS

Description	Units	Input 1	Input 2	Input 3	Input 4	Input 5
General Plant Technical Inputs						
Location - State	Abbrev.	PA	PA	PA	PA	PA
Combustion Configuration	Abbrev.	PC	PC	PC	PC	PC
MW Equivalent of Flue Gas to Control System	MW	25	25.1	28.6	28.6	32.9
Net Plant Heat Rate	Btu/kWhr	10,000	11,370	8,750	8,750	7,600
Plant Capacity Factor	%	66%	66%	66%	66%	66%
Total Air Downstream of Economizer	%	154%	169%	118%	118%	119%
Air Heater Leakage	%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350	350	350	350
Inlet Air Temperature	°F	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013	0.013
Ash Split:						
Fly Ash	%	85%	85%	85%	85%	85%
Bottom Ash	%	15%	15%	15%	15%	15%
Seismic Zone	Integer	1.0	1.0	1.0	1.0	1.0
Retrofit Factor	Integer	1.0	1.0	1.0	1.0	1.0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	2	3	4	5	6
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No	No
Economic Inputs						
Cost Basis -Year Dollars	Year	2006	2006	2006	2006	2006
Service Life (levelization period)	Years	15	15	15	15	15
Inflation Rate	%	3%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	8%	8%	8%	8%	8%
AFDC Rate (current $'s)	%	8%	8%	8%	8%	8%
First-year Carrying Charge (current $'s)	%	22%	22%	22%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%	17%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%	16%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%	12%	12%	12%
Sales Tax	%	6%	6%	6%	6%	6%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	3%	3%	3%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	478.7	478.7	478.7	478.7	478.7
If "No" input escalation rate.	%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%	3%

Operating Labor Rate	$/hr	$25	$25	$25	$25	$25
Power Cost	Mills/kWh	47	47	47	47	47
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs

SO_2 Removal Required	%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2	2
(1 = yes, 2 = no)						
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Reagent Feed Ratio	Factor	1.05	1.05	1.05	1.05	1.05
(Mole CaCO3 / Mole SO_2 removed)						
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1	1
(1 = stacking, 2 = landfill, 3 = wallboard)						
Number of Absorbers	Integer	1	1	1	1	1
(Max. Capacity = 700 MW per absorber)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Absorber Pressure Drop	in. H2O	6	6	6	6	6
Reheat Required ?	Integer	1	1	1	1	1
(1 = yes, 2 = no)						
Amount of Reheat	°F	25	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton	$25	$25	$25	$25	$25
Stacking Disposal Cost	$/ton	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

<u>Lime Spray Dryer (LSD) Inputs</u>

SO_2 Removal Required	%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147	147
Reagent Feed Ratio	Factor	0.90	0.90	0.90	0.90	0.90
(Mole CaO / Mole Inlet SO_2)						
Recycle Rate	Factor	30	30	30	30	30
(lb recycle / lb lime feed)						
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)						
Absorber Material	Integer	1	1	1	1	1
(1 = alloy, 2 = RLCS)						
Spray Dryer Pressure Drop	in. H2O	5	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$60	$60	$60	$60	$60
Dry Waste Disposal Cost	$/ton	$25	$25	$25	$25	$25
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Particulate Control Inputs

Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.03	0.01	0.01	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	6	6	6
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2	2
Gas-to-Cloth Ratio	acfm/ft^2	5.5	5.5	5.5	5.5	5.5
Bag Material (RGFF fiberglass only)	Integer	1	1	1	1	1
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)						
Bag Diameter	inches	6	6	6	6	6
Bag Length	feet	20	20	20	20	20
Bag Reach		3	3	3	3	3
Compartments Out of Service	%	10%	10%	10%	10%	10%
Bag Life	Years	2	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
ESP:						
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0	10.0	10.0
Plate Spacing	in.	12	12	12	12	12
Plate Height	ft.	36	36	36	36	36
Pressure Drop	in. H2O	3	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOx Stoichiometric Ratio	NH3/NOx	0.9	0.9	0.9	0.9	0.9
NOx Reduction Efficiency	Fraction	0.70	0.70	0.70	0.70	0.70
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.4
Space Velocity (Calculated if zero)	1/hr	3000	3000	11800	11800	16800
Overall Catalyst Life	years	4	4	4	4	4
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Catalyst Cost	$/ft3	356.34	356.34	356.34	356.34	356.34
Solid Waste Disposal Cost	$/ton	25.38	25.38	25.38	25.38	25.38
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
Number of Reactors	integer	1	1	1	1	1
Number of Air Preheaters	integer	1	1	1	1	1

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	1:Urea 2:Ammonia	1	1	1	1	1
Number of Injector Levels	integer	3	3	3	3	3
Number of Injectors	integer	18	18	18	18	18
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1	1	1
NOx Reduction Efficiency	Fraction	0.50	0.50	0.50	0.50	0.50
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.2
NH3/NOx Stoichiometric Ratio	NH3/NOx	1.2	1.2	1.2	1.2	1.2
Urea/NOx Stoichiometric Ratio	Urea/NOx	1.2	1.2	1.2	1.2	1.2
Urea Cost	$/ton	200	200	200	200	200
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Water Cost	$/1,000 gal	0.22	0.22	0.22	0.22	0.22
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Low-NOx Burner Technology Inputs

NOx Reduction Efficiency	fraction	0.40	0.40	0.40	0.40	0.40
Boiler Type	T:T-fired, W:Wall	W	W	W	W	W
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%

Natural Gas Reburning Inputs

NOx Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	4.24	4.24	4.24	4.24	4.24
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Proposed BACT Alternative

November 19, 2018

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1.0 Introduction

The Fairbanks North Star Borough (FNSB) has levels of fine particulate matter ($PM_{2.5}$) that are above the health based National Ambient Air Quality Standard (NAAQS). In November 2009 the area was designated as a Moderate Nonattainment Area (NAA) based on monitoring data indicating the area did not meet the 2006 24-hour $PM_{2.5}$ standard. On April 28, 2017, the area was re-designated as a “Serious” NAA as a result of not attaining the $PM_{2.5}$ standard within 5-years from designation. As a result, the state is required to propose additional measures to bring the area into compliance within 10-years from designation (i.e., December 2019).

Once EPA re-classified the FNSB $PM_{2.5}$ nonattainment area to Serious, it triggered the requirement for stationary sources with over 70 tons per year (tpy) potential to emit (PTE) for $PM_{2.5}$ or its precursors (SO_2, NO_x, VOC, & NH_3) to conduct a Best Available Control Technology (BACT) analysis. Based on the Alaska Department of Environmental Conservation (ADEC) preliminary evaluations, sulfur dioxides are being evaluated for point source control measures under BACT. At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO2) control. Preliminary Determinations by ADEC suggest a capital cost to Aurora Energy, LLC (Aurora) for BACT compliance of $12,332,076 for an 80% removal efficiency using dry sorbent injection.

Aurora asserts that the proposed Best Available Control Technologies for sulfur dioxide emissions are not economically feasible. Confronted with this fact, ADEC and the EPA have asked Aurora to suggest an alternative to the ADEC proposed BACT. Within the context of this document Aurora is providing a proposal for alternative BACTs, all of which mitigate Aurora’s impact to the nonattainment area problem.

The alternative BACTs proposed by Aurora provide meaningful solutions in offsetting the largest contributing factor to the $PM_{2.5}$ problem in Fairbanks: home heating. The alternative BACTs being proposed by Aurora are more efficient from a dollar per ton of pollutant removed than the ADEC proposed BACT. Aurora strongly believes that these alternatives can have a more positive impact to the air quality issue than the ADEC proposed BACT. Before implementing these alternative BACTs, Aurora needs ADEC and EPA to agree that these alternative BACTs satisfy Aurora’s obligations for compliance with the NAA issue and that future controls to address $PM_{2.5}$ in the NAA will not be required.

Additionally, Aurora is making this alternative proposal based on the premise that ADEC and EPA will consider a precursor demonstration to determine the actual contribution of $PM_{2.5}$ by the point sources in the NAA. It has been stated repeatedly that the point sources are not the primary cause of the $PM_{2.5}$ problem. However there has never been a thorough analysis done to understand to what extent the point sources are or are not contributing to the problem. Should a precursor demonstration show that the point sources within the NAA are not major contributors to the $PM_{2.5}$ problem, all $PM_{2.5}$ compliance requirements imposed on the point sources shall be vacated. If however the precursor demonstration shows that the point sources are above the insignificance threshold, the alternative BACTs proposed by Aurora would satisfy the requirements for compliance within the NAA.

In closing, Aurora desires to be a part of the solution to reduce the $PM_{2.5}$ levels within the NAA. Aurora remains convinced that the ADEC proposed BACT is cost prohibitive and an inefficient use of funds. Instead Aurora is proposing alternative BACTs that directly help solve the PM2.5 problem. In proposing these alternatives, Aurora needs ADEC and the EPA to agree to continue to study the source of PM2.5

pollution as well as confirm that these alternative BACTs meet Aurora's compliance with the Clean Air Act for purposes of NAA attainment.

1.1 ADEC BACT Analysis

ADEC provided its review of a BACT analysis for Aurora which included an evaluation of technologies to mitigate emissions of oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form $PM_{2.5}$ in the atmosphere post combustion. The BACT analysis evaluated all available control options for equipment emitting the triggered pollutants and followed a process for selecting the best option based on feasibility, economics, energy, and other impacts. The results of the BACT analysis are reflected in Table 1.

Table 1: Department Economic Analysis for Technically Feasible NOx and SO_2 controls.

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 3,930,809.00	$ 957,728.00	$ 2,226.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 17,331,770.00	$ 2,787,995.00	$ 3,240.00
Dry Sorbent Injection (DSI)[2]	SO_2	$ 12,332,076.00	$ 4,284,104.00	$ 6,308.00
Spray Dry Absorber (SDA)[2]	SO_2	$ 60,270,115.00	$ 11,862,577.00	$ 15,525.00
Wet Scrubber (WS)[2]	SO_2	$ 65,957,875.00	$ 12,160,961.00	$ 14,469.00

1 - Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)

2 - Capital Recovery Factor = 0.1098 (7% interest rate for a 15 year equipment life)

1.2 Aurora BACT Analysis

The ADEC requested additional information concerning Aurora's BACT analysis in a letter dated September 13, 2018. One of the ADEC's request were that Aurora comment on the cost analysis spreadsheets developed by ADEC and provided with the Preliminary Draft SIP. Comments were made on the spreadsheets and submitted to the ADEC on November 1, 2018. Below (Table 2) are the results of Aurora's inputs considering EPA and ADEC's comments. Spreadsheets are included along with this proposal for review by the agencies. Several changes to the inputs are documented in the summary for the spreadsheet inputs (See Appendix A & B). In conjunction with the changes made to the spreadsheets, site-specific quote for SO_2 controls, namely Dry Sorbent Injection (DSI), was provided to the ADEC as requested and included as a parameter within the cost analysis spreadsheets for the referenced control technologies. The EPA is requiring that the cost analyses include a 30 year equipment life for the control technologies except SNCR which is evaluated for 20 year equipment life.

Table 2: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.1

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[2]	NOx	$ 6,208,948.00	$ 989,197.00	$ 3,107.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 2,921,054.00	$ 4,587.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,601,940.00	$ 8,423.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 51,115,267.00	$ 8,716,232.00	$ 12,408.00
Wet Scrubber (WS)[1,3]	SO_2	$ 56,318,290.00	$ 8,839,892.00	$ 11,440.00

1 – Capital Recovery Factor = 0.0669 (5.25% interest rate for a 30 year equipment life) [EPA requirement per comments]
2 – Capital Recovery Factor = 0.0820 (5.25% interest rate for a 20 year equipment life) [EPA requirement per comments]
3 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

Table 3 reflects another iteration (V.2) of Aurora's changes to the ADEC's spreadsheets. The results in Table 3 consider a lower emission rate for both SO_2 and NO_x based on 2011 source testing information and/or additional information. The SO_2 emission rate assumed by the state and Aurora has been 0.39 lbs/MMBtu. The coal analysis for feed coal during the test showed elevated sulfur content (0.18%) in comparison to the 5-year weighted average sulfur content from 2013-2017 (0.14 %). Using a conservative conversion from sulfur content (0.14%) to sulfur dioxide, the 5-year weighted average SO_2 emission rate would be 0.36 lbs/MMBtu. This conservative emission rate was used in the calculations to derive the cost effectiveness values in Table 2. The sulfur content during the source test conducted in 2011 (0.18%) when converted to a heat input emission rate considering total conversion of sulfur to SO_2 yields an emission factor of 0.48 lbs/MMBtu. The actual tested emission rate was 0.40 lbs/MMBtu. The emission rate for SO_2 was 83% of the maximum potential. This suggests there is 17% capture of sulfur compounds in the ash. As such, the emission rate derived and used in Table 3, considers a 17% capture of sulfur in the ash. The conversion of sulfur to SO_2 based on the 5-year weighted average sulfur content in coal and a 17% capture rate yields 0.30 lbs/MMBtu (0.36 lbs/MMBtu X 0.834 = 0.30 lbs/MMBtu). The results in Table 3 account for the current sulfur content in coal and the rate adjustment for sulfur capture fraction from the process based on a source test conducted in 2011.

Also accounted for in Table 3 is a more realistic equipment life expectancy for the facility and control equipment. It is not reasonable to consider a 30 year and 20 year life expectancy for the control equipment and the boilers. Considering the age of the Chena Power Plant, Units 1-3 are 50,000 lb/hr boilers that were installed in the early 1950s, and Unit 5 is a 200,000 lb/hr boiler which was installed in 1970. Units 1-3 are already +65 years and Unit 5 is +45 years old. A 30 year horizon should not be applicable to the Chena Power Plant. A 15 year equipment life is considered in the following cost effectiveness analysis (Table 3).

Table 3: Adjustment of ADEC Economic Analysis for Technically Feasible NOx and SO_2 Controls – V.2

Technology	Pollutant	Capital Cost ($)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
Selective Non-Catalytic Reduction (SNCR)[1]	NOx	$ 6,208,948.00	$ 1,088,694.00	$ 3,419.00
Selective Catalytic Reduction (SCR)[1]	NOx	$ 25,758,941.00	$ 3,721,132.00	$ 5,844.00
Dry Sorbent Injection (DSI)[1]	SO_2	$ 20,682,000.00	$ 4,914,480.00	$ 10,785.00
Spray Dry Absorber (SDA)[1]	SO_2	$ 50,880,540.00	$ 10,084,456.00	$ 17,213.00
Wet Scrubber (WS)[1,2]	SO_2	$ 56,318,290.00	$ 10,314,589.00	$ 16,005.00

1 – Capital Recovery Factor = 0.0980 (5.25% interest rate for a 15 year equipment life)
2 – Does not include costs associated with building and maintaining a wastewater treatment facility. [Notation from ADEC spreadsheet]

2.0 Economic Infeasibility

The BACT review process as outlined by EPA includes five-step approach to determine the best control option. The economic feasibility of potential measures are addressed under Step 4 of the review process. Since there is no cost threshold for economic feasibility for controls within a serious nonattainment area, a source has to make the assertion to the regulatory agencies in order for economic infeasibility to be considered. Aurora's BACT results, as illustrated in Table 3, show that the least expensive SO_2 control technology is a $20 million dollar investment and the cost effectiveness value is above $10,000/ton of SO_2 removed.

Therefore, per the fine particulate implementation guidance, if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology demonstrated to be economically feasible, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators to the extent applicable:[1]

1. Fixed and variable production costs;
2. Product supply and demand elasticity;
3. Product prices (cost absorption vs. cost pass-through);
4. Expected costs incurred by competitors;
5. Company Profits;
6. Employment costs;
7. Other costs (e.g., for BACM implemented by public sector entities).

At this time, ADEC is considering one control measure per major stationary source to meet BACT and Most Stringent Measures (MSM) for sulfur dioxide (SO_2) control. ADEC's preliminary determination suggests Aurora invest $12,332,076 for DSI technology to remove 80% of the SO_2 emissions from the Chena Power Plant. ADEC estimates that annualized costs for the application would be $4,284,104. ADEC's projected capital cost for retrofit SO_2 control technology is just above half of the costs of a +50/-30 design (e.g., capital cost $20,682,000) which was recently submitted to the ADEC. Even if the lower cost for controls estimated by the ADEC were valid, it is not economically feasible and therefore should not be required. Further, ADEC does not know whether the installation of DSI or any control technology on stationary sources will have a significant impact on the overall air quality in the non-attainment area.

Aurora has one electric customer and approximately 200 district heating customers. Income from power production is from wholesale electric sales to the local electrical cooperative, Golden Valley Electrical Association (GVEA). Aurora has a long term contract with GVEA which would be difficult to renegotiate for necessary price increases to accommodate additional control technologies. Pass-through cost opportunities for Aurora's district heating are not viable. The necessary product price increases to cover additional costs of the proposed control technology would price Aurora out of the market for both heat and power. The result would be higher electric and heat costs, coupled with an increase in $PM_{2.5}$ pollution due to the introduction of ground-level emissions from oil and/or gas fired furnaces and boilers that would be installed to replace uneconomic district heat. As Aurora customers switch to less expensive fossil fuels – or yet even less expensive wood – the resulting burden on Aurora's remaining customers will increase, causing more and more of them to switch, resulting in a continuous increase in particulate emissions in the Fairbanks core, and in a death spiral for Aurora as an economically viable business. Within this section, Aurora will address the financial indicators applicable to demonstrate the economic infeasibility of installing and operating ADEC's proposed control technology.

1. Production Costs

Aurora's five year operating costs for electric and district heating (RCA) are provided below in Table 4. Operating costs consist of operations expense, maintenance expense, administrative expenses, and depreciation expense. The net operating costs for power generation was $0.08/kW in 2017 (Table 4). The

[1] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085.

margin for income is small as reflected in Table 6. District heating operating costs exceed income generated resulting in a net loss over the past 5 years (Table 6). [2]

Table 4: Aurora Energy Operating Costs

Year	Electrical Total	Net kWh	$/kWh	District heating Total	Net MMBtu	$/MMBtu
2017	$13,795,480	181,113,600	$0.08	$4,658,655	262,189	$17.77
2016	$13,707,259	189,093,610	$0.07	$5,285,399	249,151	$21.21
2015	$12,582,952	194,083,220	$0.06	$5,395,212	267,686	$20.16
2014	$12,250,548	184,058,400	$0.07	$5,648,209	273,089	$20.68
2013	$10,833,349	181,569,600	$0.06	$5,387,853	274,139	$19.65
Average	***$12,633,918***	***185,983,686***	***$0.07***	***$5,275,066***	***265,251***	***$19.89***

2. Supply and Demand Elasticity

The issue of supply and demand elasticity is addressed in more detail within the context of the following sections. The cost of control technologies cannot be absorbed by Aurora under the current pricing to consumers for district heating and power. Aurora has no alternative but to pass those costs to its customers. Those customers, in turn, would have no choice but to go elsewhere for their heat and power, as Aurora would no longer be competitive with other options. This would be the beginning of a death spiral for Aurora as a business, and the beginning of an increase in lower level emissions in the Fairbanks core as more and more buildings switch to oil or gas for heat.

3. Product prices (cost absorption vs cost pass-through)

Aurora's current product prices are competitive with other power suppliers and heating sources. Aurora's heat business is generally regulated by the Regulatory Commission of Alaska (RCA). District heating prices are set based on Aurora's cost to produce the heat. At the same time, many district heat customers are able to switch to alternative sources of heat, such as oil, gas or wood; therefore, Aurora has a powerful incentive to maintain district heating prices competitive with other heating options. Likewise, GVEA maintains several contracts with various power producers including Aurora. GVEA's portfolio includes power generated with natural gas, hydroelectric gradient, wind, solar, coal, and oil. Aurora's contract with GVEA ensures Aurora's power pricing is competitive and marketable.

District Heating

District heating prices cannot absorb the pass through costs of control technology. Aurora's district heating customer base is approximately 200 including mostly commercial and some residential customers. District steam heating rates are set with oversight by the RCA and do not vary. Hot water district heating prices differ depending on consumers' annual heating needs. The hot water district heating rates are adjusted throughout the year to be competitive with other sources of heat.

Absorbing full or partial costs for upgrades or control technologies is not feasible through district heating rate adjustments. The price adjustment necessary to compensate for the current average annual net loss from district heating (Table 6) would be an increase of $3.71/MMBtu representing a 20% increase in heating costs. A 20% increase in district heat prices per unit energy (MMBtu) is not marketable. The potential is a loss of revenue from customers switching to alternative forms of heat which would make

[2] Based on RCA annual filing from 2013-2017.

district heating even less sustainable and exacerbate air quality due to an increase in ground level emissions.

Electric Generation

Aurora's power pricing cannot absorb the pass through cost of control technologies without revising the current contract and becoming less marketable. Aurora sells its power at wholesale price to GVEA, its sole electric customer. Aurora has averaged 186,000 MWh in net sales annually. Pass through of any additional incurred cost would have to be negotiated with GVEA, and would cause an increase in power costs to all customers in GVEA's service area.

Product Pricing for GVEA including Control Technology Costs

ADEC indicates that SO_2 controls are being considered for BACT or Most Stringent Measures (MSM) at this time.[3] ADEC's estimate of the capital investment of the preferred control technology for Aurora is estimated to be $12,332,076 and the annualized cost is estimated to be $4,284,104. The requirement is that BACT must be installed within 4 years of reclassification of an area from a moderate to a serious nonattainment area.[4] The Fairbanks North Star Borough nonattainment area designation change from "Moderate" to "Serious" was effective June 9, 2017.[5] Since the area is now identified as serious, BACT control would have to be in place by June of 2021. Funds for the capital investment would need to be arranged by 2019 to allow for construction and installation of the control equipment. The power purchase agreement with GVEA would need to be renegotiated prior to committing to construction.

Assuming electrical sales would correspond to the 5-year average (185,984 MWh), the weighted average price per MWh at the Chena Power Plant (CPP) would be $85.51.[6] When the annualized cost of operating the preferred control technology is included, the price of power from the CPP increases to $108.55/MWh; a 27% increase in price of power. The average total electric power consumption of sulfur control on Healy Unit #2 is 550.5 kW.[7] Assuming a comparable station service use, SO_2 control on the Chena Power Plant could require an additional 2.6% for station service load.

The SO_2 control technologies being considered (DSI) require the addition of lime, limestone, or sodium bicarbonate to the gas path prior to the baghouse. The amount of unreacted sorbent added to the process could alter the leaching characteristics of metals from coal ash. Recent testing of coal ash from coal blended with 2% by weight limestone, demonstrated elevated metals leaching from coal ash at various pH. Metals leaching in excess of water quality standards could require Aurora to incur additional disposal costs for coal ash. Aurora would either have to build a coal ash landfill, or take the coal ash to the municipal landfill at a cost to Aurora of $90/ton.[8] If additional costs were incurred by Aurora for disposing 20,000 tons of coal ash, then the price per MWh would need to increase to $118.60; which represents a 39% increase in the price of power.

[3] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[4] Federal Register, Vol. 81, No.164, Wednesday August 24, 2016.
[5] Federal Register, Vol. 82, No.89, Wednesday May 10, 2017.
[6] 2013 Contract Pricing for 2020: $79.37/MWh ($\leq$150,000 MWh) + $112.12/MWh (>150,000 MWh).
[7] Alaska Industrial Development and Export Authority. 1999. Spray Dryer Absorber System Performance Test Report, Healy Clean Coal Project. Healy, AK.
[8] FNSB. 2014. Interior AK Coal Ash. Pg. 42

Table 5: $/kWh Wholesale Pricing for GVEA including Control Technology Costs

	Average kWh/year (2013-2017)	No Controls	SO2 - DSI	SO2 - SDA	SO2 - WS
Annual BACT Operating Cost		$ -	$4,284,104	$11,862,577	$12,160,961
2020 ($/kWh)	185,983,686	$ 0.09	$ 0.11	$ 0.15	$ 0.15
2020 ($/kWh) -2.5% station load (BACT)	181,334,094	$ 0.08	$ 0.11	$ 0.15	$ 0.15
Coal Ash Disposal - Borough Landfill[1]		$ -	$ 0.12	$ 0.16	$ 0.16

1 - Borough Landfill disposal cost based on 20,000 tons of ash; $90/ton (FNSB. 2014). Interior AK Coal Ash. Pg 42.

Aurora's price of power is in competition with other power producers. If the price of power exceeds that of the competition, Aurora would not be as competitive in the energy market. Currently, GVEA will take as much power as Aurora can produce; however, it is likely that GVEA would reduce the amount of power accepted from Aurora if product prices increase above those of the competition.

4. Expected costs incurred by competitors

The FNSB nonattainment area impacts stationary sources within the area. Aurora's main competitors are power producers outside of the nonattainment area. Aurora's competition will not be required to consider BACT or MSM as a new requirement of a nonattainment area. This puts Aurora at a serious economic disadvantage. It is the only private for-profit power producer in the state being subjected to the $PM_{2.5}$ nonattainment area BACT requirements. Table 5 illustrates the price of wholesale power in $/kWh from Aurora. The price of power with controls is $0.11/kWh. When additional disposal requirements are considered as a result of the use of the control technology, the price of Aurora's wholesale power to GVEA is $0.12/kWh.

Aurora's competition for power sales is primarily natural gas generated power; including Anchorage Municipal Light and Power (AMLP), Matanuska Electric Association, Inc. (MEA), and Chugach Electric Association (CEA). Aurora is also in competition with GVEA's fleet including the coal facilities (Healy #1 and Healy #2). The expected increase in price of Aurora's power due to BACT will make its power less marketable. At $0.12/kWh, the price of Aurora's power to GVEA would exceed AMLP ($0.09/kWh), Healy #1 ($0.10/kWh), MEA ($0.10/kWh), and CEA ($0.11/kWh) based on GVEA's cost of power report in 2017[9]. Aurora currently provides 14% of GVEA's power requirements. At current prices, Aurora's power is competitive. An increase in the price of power to $0.11/kWh or $0.12/kWh would likely change that perspective.

5. Company Profits

Net income (loss) for Aurora over the past five years are not sufficient to absorb annual control technology costs for any of the control technologies proposed. Table 6 below includes the net income (loss) from district heating, electrical generation and the combined company income (loss) for years 2013

[9] 2017 GVEA Annual Report to the RCA.

through 2017. Net income (loss) include income generated from district heat and power sales minus the operating costs as presented in Table 2 and include nonutility income, interest income, miscellaneous amortizations, and interest expenses.

Table 6: Aurora Energy, LLC – 5 Year Net Income (Losses)

Year	Electric	District Heating	Net Income (loss)
2017	$ 801,037.00	$ (377,585.00)	$ 423,452.00
2016	$ 419,092.50	$ (1,808,914.00)	$ (1,389,821.50)
2015	$ 1,094,599.25	$ (1,059,348.00)	$ 35,251.25
2014	$ 321,876.05	$ (892,950.00)	$ (571,073.95)
2013	$ 420,072.77	$ (775,432.00)	$ (355,359.23)
Average	***$ 611,335.51***	***$ (982,845.80)***	***$ (371,510.29)***

The annual cost to operate the preferred technology is $4,284,104 (Table 1 & 4); the average 5-year net income (loss) for Aurora is ($371,510) [Table 6]. Conclusively, Aurora is not able to absorb the cost of additional control technologies.

The only alternative for Aurora to address annual operating expenses for any proposed control technologies would be to attempt to renegotiate the power contract to raise the price of power to GVEA. However, the rate adjustment would increase the price of Aurora's power to the extent that it would be less competitive.

6. Employment Cost

The state's calculations for annual operation costs of the proposed technologies include labor cost increases. The increases vary depending on the type of control technology. As a part of the state's analysis for SO_2 controls, annualized cost increases include the projection of additional labor for operation, maintenance, and administration.

7. Other Costs

No additional costs were considered.

ADEC has not shown that Aurora's, nor other stationary source's, SO_2 emissions are a significant contributor to the nonattainment area problem. ADEC does not know whether installation of BACT or MSM on stationary sources will significantly mitigate the impact of SO_2 on particulate concentration. Aurora cannot afford the control measure or technology that has been selected by the ADEC in the preliminary BACT analyses. The basis for this determination is that Aurora has consistently shown insufficient income to absorb the cost of the control technologies. Alternatively, increasing the price of power or heat to accommodate the cost of control technology will price Aurora's products out of the market. Any increase in district heating prices would make alternative sources of heat more attractive to consumers. The result would be a loss in business from customers switching to alternate sources of heat. This change in heating source could exacerbate pollution emissions at the ground level due to customers' use of distributed home heating alternatives. Aurora's district heating displaces the emissions from the equivalent of 2 – 2.5 million gallons of heating oil. The current power purchase agreement with GVEA allows Aurora's power to be competitive with other power sellers. The cost of additional control technology would have to be negotiated with Aurora's one customer based on its power purchase agreement and make Aurora's power prices less competitive; and subsequently, less sustainable.

3.0 Proposed Alternative BACT – District Heating

Aurora is sympathetic to the requirements of the Serious Nonattainment Area and believe that a reasonable alternative exists within the framework of what is economically feasible. As previously discussed, Aurora asserts that imposing retrofit controls, as proposed by ADEC, on its older boilers in the next four years is economically infeasible and could have negative impacts on the goals of the community to achieve attainment with the $PM_{2.5}$ standard. As such, Aurora has developed a list of mitigating measures that are more economically sustainable and will have a direct impact on the community with respect to achieving attainment with the $PM_{2.5}$ standard. Included as alternatives are the expansion of district heating, a wood drying kiln, and the potential use of biomass.

3.1 District Heating

Aurora is proposing that past district heat expansions as well as future district heating projects be considered as BACT for the Chena Power Plant. As it stands, Aurora's district heating displaces about 42 tons of SO_2 and 2 tons of particulates annually. District heating is referenced in both the Moderate Area State Implementation Plan (SIP)[10] and the Preliminary Serious Area SIP[11] as a Pollution Control Measure for the FNSB NAA. As stated in the Moderate Area SIP, "An increase in the coverage of the district heating systems would therefore result in a decrease in measured $PM_{2.5}$ concentrations". Based on modeling results, the $PM_{2.5}$ concentration attributed to Aurora during an episode in 2008 was 0.02 μg/m^3 and the SO_2 concentration at ground level from Aurora represents 0.75 μg/m^3 (See Table 7).[12] The implication of the small pollutant contribution from Aurora at ground level is that taller stacks decrease the impact from emissions at ground level. The amount of pollutant loading at ground level within the nonattainment area is mitigated by district heating through the removal of ground level source emissions and vertically displacing them. An added benefit to increasing district heat coverage is an increase in efficiency at the plant. The plant is generally base loaded and driven to operate at a maximum capacity; there is moderate room for growth, but realistically, the plant is nearing its maximum capacity. The plant could accommodate, roughly, an additional 100 MMBtu/hour of heating capacity while still being able to provide a modest amount of electricity.

Table 7: Summary of Six Major Fairbanks Point Source Plumes from CALPUFF for the Episode (Jan.23rd to Feb. 9th, 2008) Average Surface Concentrations at the State Office Building of PM2.5 and SO2 in ug/m3.

Power Plant	Episode average SO_2 (μg/m^3)	Episode average $PM_{2.5}$ (μg/m^3)
UAF- 316	2.75	0.16
Aurora- 315	0.75	0.02
Zehnder-109	0.48	0.19
Flint Hills-071	0.016	0.38
GVEA NP-110	3.8	1.45
Ft. WW- 1121	14	1.6
Total surface concentration	21.8	3.8

In order to quantify the impact district heating has on the nonattainment area, Aurora evaluates the potential use of fuel oil based on

[10] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 42.
[11] ADEC. 2018. *Preliminary Draft, Possible Concepts and Potential Approaches for the development of the FNSB NAA Serious SIP*.
[12] ADEC. 2014. Moderate Area State Implementation Plan. Section III.D.5.8-11.

a conversion from the heating load compensated by the plant for district heating. A fuel oil heating value of 137,000 btu/gal and an assumed efficiency of 85% for heating appliances are used to determine the quantity of heating oil equivalent to the district heating load. Since SO_2 and $PM_{2.5}$ are the pollutants of most concern, Aurora is using emission rates for fuel oil using EPA's emission inventory warehouse, AP-42. Using the value of 2566 ppm sulfur in heating oil[13], an emission rate of 36.92 lbs/10^3 gallons (2.64x10^{-1} lbs/MMBtu) for SO_2 emissions and 0.4 lbs/10^3 gallons (2.86 x10^{-3} lbs/MMBtu) for filterable or direct $PM_{2.5}$ and 1.3 lbs/10^3 gallons (9.29 x10^{-3} lbs/MMBtu) for condensable $PM_{2.5}$ are derived. Using these emission rates, Aurora can evaluate the impact of district heating on the removal of SO_2 and $PM_{2.5}$ from the nonattainment area.

As part of a further analysis, the SO_2 is converted to $PM_{2.5}$ by using an ADEC derived method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration from various sources. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Through the use of a dispersion model, CALPUFF, ADEC determined that 22% of modeled SO_2 concentration are from point sources at ground level, 78% are from central oil, and <1% from mobile sources. Using this information and the ADEC's methodology (based on 'scenario 2'), a ratio of 5.5 tons SO2 emissions from major sources is estimated to form 1 μg/m^3 of $PM_{2.5}$ as ammonium sulfate [8.38 TPD/(1.1 μg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 μg/m^3 of $PM_{2.5}$.[14] Based on the same methodology, the ratio of SO_2 from fuel oil (78% of modeled concentration) to particulates is 0.8 tons of fuel oil SO_2 emissions to 1 μg/m^3 of $PM_{2.5}$ as ammonium sulfate [4.12 TPD[15]/(3.9 μg/m^3 x 132g/mol of ammonium sulfate/96 g/mol sulfate)]. To summarize this information and that in Table 8, wood smoke produces 18 times more $PM_{2.5}$ than the SO_2 from point sources and 2.6 times more $PM_{2.5}$ than fuel oil.

Table 8: Source pollutant emission and equivalent contribution in μg/m^3 of $PM_{2.5}$.

Pollutant	Point Sources (SO_2)	Fuel Oil (SO_2)	Wood Smoke
Emissions (tons)	5.5	0.8	0.3
$PM_{2.5}$ Equivalent Concentration (μg/m^3)	1	1	1

3.2 District Heat Expansion

District heating from Aurora mitigates emissions from ground level sources. The 5-year average (2013-2017) heating value of Aurora's district heat supply is 265,251 mmbtu/year. That is equivalent to about 2.3 million gallons of heating oil per year; assuming a heating value of 137,000 btu/gal and an 85% efficiency for an oil fired furnace. Using these values, district heat displaces about 42 tons of SO_2 from ground level emissions per year and 2 tons of $PM_{2.5}$ in the down town area. Since 2008, Aurora has added district heating equivalent to 243,000 gallons of fuel oil per year. The impact of the addition is equivalent to the removal of 3510 lbs of wood smoke per year based on SO_2 reduction from fuel oil [4.5 TPY SO_2 fuel oil/0.77 tons SO2 fuel oil/1 μg/m^3 x 0.3 tons wood smoke/1 μg/m^3 x 2000 lbs/ton]. District heating records show that 67% of heating use is between November – March (151 days). The loading that

[13] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 102.
[14] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.
[15] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.6. pg 27.

was mitigated since 2008 is approximately 16 lbs/day of wood smoke equivalence during the winter months.

Aurora has the mechanical potential to expand district heating another 100 mmbtu/hr of additional heating. The equivalent SO_2 removal potential would be about 24 tons per year based on the displacement of 1.3 million gallons of heating oil No.2 (fuel oil S% = 0.26).

3.3 District Heating Economics

Installation of district heating can be costly. The evaluation of DH as a control technology for the plant is difficult to assess a cost/ton comparison. Ideally, the expansion cost would be mitigated by revenue generated from the use of district heating. The business model for district heating would justify the expansion; the added benefit would be the reduction in pollutants emissions from ground level sources, and a decrease in the output based emission rate. In general, efficiency gains at the plant is a sustainable practice with the benefit of reducing pollutant emissions at ground level.

3.4 Output Based Emission

District heat expansion has the added benefit of making the plant more efficient. A method of illustrating efficiency gains with respect to pollutant emissions is in the derivation of an output based emission rate. The output based emission rate for SO_2 at the plant is approximately 4.6 lbs/MW of energy output. The emission rate is based on a conservative calculation using the 5-year weighted average coal sulfur content and converting all of it to SO_2. The denominator consists of net power and net district heat sales in MW. When the maximum output of district heating is added to the denominator, the emission rate is reduced to 3.4 lbs/MW. This represents a 27% reduction in the emission rate per energy output.

The output based emission rate can be used to show efficiency gains with respect to pollutant emissions. Efficiency gains through the use of central heat and power facilities clearly demonstrate the advantages of minimize emission increases while maximizing energy output.

4.0 Proposed Alternative BACT - Firewood Drying Kiln

Couched within the benefits of district heating, Aurora is proposing an alternative to address its potential formation of fine particulate matter ($PM_{2.5}$) from sulfur dioxide. According to a 2008 report by the Northeast States for Coordinated Air Use Management (NESCAUM), for every 10 percentage point increase in the moisture content of wood, the $PM_{2.5}$ emissions increase by 65% to 167%. The increase in emissions is due to increased amount of wood needed to evaporate the extra moisture and poor combustion conditions leading to reduced heat transfer efficiency. Wood fuel use may double if wet wood were burned as opposed to dry wood.[16] Aurora is proposing to develop and operate a firewood drying kiln using district heat from the Aurora plant to help mitigate the use of wet wood. The general idea is that, along with district heat conversions, Aurora would offset its potential $PM_{2.5}$ formation by providing dry wood to the community from a kiln. The kiln would require 3.5 mmbtu/hour of thermal loading from district heating. The initial moisture content in the wood is assumed to be around 50%; the kiln would evaporate 35% of the moisture to a wood moisture content of 15% or less. By conditioning solid fuel (fire wood) to be used in homes, district heating is effectively expanded without the cost of installation.

[16] ADEC. 2014. *Moderate Area State Implementation Plan. Appendix III.D.5.7.* pg 22.

4.1 Equivalent Emissions

The state has derived a method for comparing direct emissions of pollutants to $PM_{2.5}$ concentration. Using this methodology, point source SO_2 emissions, wood smoke emissions, and heating oil SO_2 can be correlated to $PM_{2.5}$ concentration. Based on 22% of modeled SO_2 concentration from point sources at ground level, a ratio of 5.5 tons SO_2 emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$ as ammonium sulfate. Likewise, a ratio of 0.3 tons of wood smoke emissions is estimated to form 1 µg/m^3 of $PM_{2.5}$.[17] Using the fore mentioned conversions, Aurora estimated the power plants SO_2 emissions equivalent to wood smoke emissions. Based on an emission rate at Aurora of 608.3 tons/year of SO_2 (1.67 tpd), the wood smoke emission equivalent is 181 lbs/day [1.67 TPD/ (5.5 tons SO_2 from major sources/1 µg/m^3) x 0.3 tons of wood smoke/1 µg/m^3 x 2000 lbs/ton]. The equivalent annual wood smoke emission to 608.3 tons of SO_2 emission is proposed to be mitigated through drying wood by reducing 35% moisture from cord wood.

Table 9: SO2 Conversion to Wood Smoke Equivalent Emission

Source of Emissions	SO_2 Emissions (tpd)	$SO_2/PM_{2.5}$ (tpd)/(µg/m^3)	Wood Smoke/$PM_{2.5}$ (tpd)/(µg/m^3)	Wood Smoke Equivalent (lbs/day)
Aurora Energy	1.67	5.5	0.3	181
Displaced Heating Oil Use - DH	0.01	0.8	0.3	10

The emission reduction for $PM_{2.5}$ in lbs/MMBtu was derived using the ADEC's referenced information within the Appendices of the Moderate Area State Implementation Plan (See Tables 10 & 11). The average emission rate for wood burning devices at 50% moisture (1.14 lbs/MMBtu) was subtracted from the average emission rate for wood burning devices at 15% moisture (0.67 lbs/MMBtu). The equivalent amount of cords needed to account for 100% of Aurora's annual SO_2 emissions is 8,495 cords per year.

Table 10: Emission Factors based on wood moisture content

Wood Burning Devices	EF PM2.5 lbs/ton[1]	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu	Btu/lb[2]	lbs/MMBtu
Moisture content (%)		0		15		50	
non-EPA certified Wood Stoves	11.6	8,119	7.14E-01	6,901	8.40E-01	4,060	1.43E+00
EPA Wood stove non-catalytic	7.57	8,119	4.66E-01	6,901	5.48E-01	4,060	9.32E-01
EPA Wood stove catalytic	8.4	8,119	5.17E-01	6,901	6.09E-01	4,060	1.03E+00
Hydronic Heater weighted 80/20 (OWB unqualified/OWB-Ph2)	9.43	8,119	5.81E-01	6,901	6.83E-01	4,060	1.16E+00
Average emission factor	9.25	8,119	5.70E-01	6,901	6.70E-01	4,060	1.14E+00
Note: 1 - Appendix III.D.5.6-105, Table 5.6-40; 2 - Appendix III.D.5.6-86, Table 5.6-31							

[17] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

Table 11: Calculation to determine how much kiln dried wood is necessary to mitigate AE's SO_2 emissions.

PM 2.5 Daily Emissions Reduction [Scenario 2] (lbs/day)	181
PM 2.5 Annual Emissions Reduction (lbs/year)	66,003
Spruce weight at 20% moisture	2,550
Dry Wood (%) moisture	15
Wet Wood (%) moisture	50
Emission Diff. wet vs. dry (lbs/MMBtu)	4.69E-01
Daily Wood processing minimum (MMBtu/year)	140,695
Cords per year	8,495
cords/load	42
Loads per year	202

4.2 Firewood Kiln Economics

The capital cost and annualized cost of the kiln is much less than that of the other BACT alternatives. The cost effectiveness is determined by a $/Cost ratio based on drying wood at a maximum potential of 8,495 cords of wood to reduce, effectively, 608.3 tons per year of SO_2-equivalent emission. The annualized cost is used to derive the cost effectiveness ratio of $980 per ton of pollutant removed.

Table 12: Cost Effectiveness of Kiln

Control Technology	PM 2.5 Reduction (tpy)	Equivalent SO2 Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Cost ($/year)	Cost Effectiveness ($/ton SO_2)
Wood Kiln	32.5	608.3	$ 1,500,000	$ 736,078	$ 980

Unlike a traditional BACT approach, the effective emission reduction is hinged on the marketability of dry wood. Aurora plans to market the kiln dried wood as a benefit from a performance and air quality standpoint. The Fairbanks Northstar Borough, ADEC and EPA all have an important role in enforcing the use of dry wood for home heating the NAA.

5.0 Proposed Alternative BACT - Biomass Co-Firing

Aurora's boilers are subject to 40 CFR 63 subpart JJJJJJ. Under the rule, the Chena Power Plant (CPP) boiler units are classified as coal-fired boilers. The definition of coal-fired boiler subcategory extends to coal boilers that burn up to 15% biomass on a total fuel annual heat input basis. This flexibility in definition would allow Aurora to burn up to 15% biomass and still retain its classification as a coal-fired boiler. Aurora has been involved in a projects with Alaska Center for Energy and Power (ACEP) and the US Forestry Service using biomass (wood chips and refuse) as a substitute for coal. The projects did not demonstrate much of a change to the current operations; however, the material used had a significant amount of moisture (40%) and was not uniform. Sizing of the material was an issue and created problems. Biomass refuse and chips were not appropriately sized and created issues with material feeding through the auxiliary coal feed system. Also, due to density differences, material segregation within the bunkers occurred; wood chips tended to be pushed to the top of the coal. Ultimately, the lessons learned from the project were that with the right material sizing and processing, biomass could be used in the boilers to

help increase efficiency. As noted by operators during the project, the biomass burned off quickly leaving holes within the coal bed which allowed for air pockets which qualitatively made coal combustion more effective. The theory is that air voids left after the biomass was burned off facilitated greater air-to-fuel contact. Also, the rapid burning of the biomass may have increased the heat of the coal bed which helped coal combustion. Although this theory has not been vetted though rigorous research, the potential benefits of using biomass within the process may be substantial. At the very least, biomass has very little sulfur and could be a measure to mitigate the emissions of SO_2 from the plant.

The material used during the biomass project at Aurora was unprocessed and, consequently, not uniform. If the biomass material was processed and met some consistency standards there could be a significant measurable gain in efficiency. As such, processed biomass in the form of industrial grade pellets can provide a consistent sizing which would be compatible with the sizing of the stoker coal used at the Chena Power Plant (CPP). The benefit of using an industrial grade pellet is that the anticipated heat content of the pellets are assumed to be upwards of 8300 btu/lb, the moisture content is near 0%, and there is very little sulfur in the fuel. The cons of using an industrial grade biomass pellet is the cost of the fuel which could be as high as $295/ton. At this cost, the use of biomass is not economical. Furthermore, Aurora has not determined whether or not enough raw timber supply is available around the Fairbanks area to accommodate a consistent 15% blend rate. However, if waste biomass material, such as sawdust or bark, from local wood sellers were processed into pellets the raw material could be acquired at a low cost.

5.1 Biomass Economics

Biomass pellets, due to their lack of sulfur, could be used as mitigation for SO_2 emissions. As stated above, the negative aspect of pellets is in the cost and potential lack of access to raw material supply. In order to derive a price point for pellets that would be acceptable as a control technology, a cost effectiveness value of $3,125/ton SO_2 removed is used as a reference. This is a conservative estimate derived by the state in the moderate area SIP.[18] If the 5-year average revenue generated by the plant is divided by the 5-year average coal use we get a value of $79.09 revenue/ton of coal. Pellets have a higher btu/lb content than the coal and pellets have no moisture. To account for this discrepancy, coal heating value is considered after the evaporation of moisture. The energy needed to vaporize free moisture (h_{vap} =1049 btu/lb @ 77F) is multiplied by the moisture fraction of coal to derive the heat content of the coal at 0% moisture. When comparing the wood pellets to coal, the 5-year average heat content (7623 btu/lb) and moisture (29%) is considered. The heating value of coal without moisture is 7304 btu/lb (7623 btu/lb –

Table 13: Biomass and Coal Fuel Revenue/MMBtu

hhv pellets btu/lb	8,300
hhv pellets mmbtu/ton	16.6
hhv coal btu/lb	7,613.05
coal moisture	29%
heat of vaporization of water @ 77F btu/lb	1,049.70
coal btu/lb -vaporized free water	7,304
coal mmbtu/ton -vaporized free water	14.6
pellet coal equivalent	1.14
revenue/ton of coal	$ 79.09
revenue/mmbtu of coal	$ 5.41
revenue/mmbtu of pellets	$ 4.76

[18] ADEC. 2014. Moderate Area State Implementation Plan. Appendix III.D.5.7. pg 132.

1049.7*29/100). Pellets would have a heating content of 8300 btu/lb and no moisture. If the price of the pellets were $84/ton, the cost effectiveness value would be $3,093.04/ton SO_2 removed.

The emission reduction potential using pellets at 15% total fuel loading is 91.24 tons of SO_2 per year. Aurora is actively pursuing this concept; however, running the boiler with 15% biomass has not been tested and a supply of industrial wood pellets at the preferred price has not been identified nor has the availability of the raw material supply been verified.

Table 14: Biomass Cost Effectiveness Calculation

capital investment (hopper modification to auxillary coal feed system)	$300,000.00
loan period (years)	$5.00
interest rate (%)	8%
monthly loan amount	$6,082.92
Annual loan amount	$72,995.04
Burden for 0.5 man equivalent (2016)	$65,520
5-year avg Annual Coal (tons)	221,758.29
5-year avg coal sulfur (%)	0.14%
potential max SO2 (tons/yr)	608.24
Annual pellets (%)	15%
Annual pellets (tons)	29,272.22
emission reduction (tons/yr)	91.24
Cost pellets ($/ton)	$84.00
Annual cost	$2,597,381.16
Annual revenue	$2,315,186.17
annual burden of pellets	$282,194.99
cost/ton removed	3,093.04

6.0 Proposed Alternative BACT – Reduction in Potential to Emit

Aurora proposes to monitor the stack gas emissions out of the common stack. The purpose of the monitoring would be to ensure compliance with an SO_2 emission rate of 190 ppm. Instead of taking a reduction in the sulfur content of the coal or PTE for SO_2 emissions, monitoring the stack gas emissions and maintaining a rolling 30-day average at or under 190 ppm ensures that the plant is not exceeding a certain loading rate equal to 0.25% coal sulfur content. Using the SO_2 emission calculation in the Air Quality Operating permit AQ0315TVP03 Rev. 1, Condition 22.1.c; a stack gas concentration of 7.5% O_2; and adjusting the S% to 0.25 (in this ultimate analysis the S% is 0.26), the SO_2 concentration is 188 ppm as illustrated below:

Figure 1: SO_2 emission calculation

SO2 Concentration PPM = (1.00X 10^6 xmol$_{SO2}$)/(mol$_{SO2}$ +mol$_{CO2}$+mol$_{O2}$+mol$_{N2}$)						
SO2 PPM =						
Where:						
mol SO2 =	[wt% Sfuel,%]/32.06					
mol CO2 =	[wt%Cfuel,%]/12.01					
mol O2 =	MF x [(wt%Nfuel,%]/28.01)+(4.76xmolCO2)+(4.76xmolSO2)+(1.88xmolH2O)-(3.76x[wt%Ofuel,%]/32.00)]					
MF =	[vol%O2,exhaust,%]/(100%-4.76x[vol%O2, exhaust, %])					
mol H2O =	[wt%Hfuel,%]/2.016					
mol N2 =	([wt%Nfuel,%]/28.01)+(3.76xmolSO2)+(3.76xmolCO2)+(1.88xmolH2O)+(3.76xmolO2)-([wt% Ofuel,%]/8.51)					
Constituent	mols in flue gas		Ultimate/proximate analysis (AE08162018)	%weight (dry)	Atomic Mass	Atomic Mass
mol$_{SO2}$	0.007796663		wt% Sulfur$_{fuel}$, %	0.25	Sulphur	32.065
mol$_{CO2}$	5.219382233		wt% Carbon$_{fuel}$, %	62.69	Carbon	12.011
mol$_{H2O}$	2.277011608		wt% Hydrogen$_{fuel}$, %	4.59	Hydrogen	1.0079
mol$_{O2}$	3.098516312		wt% Nitrogen$_{fuel}$, %	0.93	Nitrogen	14.007
mol$_{N2}$	33.05690137		wt% Oxygen$_{fuel}$, %	21.8	Oxygen	15.999
MF	0.116640747			%vol		
			Oxygen exhaust %	7.5		
SO_2 Concentration	188.404394		Source Test Required if exhaust SO_2 Concentration is greater than 500 ppm			

As mentioned, 190 ppm of SO2 emissions on a 30-day rolling average represents an overall PTE reduction from 0.4% sulfur content to 0.25% while still allowing flexibility with respect to coal quality exceeding 0.25% sulfur.

7.0 Precursor Demonstration

As part of the Serious SIP development, states are required to develop Best Available Control Measures for all source sectors that emit $PM_{2.5}$ and the four major precursor gases (e.g., NOx, SO_2, NH_4, and VOC). The analysis specific to the major stationary source is a Best Available Control Technology analysis. Within the rule, if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls for a precursor gas are not required to be implemented.[19] The regulations provide for three kinds of precursor analyses, comprehensive (which consider precursor emissions from all sources in the nonattainment area), Major stationary source (which consider precursor emissions from major sources), and Nonattainment New Source Review (which considers potential precursor emissions from new sources).[20] For each of the first two analyses, there are two varieties available to the state: a concentration-based analysis (compares the precursor contributions to a numerical threshold) and a sensitivity-based analysis which consider other factors to evaluate if reductions in the precursor emissions would significantly reduce $PM_{2.5}$ levels in a nonattainment area.

The ADEC has successfully demonstrated that oxides of nitrogen NOx and VOC are not a significant precursors to the area. The NOx precursor demonstrations included a comprehensive demonstration with a sensitivity based analysis for the community and a Major Stationary Source – concentration based analysis which demonstrated that major sources are not a significant contributor to the nitrate-based particulate formation.[21] The state also conducted a comprehensive, concentration-based analysis for SO_2 and concluded that SO_2 emissions in the NAA contribute 5.4 $\mu g/m^3$ in the Fairbanks area and 4.9 $\mu g/m^3$ of $PM_{2.5}$ in the North Pole area. Since these concentrations exceed the significance threshold of 1.3 $\mu g/m^3$ (now 1.5 $\mu g/m^3$)[22], the ADEC proposes not to conduct a sensitivity-based precursor demonstration nor are they considering a major source precursor demonstration.

EPA's draft precursor guidance recognizes that the significance of a precursors contribution is determined based on the facts and circumstances of the area which include source characteristics such as source type, stack height, and location.[23] The rationale for doing a precursor demonstration fits with the site-specific factors listed in the EPA guidance, namely tall stacks. However, the ADEC and EPA have been resistant to performing or further considering a Major Source precursor demonstration.

Aurora sought a third party opinion (Ramboll Environmental) regarding the possibility of a successful SO_2 precursor demonstration that could demonstrate that major stationary sources are an insignificant part of the contribution to the nonattainment area. According with the EPA's precursor demonstration guidelines, a successful major stationary source precursor demonstration must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ standard (1.5 $\mu g/m^3$). If the 'contribution-based'

[19] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[20] See 40 C.F.R. § 51.1006
[21] ADEC. 2018. Preliminary Draft Precursor Demonstration.
[22] Draft EPA (2016b) guidance recommended 1.3 $\mu g/m^3$ for the $PM_{2.5}$ 24-hour NAAQS as the appropriate threshold to identify insignificant contributions to $PM_{2.5}$ concentrations. A more recent updated technical basis document, EPA (2018) now recommends a threshold for identifying significance of 1.5 $\mu g/m^3$.
[23] EPA's 2016 Draft $PM_{2.5}$ Precursor Demonstration Guidance.

analysis indicates that the impact 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 have only an insignificant impact on lowering $PM_{2.5}$.

Two main hurdles exist to conducting a credible SO_2 precursor demonstration; 1) the large contribution of sulfate by major and minor source contribution to the nonattainment area; and 2) the large under prediction of sulfate mass through the model (CMAQ). In essence, while the SO_2 sources are observed to contribute significantly to the $PM_{2.5}$ nonattainment area, current modeling systems are not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2.

Utilizing the ADEC's information within the Moderate Area SIP, Aurora's third party consult suggests that there is relevant data to suggest major sources are potentially insignificant contributors to the NAA.

> "…data analyses and modeling conducted for the Fairbanks moderate area SIP provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment."[24]

As such, a Major Source SO_2 precursor demonstration must be pursued by the ADEC. It is an undue burden for Aurora and other major sources within the NAA subject to the requirements of control measures (BACT, and more likely MSM) considering that there is data to suggest that major sources could be insignificant. Even though updating models and research into the chemistry of sulfate particulate formation is costly and time consuming, it is due diligence on the agencies part to further elucidate the impact of major sources. Ultimately, Aurora will continue to pursue alternative control measures as proposed within this document under the assumption that the agencies (ADEC and EPA) will continue to vet the sulfate contribution disparity between model and observed values with the perspective of major stationary source contribution.

8.0 Conclusion

The proposed BACT alternatives in this document and accompanying information demonstrate that the ADEC proposed BACT are economically infeasible and do very little to solve the air quality problem in the nonattainment area. EPA, the State of Alaska, as well as the local community understand and agree that the majority of the $PM_{2.5}$ problem in the area is from home heating sources. Aurora contends that requiring the implementation of the ADEC proposed BACT controls would cause the pollution problem to worsen due to our district heat customer's refusal to accept a higher cost heating product and instead switching to fuel oil, or wood burning.

Aurora does not believe ADEC has demonstrated that the point sources, or more specifically Aurora, are contributing to the $PM_{2.5}$ problem in a significant enough way to warrant the need for additional control measures. Aurora believes that a precursor demonstration would prove this assertion one way or another. Aurora believes a precursor demonstration is possible and requests that ADEC and the EPA move forward with conducting a precursor demonstration in parallel with the implementation of the SIP. Should a precursor demonstration show that the point sources do not cross over the significance threshold, all point sources should be released from further compliance with the $PM_{2.5}$ requirements.

Even though Aurora is not convinced that major source emissions exceed the significance threshold for $PM_{2.5}$ within the NAA, Aurora is interested in being a part of the solution to reduce $PM_{2.5}$. Aurora's

[24] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks".2018.

proposed alternative BACT controls are more effective from an environmental perspective and cost substantially less than the ADEC proposed BACT controls. The table below shows the potential amount of SO_2 and $PM_{2.5}$ removed from the NAA by Aurora's proposed alternative BACT.

Table 15: Summary of BACT Alternatives and Potential Emission Reduction

Emissions	SO2 (tpy)	PM 2.5 (tpy)	Qualifying Parameters
District Heating (Current Operating Conditions)	42 tpy at ground level	2 tons at ground level	250,000 – 300,000 mmbtu per year
District Heating (Potential Expansion)	24 tpy at ground level	1 ton at ground level	100 mmbtu/hr expansion potential
Wood Kiln	608.3tpy	33 tons at ground level	8495 cords/yr
Biomass Co-Firing	91.2 tpy	--	15% by fuel heat input from industrial pellets
Potential to emit reduction	38% reduction in PTE (854 tpy)	--	State upper limit of 500 ppm over 3 hours. Proposed 190 ppm as a new PTE
Total Potential Reduction	1,619.5 tpy	36 tpy	

As clearly shown in this table, the environmental benefits from Aurora's proposed alternative BACTs will positively impact the current NAA. Aurora is prepared to move forward with implementing these alternative BACTs as soon as ADEC is able to provide Aurora with the assurance that additional control measures or fees will not be required in order to demonstrate compliance with the PM2.5 regulations for the NAA.

Aurora is committed to continuing to work with ADEC, EPA and the local community in working toward meaningful solutions to the air quality problem in Interior Alaska.

Appendix A (Economic Analysis Spreadsheets – V1)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)?	497	MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560	Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000	lbs/year
Enter the net plant heat input rate (NPHR)	18	MMBtu/MW

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 450 Feet above sea level

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.37	lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80	percent
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	179,783.2	acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	310	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Simpson, Aaron:
April 7, 2016 Source Test

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4	Enter the CEPCI value for 2016 — 584.6 2012 CEPCI
Annual Interest Rate (i)	5.25	Percent
Reagent ($Cost_{reag}$)	1.62	$/gallon for a 50 percent solution of urea
Electricity ($Cost_{elect}$)	0.210	$/kWh
Catalyst cost ($CC_{replace}$)	160.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*
Operator Labor Rate	63.00	$/hour (including benefits)

CEPCI = Chemical Engineering Plant Cost Index

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.80	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year
NOx removal factor (NRF) =	EF/80	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour
Residence Time	$1/V_{space}$	0.03	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	\$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2016 dollars
Balance of Plant Costs (BPC) =	\$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	\$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	\$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	\$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$1,728,014 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$2,921,054 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,723,709 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,728,014 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,921,054 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$4,587 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Is the boiler a fluid-bed boiler?	No
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40 percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05
Concentration of reagent as stored (C_{stored})	50 percent*
Denisty of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	50 percent
Number of days reagent is stored ($t_{storage}$)	30 days
Estimated equipment life	20 Years
Select the reagent used	Urea

Plant Elevation: 450 Feet above sea level

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6	2012 CEPCI
Annual Interest Rate (i)	5.25 Percent		
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*		
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0088 $/gallon*		
Electricity ($Cost_{elect}$)	0.210 $/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x tstorage x 24)/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR)\times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565 in 2016 dollars
Indirect Annual Costs (IDAC) =	$511,631 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$989,197 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166 in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739 in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82 in 2016 dollars
Direct Annual Cost =		$477,565 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$508,837 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$511,631 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$989,197 per year in 2016 dollars
NOx Removed =	318 tons/year
Cost Effectiveness =	$3,107 per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		**TRUE**	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.222	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.24**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection,but not including field installatior
Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284)				
Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)				
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	6.64	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.07	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectioi
VOMP ($/MWh) = Q*T*10	=	$	0.507	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**9.21**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i $(1+i)^n$] / [$(1+i)^n$ - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 30				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0669	=	$	1,383,976	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**2,430,578**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,015,463**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,601,940**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		546	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**8,423**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.122	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.280	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.462**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.876	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,028,350	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,426,798	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	34,042,802	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,238	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,404,280	Engineering and construction management costs
A2 = 10% of BM	=	$	3,404,280	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,404,280	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,255,642**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,609**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,212,782	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,468,425**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,690**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,646,842	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**51,115,267**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**1,859**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.38	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.79**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.06	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.29**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	854,570	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,022,305	CC Manual
Property tax (1% of total capital investment)	=	$	511,153	CC Manual
Insurance (1% of total capital investment)	=	$	511,153	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,420,477	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,319,657**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,499,458**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,716,232**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		702	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**12,408**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.36	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.16	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.283	1.811*K
Aux Power	**M**	**(%)**	**2.098**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.913	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,531,374	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,684,600	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,323,921	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,508,019	Total base cost including retrofit factor
BM ($/kW)	=	$	1,364	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,750,802	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,750,802	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,750,802	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,760,424**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,773**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,438,021	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**51,198,446**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,862**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,119,844.55	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**56,318,290**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,048**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO ($/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	$	28.59	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	13.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.02	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**$**	**43.25**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	1.36	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	=	$	0.31	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	4.41	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	1.02	Variable O&M costs for makeup water
VOMWW ($/MWh) =	=	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**$**	**7.10**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	713,645	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,126,366	CC Manual
Property tax (1% of total capital investment)	=	$	563,183	CC Manual
Insurance (1% of total capital investment)	=	$	563,183	CC Manual
Capital Recovery Factor (CRF) = $[i (1+i)^n] / [(1+i)^n - 1]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 30				
CRF = 0.0669	=	$	3,768,647	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**6,735,024**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**9,634,230**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**8,839,892**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		781	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		773	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**11,440**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix B (Economic Analysis Spreadsheets – V2)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Simpson, Aaron:
No basis was provided to justify a retrofit factor reflecting greater than average difficulty for installation of selective catalytic reduction on the boilers.

High retrofit cost factors may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement).

Aurora: Location of the catalyst, if it has to be installed within a temperature range of 500-800F, would be the top of the boilers just before the economizer and air preheater. It's a titght fit, limited space, asbestos abatement necessary, duct work is complex and

Complete all of the highlighted data fields:

What is the rating at full load capacity (MMBtu/hr)? 497 MMBtu/hr

What is the higher heating value (HHV) of the fuel? 7,560 Btu/lb

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

Enter the sulfur content (%S) = 0.20 percent by weight

Simpson, Aaron:
Typical Gross As Received. http://www.usibelli.com/coal/data-sheet

What is the estimated actual annual fuel consumption? 569,114,000 lbs/year

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	1	0.2	7,560
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the net plant heat input rate (NPHR) 18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 450 Feet above sea level

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 365 days

Number of days the boiler operates (t_{plant}) 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR 0.37 lb/MMBtu

NOx Removal Efficiency (EF) provided by vendor 80 percent

Stoichiometric Ratio Factor (SRF) 0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Simpson, Aaron:
Assuming baseline of 0.5 lb/MMBtu from New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Aurora: Emission Inventory rate based on 2011 source testing.

Simpson, Aaron:
EPA's Air Pollution Control Technology Fact Sheet indicating 70 - 90 percent control. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Number of empty catalyst layers (R_{empty}) 1

Ammonia Slip (Slip) provided by vendor 10 ppm

Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known) UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known) 179,783.2 acfm

Simpson, Aaron:
April 7, 2016 Source Test

Aurora: Source Test dscf = 162098.5.

162098.5 dscf/(1-Bws) = acfm; Bws = 0.0984.

Estimated operating life of the catalyst ($H_{catalyst}$) 24,000 hours

Estimated SCR equipment life 15 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T) 310 °F

Simpson, Aaron:
April 7, 2016 Source Test

Base case fuel gas volumetric flow rate factor (Q_{fuel}) 516 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored}) 50 percent*

Density of reagent as stored (ρ_{stored}) 71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$) 30 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used Urea

Enter the cost data for the proposed SCR:

Desired dollar-year 2016

CEPCI for 2016 536.4 Enter the CEPCI value for 2016 584.6 2012 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i) 5.25 Percent

Reagent ($Cost_{reag}$) 1.62 $/gallon for a 50 percent solution of urea

Electricity ($Cost_{elect}$) 0.210 $/kWh

Simpson, Aaron:
GVEA rates. http://www.gvea.com/rates/rates

Catalyst cost ($CC_{replace}$) 160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

Operator Labor Rate 63.00 $/hour (including benefits)

Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Percent sulfur content for Coal (% weight)	0.31	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Higher Heating Value (HHV) (Btu/lb)	8,730	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/Coal_data.php
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.99	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	80.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	147.11	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	636.77	tons/year	
NOx removal factor (NRF) =	EF/80	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	179,783	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	30.03	/hour	
Residence Time	$1/V_{space}$	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.316	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	5,986.26	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	187	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	215	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	14.7	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	84	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SFR x MW_R)/MW_{NOx} =	101	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	202	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	15,296	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0980

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	365.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$14,132,761	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,348,710	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$3,333,099	in 2016 dollars
Total Capital Investment (TCI) =	$25,758,941	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 270{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$14,132,761 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 490{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 490{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,348,710 in 2016 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 460{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 460{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,333,099 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,193,040 in 2016 dollars
Indirect Annual Costs (IDAC) =	$2,528,093 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$3,721,132 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$128,795 in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$297,936 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$665,284 in 2016 dollars
Annual Catalyst Replacement Cost =		$101,026 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$1,193,040 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,305 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,523,788 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,528,093 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,721,132 per year in 2016 dollars
NOx Removed =	637 tons/year
Cost Effectiveness =	$5,844 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologoies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, repectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	497 MMBtu/hr
What is the higher heating value (HHV) of the fuel?	7,560 Btu/lb
What is the estimated actual annual fuel consumption?	569,114,000 lbs/year
Is the boiler a fluid-bed boiler?	No
Enter the net plant heat input rate (NPHR)	18 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.20 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 7 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	1	0.2	7	7,560	2.79
Lignite	0	0.91	14.3	6,534	1.85

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.37 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	40 percent
Estimated Normalized Stoichiometric Ratio (NSR)	1.05
Concentration of reagent as stored (C_{stored})	50 percent*
Denisty of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	50 percent
Number of days reagent is stored ($t_{storage}$)	30 days
Estimated equipment life	15 Years
Select the reagent used	Urea

Plant Elevation 450 Feet above sea level

*The NSR value of 1.05 is a default value. User should enter actual value, if known.

*The reagent concentration of 50% is a default value. User should enter actual value, if known.

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016	
CEPCI for 2016	536.4 Enter the CEPCI value for 2016	584.6 2012 CEPCI
Annual Interest Rate (i)	5.25 Percent	
Fuel ($Cost_{fuel}$)	2.79 $/MMBtu*	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea*	
Water ($Cost_{water}$)	0.0088 $/gallon*	
Electricity ($Cost_{elect}$)	0.210 $/kWh	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	18.00 $/ton*	

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the the value used and the reference source . . .
Reagent Cost	$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost ($/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for industrial plants is based on 2014 price data compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-861 and 861S, (http://www.eia.gov/electricity/data.cfm#sales).	$0.210/kWh GVEA rates. http://www.gvea.com/rates/rates
Fuel Cost ($/MMBtu)	2.79	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA 923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	18	Average ash disposal costs based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	0.20 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Percent ash content for Coal (% weight)	10.40	Average ash content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7 percent (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet
Higher Heating Value (HHV) (Btu/lb)	11,814	2014 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	7,560 Btu/lb (Typical Gross As Received). Coal data sheet at http://www.usibelli.com/coal/data-sheet

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	497	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	575,888,889	lbs/year	
Actual Annual fuel consumption (Mactual) =		569,114,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.80		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.99	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8657	hours	
NOx Removal Efficiency (EF) =	(Noxin - NOxout)/Noxin =	40.00	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	73.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	318.39	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 450 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea	126	lb/hour
Reagent Usage Rate (m_{sol}) =	mreagent/Csol =	252	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	27	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times tstorage \times 24)$/Reagent Density =	19,121	gallons (storage needed to store a 30 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0980

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electrcity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	5.04	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water$) \times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.11	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1E6)/HHV =	1.05	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars
Total Capital Investment (TCI) =	$6,208,948 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,099,024 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	$2,677,090 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$477,565	in 2016 dollars
Indirect Annual Costs (IDAC) =	$611,129	in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$1,088,694	in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$93,134	in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$372,444	in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,166	in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,739	in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$82	in 2016 dollars
Direct Annual Cost =		$477,565	in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,794	in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$608,335	in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$611,129	in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,088,694	per year in 2016 dollars
NOx Removed =	318	tons/year
Cost Effectiveness =	$3,419	per ton of NOx removed in 2016 dollars

Four Boilers Dry Sorbent Injection System - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Gross Output based on sum of turbines rated size; 20MW, 5MW, and 2.5 MW)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input (Heat Rate is higher because district heating is not included in unit size)
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (Based on source testing 2011)
Type of Coal	E		sub-bituminous	<-- User Input
Particulate Capture	F		Baghouse	<-- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H	(%)	70	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a Baghouse = 80% Milled Trona with Baghouse = 90% Simplified correlation; 70% removal with baghouse. S&L (2013)
Heat Input	J	(Btu/hr)	495,000,000	A*C*1000
NSR	K		1.55	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H)) 1.55 Recommended for a baghouse at a target of 70% removal. S&L (2013)
Trona Feed Rate	M	(ton/hr)	0.28	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	0.185	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	0.92	(A*C)*Ash incoal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2, HHV = 11,000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2, HHV = 8,400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2, HHV = 7,200 <-- User Input (Usibelli Coal: Ash in Coal = 0.07; Boiler Ash Removal = 0.6; HHV = 7,560)
Aux Power	**Q**	**(%)**	**0.20**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	550	<-- User Input (based on Stanley Consultant price reference)
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Operating Labor Rate	U	($/hr)	63	<-- User Input (Labor cost including all benefits [AE 2016])

IPM Model - Updates to Cost and Performance for APC Technologies - Dry Sorbent Injection for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for USEPA https://www.epa.gov/sites/production/files/2015 07/documents/append5_4.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
Base Module (BM) ($) Unmilled Trona = if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona = if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	=	$	14,169,111	Base DSI module includes all equipment from unloading to injection,but not including field installatior
BM ($/kW)	=	$	515	Base module cost per kW
Total Project Cost				
A1 = 20% of BM	=	$	2,833,822	Engineering and construction management costs (CC Manual) (Stanley Consultants)
A2 = 10% of BM	=	$	1,416,911	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	1,416,911	Contractor profit and fees (CC Manual) (Stanley Consultants)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**19,836,755**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs	=	**$**	**721**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	991,838	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**20,828,593**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs	=	**$**	**757**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	=			AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**=**	**$**	**20,682,000**	**Total project cost (Spreadsheet = $20,828,523; Stanley Consultants cost estimate = $20,682,000)**
TPC ($/kW)	=	**$**	**752**	**Total project cost per kW**

Dry Sorbent Injection System - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (2 additional operators)*(2080)*U/(A*1000)	=	$	9.53	Fixed O&M additional operating labor costs (2 additional operators is more realistic)
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	=	$	3.43	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	0.33	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**13.29**	**Total Fixed O&M costs ($/kW yr)**
Variable O&M Cost				
VOMR ($/MWh) = M*R/A	=	$	5.53	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	=	$	2.00	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injectioi
VOMP ($/MWh) = Q*T*10	=	$	0.423	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**=**	**$**	**7.96**	**Total Variable O&M Costs ($/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	219,322	CC Manual
Administrative charges (2% of total capital investment)	=	$	413,640	CC Manual
Property tax (1% of total capital investment)	=	$	206,820	CC Manual
Insurance (1% of total capital investment)	=	$	206,820	CC Manual
Capital Recovery Factor (CRF) = [i (1+i)^n] / [(1+i)^n - 1]				
i = Interest rate (%) 5.25				Revise interest rate to prime (currently 5.25%) per EPA comment
n = Equipment life (years) 15				Reality is 10 years of useful life of the oldside; 30 years control equipment lifetime based on EPA comments on ADEC Prelim. BACT
CRF = 0.0980	=	$	2,026,363	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**3,072,965**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**5,356,087**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**4,914,480**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		70	
TOTAL SO_2 REMOVED, tons	=		456	
SO_2 COST-EFFECTIVENESS, $/ton removed	=	**$**	**10,785**	

Four Boilers Spray Dry Absorber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on total heat input of 497 MMBtu/hour)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0. Site-specific considerations provided by Aurora in 12/22/17 BACT Addendum)
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input (SDA FGD Estimation only valid up to 3lb/MMBtu SO2 Rate)
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous=1.05, Lignite=1.07
Heat Rate Factor	G		1.800	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Lime Rate	K	(ton/hr)	0.101	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 Removal)
Waste Rate	L	(ton/hr)	0.234	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**2.461**	(0.000547*(D^2)+0.00649*D+1.3)*F*G **Should be used for model input**
Makeup Water Rate	N	(1000 gph)	2.874	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) (GVEA Limestone cost)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.htm)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - SDA FGD for SO2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1b_sda_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, and a retrofit difficulty factor of 1.5				
BMR ($) = if(A>600 then (A*92,000) else 566,000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	=	$	13,004,722	Base module absorber island cost
BMF ($) = if(A>600 then (A*48,700) else 300,000*(A^0.716))*B*(D*G)^0.2	=	$	4,268,968	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if(A>600 then (A*129,900) else 799,000*(A^0.716))*B*(F*G)^0.4	=	$	16,587,654	Base module balance of plan costs inlcuding: ID or booster fans, piping, ductwork, electrical, etc.
BM ($) = BMR + BMF + BMB	=	$	33,861,344	Total base module cost including retrofit factor
BM ($/kW)	=	$	1,231	Base module cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,386,134	Engineering and construction management costs
A2 = 10% of BM	=	$	3,386,134	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM	=	$	3,386,134	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**44,019,747**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,601**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,200,987	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**46,220,735**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,681**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	4,622,073	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**50,842,808**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	**=**	**$**	**1,849**	**Total project cost per kW**

Spray Dry Absorber - Chena Power Plant

Direct Annual Costs				
Fixed Operating and Maintenance (O&M) Cost				
FOMO ($/kW yr) = (4 additional operators)*(2080)*T/(A*1000)	=	$	38.12	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	=	$	12.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	$	1.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**=**	**$**	**51.73**	**Total Fixed O&M costs**
Variable O&M Cost				
VOMR ($/MWh) = K*P/A	=	$	0.88	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	=	$	0.25	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	=	$	5.17	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	=	$	0.75	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**=**	**$**	**7.06**	**Total Variable O&M Costs**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	$	853,468	CC Manual
Administrative charges (2% of total capital investment)	=	$	1,016,856	CC Manual
Property tax (1% of total capital investment)	=	$	508,428	CC Manual
Insurance (1% of total capital investment)	=	$	508,428	CC Manual
Capital Recovery Factor (CRF) = [i (1+i)^n] / [(1+i)^n - 1]				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	$	4,981,433	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**$**	**7,868,614**	
TOTAL ANNUALIZED OPERATING COSTS (2012 $)	**=**	**$**	**10,990,629**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 $)	**=**	**$**	**10,084,456**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		90	
TOTAL SO_2 REMOVED, tons	=		586	
SO_2 COST-EFFECTIVENESS, $/ton removed	**=**	**$**	**17,213**	

Four Boilers Wet Scrubber - Chena Power Plant

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	27.5	<-- User Input (Conservative assumption based on a total heat input of 497 MMBtu/hr)
Retrofit Factor	B		1.5	<-- User Input (An "average" retrofit has a factor of 1.0) Sargent and Lundy has a drop down menu for selection of an additional waste water treatment plant facility, but no capital or operational cost are implemented so it is not reproduced here.
Gross Heat Rate	C	(Btu/kWh)	18,000	<-- User Input
SO2 Rate	D	(lb/MMBtu)	0.30	<-- User Input
Type of Coal	E		sub-bituminous	<-- User Input
Coal Factor	F		1.05	Bituminous = 1, Sub-Bituminous = 1.05, Lignite = 1.07
Heat Rate Factor	G		1.8	C/10000
Heat Input	H	(Btu/hr)	495,000,000	A*C*1000
Limestone Rate	K	(ton/hr)	0.13	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	0.236	1.811*K
Aux Power	**M**	**(%)**	**2.079**	(1.05e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	3.908	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	240	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Waste Disposal Cost	Q	($/ton)	30	<-- User Input (https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf)
Aux Power Cost	R	($/kWh)	0.21	<-- User Input (http://www.gvea.com/rates/rates)
Makeup Water Cost	S	($/1000 gal)	7.17	<-- User Input (http://www.newsminer.com/water-rates/article_11a2ba10-c211-562e-8da9-87dd16a7b104.html)
Operating Labor Rate	T	($/hr)	63	Labor cost including all benefits

IPM Model - Updates to Cost and Performance for APC Technologies - Wet FGD for SO2 Control Cost Development Methodology, August 2010, prepared by Sargent & Lundy LLC for US EPA.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_appendix_5-1a_wet_fgd.pdf

Capital Cost Calculation (2012 dollars)				Comments
Includes - Equipment, installation, building, foundations, electrical, minor physical/chemical waste water treatment, and a retrofit difficulty factor of 1.5				
BMR ($) = 550,000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	=	$	12,485,962	Base absorber island cost
BMF ($) = 190,000*(B)*((D*G)^0.3)*(A^0.716)	=	$	2,542,315	Base reagent preparation cost
BMW ($) = 100,000*(B)*((D*G)^0.45)*(A^0.716)	=	$	1,220,076	Base waste handling cost
BMB ($) = 1,010,000*(B)*((F*G)^0.4)*(A^0.716)	=	$	20,968,123	Base balance of plan cost including: ID or booster fans, new wet chimney, piping, ductwork, minor waste water treatment, etc…
BMWW ($) =	=	$	-	Base wastewater treatment facility, beyond minor physical/chemcial treatment
Base Module (BM) ($) = BMR + BMF + BMW + BMB + BMWW	=	$	37,216,477	Total base cost including retrofit factor
BM ($/kW)	=	$	1,353	Base cost per kW
Total Project Cost				
A1 = 10% of BM	=	$	3,721,648	Engineering and construction management costs (CC Manual)
A2 = 10% of BM	=	$	3,721,648	Labor adjustment for 6 x 10 hour shift premium, per diem, etc. (CC Manual)
A3 = 10% of BM	=	$	3,721,648	Contractor profit and fees (CC Manual)
CECC ($) - Excludes Owner's Costs = BM + A1 + A2 + A3	=	**$**	**48,381,420**	Capital, engineering, and construction costs subtotal
CECC ($/kW) - Excludes Owner's Costs =	=	**$**	**1,759**	Capital, engineering, and construction costst subtotal per kW
B1 = 5% of CECC	=	$	2,419,071	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)
TPC ($) - Includes Owners Costs = CECC + B1	=	**$**	**50,800,491**	Total project cost without Allowance for Funds Used During Construction (AFUDC)
TPC ($/kW) - Include Owner's Costs =	=	**$**	**1,847**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	=	$	5,080,049.08	AFUDC (based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**=**	**$**	**55,880,540**	**Total project cost**
TPC ($/kW) - Includes Owner's Costs and AFUDC =	=	**$**	**2,032**	**Total project cost per kW**

Wet Scrubber - Chena Power Plant

Direct Annual Costs				
Fixed O&M Cost				
FOMO (\$/kW yr) = (6 additional operators)*(2080)* T/(A*1000)	=	\$	28.59	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = BM*0.015/(B*A*1000)	=	\$	13.53	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)	=	\$	1.02	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		\$	-	Fixed O&M costs for wastewater treatment facility
FOM (\$/kW yr) = FOMO + FOMM + FOMA + FOMWW	**=**	**\$**	**43.14**	**Total Fixed O&M costs (\$/kW yr)**
Variable O&M Cost				
VOMR (\$/MWh) = K*P/A	=	\$	1.14	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/A	=	\$	0.26	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	=	\$	4.37	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	=	\$	1.02	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	=	\$	-	Variable O&M costs for wastewater treatment facility
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**=**	**\$**	**6.78**	**Total Variable O&M Costs (\$/MW yr)**
Indirect Annual Costs				
Overhead (60% of total labor and material costs)	=	\$	711,875	CC Manual
Administrative charges (2% of total capital investment)	=	\$	1,117,611	CC Manual
Property tax (1% of total capital investment)	=	\$	558,805	CC Manual
Insurance (1% of total capital investment)	=	\$	558,805	CC Manual
Capital Recovery Factor (CRF) = $[\, i\,(1+i)^{n}\,] / [\,(1+i)^{n} - 1\,]$				
i = Interest rate (%) 5.25				
n = Equipment life (years) 15				
CRF = 0.0980	=	\$	5,475,016	CC Manual
TOTAL INDIRECT ANNUAL OPERATING COSTS	**=**	**\$**	**8,422,112**	
TOTAL ANNUALIZED OPERATING COSTS (2012 \$)	**=**	**\$**	**11,241,441**	
Composite CE Index for 2012 (cost year of equation)	=		584.6	
Composite CE Index for 2016 (cost year of review)	=		536.4	
TOTAL ANNUALIZED OPERATING COSTS (2016 \$)	**=**	**\$**	**10,314,589**	
TOTAL UNCONTROLLED SO_2 EMISSIONS, tons	=		651	
SO_2 REMOVAL EFFICIENCY, %	=		99	
TOTAL SO_2 REMOVED, tons	=		644	
SO_2 COST-EFFECTIVENESS, \$/ton removed	=	**\$**	**16,005**	Does not include costs associated with building and maintaining a wastewater treatment facility

Appendix C (Coal Analyses Summary)

Coal Analyses Summary (As Received)					
Year	Report	Coal	HHV	Moisture	Sulfur
Units		(tons)	(btu/lb)	(%)	(%)
2013	A	103,122.35	7,670	27.22	0.15
2013	B	115,917.00	7,599	27.95	0.17
2014	A	117,659.65	7,652	27.89	0.15
2014	B	103,979.45	7,617	27.86	0.14
2015	A	103,904.80	7,599	29.16	0.14
2015	B	120,758.30	7,610	29.02	0.15
2016	A	115,282.20	7,683	31.21	0.12
2016	B	107,687.35	7,604	29.23	0.14
2017	A	106,040.35	7,567	32.20	0.11
2017	B	114,440.00	7,529	32.52	0.10
Weighted average		221,758.29	7,613	29.44	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 6/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	7552	28.06	8.58	36.44	26.93	0.12	TII	V6	6	1,177.90
AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	16906.60	7511.00	28.08	8.95	35.75	27.23	0.14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2013	10	7504	27.93	9.16	34.93	27.98	0.20	T II	T4	4	961.05
AURORA ENERGY LLC	1/3/2013	11	7599	26.87	9.32	35.99	27.83	0.18	P2/STK	C1	6/N	1,000.35
AURORA ENERGY LLC	1/4/2013	9	7685	27.59	8.22	36.39	27.81	0.17	P2/STK	C1	6/N	816.20
AURORA ENERGY LLC	1/5/2013	13	7711	27.47	8.17	36.74	27.63	0.18	P2/STK	C1	6/N	1,263.55
AURORA ENERGY LLC	1/7/2013	11	7612	27.77	8.70	35.41	28.12	0.17	P2/STK	C1	6/N	1,057.50
AURORA ENERGY LLC	1/8/2013	9	7565	26.55	10.25	35.37	27.84	0.17	TII/P2	T4/C1	4/6	858.05
AURORA ENERGY LLC	1/9/2013	12	7584	27.03	9.43	35.53	28.01	0.18	T II/P2	T4/C1	4/6	1,113.90
AURORA ENERGY LLC	1/10/2013	6	7692	25.65	9.78	36.60	27.96	0.17	P2/STK	C1	6/N	562.40
AURORA ENERGY LLC	1/11/2013	13	7507	27.09	10.00	35.86	27.05	0.18	P2/STK	C1	6/N	1,223.50
AURORA ENERGY LLC	1/14/2013	9	7566	26.87	9.70	35.71	27.72	0.16	P2/STK	C1	6/N	872.75
AURORA ENERGY LLC	1/15/2013	14	7632	28.16	8.04	35.42	28.38	0.20	TII	T4	4	1,261.60
AURORA ENERGY LLC	1/16/2013	12	7784	27.66	7.41	36.36	28.57	0.17	TII	T4	4	1,096.85
AURORA ENERGY LLC	1/17/2013	7	7758	27.48	8.08	35.70	28.75	0.19	P2/STK	C1	6/N	645.20
AURORA ENERGY LLC	1/18/2013	11	7788	26.88	7.92	36.52	28.68	0.16	P2/STK	C1	6/N	1,007.45
AURORA ENERGY LLC	1/21/2013	8	7678	26.95	8.63	35.72	28.71	0.17	T II/STK	T4	4/N	737.10
AURORA ENERGY LLC	1/22/2013	13	7709	27.10	8.34	35.59	28.98	0.18	T II/STK	T4	4/N	1,166.85
AURORA ENERGY LLC	1/23/2013	14	7746	27.10	8.39	36.04	28.47	0.17	P2/STK	C1	6/S	1,223.50
AURORA ENERGY LLC	1/25/2013	7	7754	27.88	7.45	36.79	27.89	0.15	P2/STK	C1	6/N	633.50
AURORA ENERGY LLC	1/25/2013	11	7585	26.81	9.72	36.20	27.28	0.15	P2/STK	C1	6/N	994.60
AURORA ENERGY LLC	1/28/2013	9	7484	26.40	11.09	35.58	26.94	0.15	P2/STK	C1	6/S	807.55
AURORA ENERGY LLC	1/29/2013	11	7691	26.62	9.22	36.11	28.05	0.15	P2/STK	C1	6/S	994.45
AURORA ENERGY LLC	1/30/2013	13	7482	28.23	9.21	35.05	27.52	0.16	P2/STK	C1	6/S	1,150.80
AURORA ENERGY LLC	1/31/2013	10	7460	26.87	10.25	34.89	27.99	0.15	TII/P2	T3/C1	3/6	920.60
AURORA ENERGY LLC	2/1/2013	8	7529	28.24	9.08	35.07	27.61	0.14	TII	T3	3	763.65
AURORA ENERGY LLC	2/4/2013	7	7545	28.48	8.71	34.47	28.34	0.13	TII	T3	3	629.95
AURORA ENERGY LLC	2/5/2013	11	7463	28.30	9.56	34.22	27.92	0.14	T II	T3	3	1,015.15
AURORA ENERGY LLC	2/7/2013	8	7491	28.60	8.93	34.76	27.72	0.13	P2/TII	C1/T3	6/3	755.05
AURORA ENERGY LLC	2/8/2013	12	7637	27.97	8.09	36.09	27.86	0.14	P2/TII	C1/T3	6/3	1,113.25
AURORA ENERGY LLC	2/9/2013	12	7740	26.73	8.61	37.24	27.42	0.14	P2	C1	6	1,102.05
AURORA ENERGY LLC	2/11/2013	9	7506	26.87	9.55	35.20	28.38	0.16	T II/P2	T3/C1	3/6	848.85

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Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	2/12/2013	15	7649	27.94	8.20	35.09	28.77	0.15	T II	T3	3	1,378.10
AURORA ENERGY LLC	2/13/2013	21	7556	27.99	9.13	34.51	28.38	0.15	T II	T3	3	1,914.10
AURORA ENERGY LLC	2/14/2013	8	7819	26.40	8.38	36.31	28.91	0.14	P2/STK	C1	6/N	701.80
AURORA ENERGY LLC	2/15/2013	15	7437	27.31	10.59	34.59	27.51	0.15	P2/STK	C1	6/S	1,300.35
AURORA ENERGY LLC	2/18/2013	9	7616	27.77	8.69	34.75	28.80	0.14	TII	T3	3	852.10
AURORA ENERGY LLC	2/19/2013	5	8065	26.73	6.36	37.32	29.59	0.13	P2/STK	C1	6/S	448.60
AURORA ENERGY LLC	2/20/2013	18	7824	27.32	7.48	37.11	28.09	0.15	P2/STK	C1	6/S	1,648.60
AURORA ENERGY LLC	2/21/2013	7	7607	26.43	10.17	36.29	27.11	0.15	P2/STK	C1	6/S	615.40
AURORA ENERGY LLC	2/22/2013	15	7510	28.05	9.42	35.26	27.28	0.14	TII	T3	3	1,390.45
AURORA ENERGY LLC	2/25/2013	9	7697	28.21	7.72	34.80	29.27	0.14	TII	T3	3	817.70
AURORA ENERGY LLC	2/26/2013	14	7588	28.23	8.43	35.08	28.26	0.14	TII/P2	T3/C1	3/6	1,275.05
AURORA ENERGY LLC	2/28/2013	17	7872	27.40	6.91	37.27	28.43	0.15	P2/STK	C1	6/S	1,587.05
AURORA ENERGY LLC	3/4/2013	11	7508	26.13	11.00	35.23	27.65	0.15	P2/TII	C1/T3	6/3	1,033.95
AURORA ENERGY LLC	3/5/2013	11	7682	26.99	8.13	36.34	28.55	0.14	P2/STK	C1	6/S	959.30
AURORA ENERGY LLC	3/6/2013	14	7648	27.25	7.96	36.56	28.23	0.15	P2/STK	C1	6/S	1,302.85
AURORA ENERGY LLC	3/7/2013	7	7717	26.40	8.27	37.82	27.53	0.15	P2/STK	C1	6/S	619.15
AURORA ENERGY LLC	3/8/2013	6	7469	26.55	9.86	37.18	26.41	0.16	P2/STK	C1	6/S	538.30
AURORA ENERGY LLC	3/11/2013	11	7857	27.02	7.45	37.34	28.20	0.15	P2/STK	C1	6/S	1,016.00
AURORA ENERGY LLC	3/12/2013	13	7868	26.99	7.27	37.32	28.43	0.14	P2/STK	C1	6/S	1,200.55
AURORA ENERGY LLC	3/13/2013	18	7437	28.70	8.86	35.07	27.37	0.14	P2/STK	C1	6/S	1,586.50
AURORA ENERGY LLC	3/15/2013	7	7253	25.91	13.37	35.02	25.70	0.14	P2/STK	C1	6/S	652.45
AURORA ENERGY LLC	3/19/2013	11	7570	26.44	10.41	36.24	26.91	0.16	P2/STK	C1	6/S	1,034.15
AURORA ENERGY LLC	3/19/2013	8	7723	26.43	9.14	36.80	27.63	0.14	P2/STK	C1	6/S	734.00
AURORA ENERGY LLC	3/20/2013	11	7812	26.67	8.36	36.58	28.40	0.15	P2/STK	C1	6/S	1,058.60
AURORA ENERGY LLC	3/21/2013	3	7805	26.35	8.46	36.75	28.44	0.15	P2/STK	C1	6/S	264.35
AURORA ENERGY LLC	3/22/2013	8	7580	26.59	10.17	36.01	27.24	0.15	P2/STK	C1	6/S	747.60
AURORA ENERGY LLC	3/25/2013	6	7835	26.61	7.98	37.07	28.35	0.15	P2/STK	C1	6/S	545.80
AURORA ENERGY LLC	3/26/2013	10	7873	26.37	7.94	37.21	28.48	0.16	P2/STK	C1	6/S	911.95
AURORA ENERGY LLC	3/27/2013	11	7633	26.67	9.68	35.80	27.86	0.16	P2/STK	C1	6/S	1,011.95
AURORA ENERGY LLC	3/28/2013	4	7776	26.70	8.29	37.09	27.93	0.15	P2/STK	C1	6/S	363.85
AURORA ENERGY LLC	4/1/2013	6	7964	26.30	7.22	37.59	28.89	0.15	P2/STK	C1	6/S	527.90
AURORA ENERGY LLC	4/2/2013	11	[illegible]	[illegible]	[illegible]	[illegible]	29.16	0.15	P2/STK	C1	6/S	993.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	4/3/2013	10	7812	27.29	7.75	36.64	28.33	0.14	P2/STK	C1	6/S	935.20
AURORA ENERGY LLC	4/4/2013	5	7779	26.72	8.53	36.84	27.92	0.14	P2/STK	C1	6/S	458.50
AURORA ENERGY LLC	4/5/2013	9	7866	26.26	8.67	36.80	28.28	0.15	P2/STK	C1	6/N	855.30
AURORA ENERGY LLC	4/8/2013	10	7363	27.30	11.58	34.23	26.89	0.16	P2/JDRC	C1/C13	6/3	934.30
AURORA ENERGY LLC	4/9/2013	14	7381	29.34	8.61	35.20	26.86	0.14	TII	V6	6	1,269.45
AURORA ENERGY LLC	4/11/2013	10	7736	28.34	7.26	36.44	27.97	0.15	TII	V6	6	885.25
AURORA ENERGY LLC	4/11/2013	6	7591	28.62	7.89	36.55	26.95	0.14	TII	V6	6	556.70
AURORA ENERGY LLC	4/16/2013	11	7286	29.40	11.50	32.67	26.44	0.15	JD/GRP	C13	3/C	1,062.00
AURORA ENERGY LLC	4/16/2013	10	7385	29.01	10.61	33.14	27.25	0.17	JDRC	C13	3	939.50
AURORA ENERGY LLC	4/18/2013	8	7746	27.55	7.98	36.17	28.31	0.15	T II	V6	6	730.15
AURORA ENERGY LLC	4/20/2013	8	7783	26.84	9.01	35.88	28.28	0.16	T II/STK	V6	6/W	750.40
AURORA ENERGY LLC	4/22/2013	7	7659	27.90	8.10	36.27	27.74	0.16	T II/STK	V6	6/W	657.70
AURORA ENERGY LLC	4/23/2013	8	7706	27.47	8.38	36.53	27.61	0.16	T II/STK	V6	6/W	741.05
AURORA ENERGY LLC	4/25/2013	9	7589	27.83	8.91	36.03	27.24	0.15	T II	V6	6	856.65
AURORA ENERGY LLC	4/25/2013	7	7505	26.90	10.26	36.16	26.69	0.14	TII	V6	6	640.30
AURORA ENERGY LLC	4/26/2013	8	7601	27.54	8.54	37.23	26.69	0.15	TII	V6	6	746.30
AURORA ENERGY LLC	4/29/2013	10	7495	28.32	8.82	35.78	27.09	0.14	T II	V6	6	915.65
AURORA ENERGY LLC	4/30/2013	12	7123	27.64	12.55	34.60	25.21	0.14	T II	V6	6	1,130.20
AURORA ENERGY LLC	5/1/2013	12	7962	24.90	11.11	35.05	28.95	0.17	GRP/STK		M/N	1,238.65
AURORA ENERGY LLC	5/2/2013	10	7815	25.21	11.77	34.52	28.51	0.17	GRP/STK		M/S	940.15
AURORA ENERGY LLC	5/3/2013	7	7574	25.05	13.91	33.39	27.66	0.18	GRP/STK		M/S	670.35
AURORA ENERGY LLC	5/3/2013	13	8042	24.57	11.80	34.49	29.14	0.18	GRP/STK		M/S	1,223.00
AURORA ENERGY LLC	5/6/2013	3	8200	23.89	10.98	34.73	30.41	0.19	GRP/STK		M/N	278.80
AURORA ENERGY LLC	5/20/2013	8	7876	26.05	9.72	36.04	28.19	0.16	GRP/STK		M/N	765.10
AURORA ENERGY LLC	5/21/2013	16	8437	24.71	8.98	35.53	30.78	0.18	GRP/STK		M/N	1,459.45
AURORA ENERGY LLC	5/23/2013	10	8746	23.37	8.77	35.33	32.54	0.18	GRP		M	954.30
AURORA ENERGY LLC	5/23/2013	11	8414	24.03	9.96	34.57	31.45	0.17	GRP		M	1,064.60
AURORA ENERGY LLC	5/27/2013	9	8508	23.93	9.27	35.49	31.31	0.18	GRP/STK		M/N	819.70
AURORA ENERGY LLC	5/28/2013	12	8514	24.06	9.27	35.30	31.38	0.18	GRP/STK		M/N	1,151.15
AURORA ENERGY LLC	5/30/2013	10	7619	27.91	8.56	36.48	27.05	0.13	T II	V6	6	956.70
AURORA ENERGY LLC	6/3/2013	8	7490	28.62	8.57	35.96	26.86	0.13	TII	V6	6	741.40
AURORA ENERGY LLC	6/4/2013	13	7552	28.08	8.58	36.44	26.93	0.12	TII	V6	6	1,177.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/13 to 6/30/13

AURORA ENERGY LLC	6/6/2013	14	7303	28.45	10.15	34.89	26.51	0.14	T II	V6	6	1,308.40
AURORA ENERGY LLC	6/10/2013	16	7414	28.08	9.77	35.36	26.78	0.13	TII	V6	6	1,513.40
AURORA ENERGY LLC	6/13/2013	19	7528	27.82	9.38	35.66	27.15	0.15	T II	V6	6	1,749.25
AURORA ENERGY LLC	6/17/2013	7	7626	27.41	9.41	35.51	27.67	0.15	T II	V6	6	656.20
AURORA ENERGY LLC	6/18/2013	23	7682	28.49	7.14	36.88	27.50	0.14	T II	V6	6	2,079.85
AURORA ENERGY LLC	6/20/2013	26	7386	27.49	10.19	35.92	26.40	0.13	T II	V6	6	2,365.55
AURORA ENERGY LLC	6/24/2013	14	7325	28.36	9.89	35.53	26.23	0.14	TII	V6	6	1,289.20
AURORA ENERGY LLC	6/26/2013	13	7522	28.53	8.56	34.56	28.35	0.19	T II	U4	4	1,202.85
AURORA ENERGY LLC	6/28/2013	19	7715	27.62	7.89	36.01	28.49	0.15	TII	U4	4	1,751.50
AURORA ENERGY LLC	6/28/2013	12	7593	28.46	7.84	35.39	28.32	0.14	TII	U4	4	1,071.10

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103122.35	7670.00	27.22	9.05	35.76	27.98	0.15

This analysis is representative of the coal shipped using sulfur standard ASTM D4239-12

Coleen Thompson

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2013	7	7360	26.50	11.80	35.40	26.30	0.15	TBR	C1	6	652.55
AURORA ENERGY LLC	7/2/2013	21	7675	26.40	9.51	36.33	27.77	0.15	TBR	C1	6	1,961.70
AURORA ENERGY LLC	7/5/2013	23	7565	27.34	9.39	34.94	28.34	0.19	T II	U4	4	2,171.90
AURORA ENERGY LLC	7/8/2013	10	7538	28.53	8.36	34.23	28.88	0.19	TII	U4	4	917.50
AURORA ENERGY LLC	7/9/2013	29	7645	28.51	7.49	35.44	28.57	0.16	T II	U4	4	2,700.95
AURORA ENERGY LLC	7/11/2013	13	7502	28.50	8.82	35.62	27.06	0.18	TBR	C1	6	1,224.95
AURORA ENERGY LLC	7/15/2013	12	7485	29.53	7.66	35.01	27.81	0.19	TII	U4	4	1,067.35
AURORA ENERGY LLC	7/16/2013	11	7317	27.95	10.29	34.12	27.68	0.25	T II	U4	4	1,019.50
AURORA ENERGY LLC	7/22/2013	11	7609	28.80	7.97	34.86	28.37	0.18	TII	U4	4	1,018.45
AURORA ENERGY LLC	7/24/2013	25	7467	28.43	8.50	34.68	28.41	0.19	T II	U4	4	2,303.20
AURORA ENERGY LLC	7/25/2013	13	7416	28.52	9.36	34.76	27.37	0.20	TII	U4	4	1,239.20
AURORA ENERGY LLC	7/29/2013	9	7339	29.30	9.16	33.88	27.67	0.20	T II	U4	4	836.20
AURORA ENERGY LLC	8/1/2013	27	7749	27.87	8.65	34.52	28.97	0.15	JR/GRP	C13	4/M	2,483.15
AURORA ENERGY LLC	8/5/2013	10	7833	27.43	9.00	34.23	29.35	0.17	JD/GRP	C13	4/M	948.40
AURORA ENERGY LLC	8/6/2013	18	7752	29.20	7.09	34.40	29.31	0.14	JR/GRP	C13	4/M	1,657.00
AURORA ENERGY LLC	8/8/2013	12	7737	28.58	7.91	34.30	29.22	0.14	JR/GRP	C13	4/M	1,172.25
AURORA ENERGY LLC	8/8/2013	16	7648	28.65	8.33	34.49	28.53	0.13	JR/GRP	C13	4/M	1,524.25
AURORA ENERGY LLC	8/9/2013	12	7552	28.48	8.20	35.34	27.99	0.20	TII	U4	4	1,085.70
AURORA ENERGY LLC	8/12/2013	7	7610	28.79	7.51	34.66	29.05	0.16	TII	U4	4	657.40
AURORA ENERGY LLC	8/13/2013	17	7503	29.40	8.11	34.39	28.11	0.15	JR/T II	C13/U4	4/4	1,550.05
AURORA ENERGY LLC	8/19/2013	9	7696	28.53	8.03	34.46	29.00	0.16	JR	C13	4	834.85
AURORA ENERGY LLC	8/20/2013	17	7764	28.71	7.65	34.86	28.79	0.14	JR/GRP	C13	4/M	1,569.00
AURORA ENERGY LLC	8/22/2013	11	8309	24.18	10.01	34.82	31.00	0.20	GRP/STK		M/N	1,008.60
AURORA ENERGY LLC	8/22/2013	15	8288	24.11	9.99	35.32	30.58	0.17	GRP/STK		M/N	1,412.05
AURORA ENERGY LLC	8/26/2013	5	7656	27.01	10.63	33.80	28.57	0.19	T II/GRP	U3	3/M	491.15
AURORA ENERGY LLC	8/27/2013	12	7557	27.38	10.91	33.44	28.26	0.15	T II/GRP	U3	3/M	1,141.90
AURORA ENERGY LLC	8/28/2013	10	7705	27.60	9.20	34.46	28.74	0.14	T II/GRP	U3	3/M	905.40
AURORA ENERGY LLC	8/29/2013	12	7822	26.89	10.18	34.14	28.79	0.15	TII/GRP	U3	3/M	1,149.70
AURORA ENERGY LLC	9/3/2013	11	7996	26.39	10.28	34.01	29.33	0.16	TII/GRP	U3	3/M	1,048.10
AURORA ENERGY LLC	9/5/2013	10	7654	26.76	10.82	33.81	28.61	0.15	T II/GRP	U3	3/M	935.45

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	9/5/2013	12	7566	28.02	8.70	34.71	28.58	0.12	T II	U3	3	1,051.50
AURORA ENERGY LLC	9/7/2013	9	7584	28.16	8.73	35.10	28.01	0.12	T II	U3	3	808.00
AURORA ENERGY LLC	9/9/2013	5	7525	28.89	8.44	34.02	28.66	0.13	T II	U3	3	479.85
AURORA ENERGY LLC	9/11/2013	20	6894	29.54	12.49	32.88	25.09	0.13	JR	C13	3	1,938.20
AURORA ENERGY LLC	9/13/2013	20	7578	27.99	8.74	34.77	28.50	0.13	TII/STK	U3	3/N	1,900.70
AURORA ENERGY LLC	9/16/2013	8	7507	27.68	9.36	34.53	28.43	0.12	TII	U3	3	769.35
AURORA ENERGY LLC	9/18/2013	12	7474	28.91	8.87	34.24	27.99	0.13	T II	U3	3	1,134.85
AURORA ENERGY LLC	9/19/2013	18	7447	28.38	9.45	34.11	28.06	0.12	T II	U3	3	1,756.50
AURORA ENERGY LLC	9/20/2013	15	7567	28.36	8.52	34.37	28.75	0.12	T II	U3	3	1,459.60
AURORA ENERGY LLC	9/24/2013	21	7503	27.57	9.98	35.65	26.81	0.15	TBR	C1	6	2,034.85
AURORA ENERGY LLC	9/25/2013	15	7615	26.60	9.92	36.33	27.16	0.15	TBR	C1	6	1,425.25
AURORA ENERGY LLC	9/26/2013	13	7626	26.57	9.47	37.08	26.88	0.15	TBR	C1	6	1,261.65
AURORA ENERGY LLC	9/30/2013	6	7556	26.97	10.47	35.62	26.95	0.15	TBR	C1	6	572.95
AURORA ENERGY LLC	10/2/2013	8	7354	27.62	11.21	33.98	27.20	0.18	TBR	C1	6	758.30
AURORA ENERGY LLC	10/7/2013	11	7515	27.82	9.13	34.36	28.69	0.16	T II	V4	4	1,009.45
AURORA ENERGY LLC	10/10/2013	23	7298	28.57	10.30	33.77	27.36	0.15	T II	V4	4	2,203.90
AURORA ENERGY LLC	10/11/2013	17	7295	28.25	10.17	34.26	27.32	0.21	TII	V4	4	1,618.40
AURORA ENERGY LLC	10/15/2013	13	7770	27.43	8.67	34.47	29.43	0.21	T II	V4	4	1,250.95
AURORA ENERGY LLC	10/16/2013	9	7622	28.16	8.19	34.71	28.94	0.18	T II	V4	4	834.60
AURORA ENERGY LLC	10/17/2013	16	7560	28.73	7.77	34.73	28.78	0.19	T II	V4	4	1,448.90
AURORA ENERGY LLC	10/18/2013	13	7582	27.73	7.91	35.43	28.93	0.18	TII	V4	4	1,209.15
AURORA ENERGY LLC	10/21/2013	15	7584	27.84	9.19	34.45	28.53	0.20	T II	V4	4	1,476.80
AURORA ENERGY LLC	10/22/2013	13	7492	28.05	9.43	34.58	27.95	0.20	T II	V4	4	1,280.80
AURORA ENERGY LLC	10/23/2013	18	7557	28.26	8.52	34.70	28.52	0.20	T II	V4	4	1,756.85
AURORA ENERGY LLC	10/26/2013	14	7539	27.86	9.52	34.75	27.88	0.20	T II/T II	V4/W4	4/4	1,307.25
AURORA ENERGY LLC	10/28/2013	13	7536	27.75	9.19	34.92	28.15	0.20	TII	W4	4	1,171.30
AURORA ENERGY LLC	10/29/2013	12	7871	28.27	5.87	35.86	30.00	0.14	Bdl	Bx	3	1,070.25
AURORA ENERGY LLC	10/30/2013	13	7644	27.59	8.16	34.73	29.52	0.12	Bdl	C4	3	1,251.70
AURORA ENERGY LLC	11/2/2013	17	7709	28.33	7.68	35.49	28.50	0.15	T II	W4	4	1,561.60
AURORA ENERGY LLC	11/4/2013	9	7745	28.25	7.16	35.46	29.13	0.17	Bdl	C4	3	828.45
AURORA ENERGY LLC	11/5/2013	11	7603	28.42	8.04	34.70	28.84	0.16	T II	W4	4	1,007.45
AURORA ENERGY LLC	11/6/2013	14	7565	28.35	8.34	34.72	28.52	0.18	T II	W4	4	1,280.20

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	11/7/2013	11	7677	28.65	6.91	35.74	28.70	0.13	T II	W4	4	939.25
AURORA ENERGY LLC	11/8/2013	8	7833	27.17	7.05	36.48	29.30	0.13	BdI	C4	3	726.25
AURORA ENERGY LLC	11/12/2013	13	7498	28.03	9.12	34.66	28.19	0.21	TII	W4	4	1,230.50
AURORA ENERGY LLC	11/13/2013	17	7622	28.11	7.98	34.84	29.08	0.20	T II	W4	4	1,615.85
AURORA ENERGY LLC	11/14/2013	15	7466	27.50	9.91	34.21	28.39	0.21	TII	W4	4	1,368.50
AURORA ENERGY LLC	11/15/2013	12	7512	28.08	8.72	34.44	28.78	0.20	TII	W4	4	1,137.60
AURORA ENERGY LLC	11/18/2013	12	7497	27.70	9.39	34.26	28.65	0.21	TII	W4	4	1,169.75
AURORA ENERGY LLC	11/19/2013	13	7183	26.91	12.26	33.66	27.18	0.23	TII	W4	4	1,238.50
AURORA ENERGY LLC	11/20/2013	10	7196	27.55	12.16	33.17	27.13	0.25	T II	W4	4	928.10
AURORA ENERGY LLC	11/21/2013	3	7305	27.84	11.04	33.48	27.65	0.25	T II	W4	4	282.10
AURORA ENERGY LLC	11/22/2013	9	7444	28.14	9.57	34.53	27.77	0.22	TII	W4	4	853.00
AURORA ENERGY LLC	11/23/2013	25	7557	28.84	7.91	34.72	28.54	0.19	TII	W4	4	2,370.10
AURORA ENERGY LLC	11/26/2013	3	7521	28.65	8.47	34.71	28.18	0.20	TII	W4	4	292.95
AURORA ENERGY LLC	11/27/2013	14	7453	28.74	9.06	34.31	27.89	0.20	TII	W4	4	1,322.45
AURORA ENERGY LLC	11/29/2013	10	7658	27.34	8.86	34.71	29.09	0.16	TII/STK	W4	3/N	946.40
AURORA ENERGY LLC	12/2/2013	17	7630	28.09	8.37	34.99	28.56	0.18	TII	W4	4	1,494.70
AURORA ENERGY LLC	12/3/2013	10	7595	28.49	8.08	34.80	28.63	0.20	T II	W4	4	869.90
AURORA ENERGY LLC	12/4/2013	10	7734	27.36	7.78	35.11	29.76	0.17	T II	W4	4	904.75
AURORA ENERGY LLC	12/5/2013	8	7810	27.74	6.95	35.21	30.10	0.13	BdI	C4	3	763.85
AURORA ENERGY LLC	12/9/2013	11	7711	27.99	7.91	34.53	29.57	0.13	BdI/TII	C4/W4	3/4	1,063.85
AURORA ENERGY LLC	12/10/2013	13	7739	27.62	7.73	34.74	29.92	0.13	BdI	C4	3	1,275.10
AURORA ENERGY LLC	12/11/2013	9	7674	27.46	8.60	34.24	29.71	0.13	BdI	C4	3	881.40
AURORA ENERGY LLC	12/13/2013	3	7696	27.89	8.39	34.21	29.51	0.11	BdI/STK	C4	3/N	286.75
AURORA ENERGY LLC	12/16/2013	9	7702	27.46	8.54	34.06	29.94	0.12	BdI	C4	3	852.80
AURORA ENERGY LLC	12/17/2013	8	7800	27.48	7.89	34.58	30.05	0.13	BdI	C4	4	776.85
AURORA ENERGY LLC	12/18/2013	12	7960	27.33	6.37	35.46	30.85	0.13	BdI	C4	3	1,176.55
AURORA ENERGY LLC	12/19/2013	10	7856	28.26	6.73	34.92	30.10	0.12	BdI	C4	3	966.55
AURORA ENERGY LLC	12/20/2013	7	7801	27.63	7.58	34.88	29.92	0.13	BdI/STK	C4	3/N	669.90
AURORA ENERGY LLC	12/23/2013	15	7802	28.04	7.12	34.75	30.09	0.12	BdI/STK	C4	3/N	1,473.00
AURORA ENERGY LLC	12/24/2013	15	7676	27.81	8.37	34.17	29.65	0.15	BdI/STK	C4	3/N	1,459.65
AURORA ENERGY LLC	12/27/2013	5	7632	28.24	8.14	35.09	28.53	0.19	TII	X4	4	431.00
AURORA ENERGY LLC	12/27/2013	6	7575	28.27	8.62	34.41	27.70	0.22	TII	X4	4	547.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/13 to 12/31/13

AURORA ENERGY LLC	12/29/2013	27	7744	27.93	7.68	35.17	29.23	0.17	TII	X4	4	2,307.45
AURORA ENERGY LLC	12/30/2013	10	7520	27.94	9.09	34.77	28.20	0.22	T II	X4	4	942.95
AURORA ENERGY LLC	12/31/2013	8	7602	27.77	8.55	34.81	28.87	0.22	T II	X4	4	744.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115917.70	7599.00	27.95	8.81	34.72	28.53	0.17

This analysis is representative of the coal shipped using sulfur standard ASTM D4239-12

Colleen Thompson
1-3-14

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2014	15	7592	27.80	8.87	34.55	28.78	0.20	T II	X4	4	1,370.90
AURORA ENERGY LLC	1/3/2014	15	7615	29.16	7.32	35.00	28.52	0.17	TII	X4	4	1,440.35
AURORA ENERGY LLC	1/6/2014	8	7633	28.42	7.70	34.85	29.03	0.16	T II	X4	4	779.40
AURORA ENERGY LLC	1/7/2014	12	7642	28.93	7.31	34.80	28.97	0.17	TII	X4	4	1,137.10
AURORA ENERGY LLC	1/8/2014	13	7615	28.31	8.20	34.76	28.74	0.19	T II	X4	4	1,229.35
AURORA ENERGY LLC	1/9/2014	11	7538	28.03	8.94	34.41	28.63	0.23	T II	X4	4	1,070.75
AURORA ENERGY LLC	1/10/2014	13	7571	28.86	8.02	34.63	28.49	0.18	TII	X4	4	1,216.15
AURORA ENERGY LLC	1/13/2014	10	7453	27.84	9.86	34.82	27.48	0.22	TII	X4	4	984.25
AURORA ENERGY LLC	1/14/2014	11	7489	28.42	8.99	34.32	28.27	0.22	Bdl	C4	3	1,031.80
AURORA ENERGY LLC	1/15/2014	8	7608	28.12	8.69	34.32	28.87	0.20	T II	X4	4	756.60
AURORA ENERGY LLC	1/16/2014	13	7588	28.25	8.55	34.40	28.80	0.20	T II	X4	4	1,251.05
AURORA ENERGY LLC	1/18/2014	16	7679	29.63	6.32	34.82	29.24	0.14	TII	X4	4	1,478.00
AURORA ENERGY LLC	1/20/2014	10	7735	28.53	7.06	34.71	29.71	0.16	T II	X4	4	953.85
AURORA ENERGY LLC	1/21/2014	9	7833	28.40	6.48	34.96	30.17	0.13	Bdl	C4	3	805.85
AURORA ENERGY LLC	1/22/2014	12	7767	27.95	7.35	34.72	29.99	0.13	Bdl	C4	3	1,168.20
AURORA ENERGY LLC	1/23/2014	3	7759	28.53	7.30	34.21	29.97	0.13	Bdl	C4	3	293.50
AURORA ENERGY LLC	1/27/2014	9	7379	28.65	9.78	33.16	28.41	0.12	Bdl/JR	C4/C13	3/3	853.10
AURORA ENERGY LLC	1/28/2014	9	7700	28.25	7.82	34.50	29.43	0.15	Bdl/JR	C4/C13	3/3	810.95
AURORA ENERGY LLC	1/29/2014	10	7721	28.70	7.00	34.48	29.82	0.14	Bdl/STK	C4	3/N	917.25
AURORA ENERGY LLC	1/30/2014	15	7737	28.41	7.34	34.81	29.44	0.13	Bdl	C4	3	1,357.75
AURORA ENERGY LLC	1/31/2014	22	7529	29.01	8.13	33.66	29.21	0.12	Bdl	C4	3	2,046.90
AURORA ENERGY LLC	2/3/2014	19	7560	28.92	8.26	33.56	29.26	0.14	Bdl	C4	3	1,809.10
AURORA ENERGY LLC	2/4/2014	12	7527	29.18	8.14	33.53	29.14	0.13	Bdl/ T II	C4/X3	3/3	1,138.90
AURORA ENERGY LLC	2/5/2014	6	7533	28.73	8.62	34.00	28.66	0.13	TII	X3	3	549.45
AURORA ENERGY LLC	2/6/2014	9	7582	28.26	8.89	33.92	28.93	0.12	T II	X3	3	833.35
AURORA ENERGY LLC	2/10/2014	11	7548	28.78	8.49	33.65	29.08	0.13	T II	X3	3	997.40
AURORA ENERGY LLC	2/12/2014	13	7669	28.02	8.03	34.85	29.10	0.13	T II	X3	3	1,178.00
AURORA ENERGY LLC	2/12/2014	8	7568	27.51	9.42	34.40	28.68	0.12	T II	X3	3	735.35
AURORA ENERGY LLC	2/13/2014	12	7810	26.92	8.17	35.24	29.67	0.19	Bdl	A	4	1,085.25
AURORA ENERGY LLC	2/15/2014	10	7841	26.99	7.79	36.16	29.07	0.21	Bdl	A	4	964.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	2/17/2014	8	7821	26.21	8.59	36.19	29.02	0.26	Bdl	A	4	771.90
AURORA ENERGY LLC	2/18/2014	12	7857	26.05	8.45	35.90	29.61	0.23	Bdl	A	4	1,099.50
AURORA ENERGY LLC	2/19/2014	16	7803	26.19	8.75	35.91	29.15	0.21	Bdl/STK	A	4/N	1,524.75
AURORA ENERGY LLC	2/20/2014	7	7738	26.33	9.11	35.75	28.82	0.20	Bdl/STK	A	4/N	670.45
AURORA ENERGY LLC	2/21/2014	18	7702	26.91	8.70	35.77	28.63	0.20	Bdl/STK	A	4/N	1,716.05
AURORA ENERGY LLC	2/24/2014	13	7721	27.34	8.35	35.25	29.07	0.19	Bdl/STK	A	4/N	1,244.25
AURORA ENERGY LLC	2/25/2014	14	7663	27.53	8.50	34.81	29.15	0.15	TII/Bdl	X3/A	3/4	1,314.15
AURORA ENERGY LLC	2/27/2014	18	7704	27.80	7.88	35.13	29.20	0.14	T II	X3	3	1,743.25
AURORA ENERGY LLC	2/28/2014	19	7519	28.26	8.83	34.59	28.33	0.13	Bdl/T II	A/X3	4/3	1,856.75
AURORA ENERGY LLC	3/3/2014	11	7539	28.91	8.17	33.90	29.03	0.11	TII/Bdl	X3/A	3/4	1,078.75
AURORA ENERGY LLC	3/4/2014	13	7678	26.91	9.19	35.01	28.89	0.23	Bdl/STK	B	4/N	1,195.00
AURORA ENERGY LLC	3/5/2014	11	7784	26.75	8.53	35.75	28.96	0.21	Bdl/STK	B	4/N	1,084.80
AURORA ENERGY LLC	3/6/2014	7	7723	26.83	8.71	35.41	29.05	0.18	Bdl/STK	B	4/N	691.95
AURORA ENERGY LLC	3/7/2014	7	7758	26.72	8.49	35.58	29.20	0.19	Bdl/STK	B	4/N	666.20
AURORA ENERGY LLC	3/10/2014	7	7719	26.52	9.09	35.53	28.86	0.22	Bdl/STK	B	4/N	671.50
AURORA ENERGY LLC	3/11/2014	11	7675	27.64	8.15	35.24	28.97	0.20	Bdl/STK	B	4/N	1,016.05
AURORA ENERGY LLC	3/12/2014	4	7634	27.35	8.82	35.17	28.66	0.21	Bdl/STK	B	4/N	394.50
AURORA ENERGY LLC	3/13/2014	16	7120	26.15	14.55	33.06	26.25	0.25	Bdl/STK	B	4/N	1,555.45
AURORA ENERGY LLC	3/14/2014	12	7615	27.55	9.03	34.97	28.45	0.18	Bdl/STK	B	4/N	1,178.10
AURORA ENERGY LLC	3/17/2014	3	7872	26.97	7.37	36.05	29.62	0.18	Bdl	B	4	281.15
AURORA ENERGY LLC	3/18/2014	12	7750	27.82	7.64	34.83	29.70	0.16	Bdl/STK	B	4/N	1,093.55
AURORA ENERGY LLC	3/19/2014	12	7798	27.45	7.40	35.78	29.38	0.18	Bdl/STK	B	4/N	1,128.70
AURORA ENERGY LLC	3/20/2014	10	7948	26.46	7.32	36.57	29.84	0.23	Bdl/STK	B	4/N	951.45
AURORA ENERGY LLC	3/21/2014	12	7916	27.92	6.00	35.87	30.22	0.12	Bdl	B	4	1,075.20
AURORA ENERGY LLC	3/24/2014	12	7882	27.38	6.81	35.69	15.13	0.14	Bdl/STK	B	4/N	1,043.95
AURORA ENERGY LLC	3/25/2014	1	8057	26.46	6.27	36.20	31.04	0.13	Bdl/STK	B	4/N	85.90
AURORA ENERGY LLC	3/26/2014	15	7887	27.68	6.78	35.65	29.90	0.12	Bdl/T II	B/X3	4/3	1,414.80
AURORA ENERGY LLC	3/27/2014	26	7482	27.96	9.07	34.76	28.21	0.11	TII	X3	3	2,390.75
AURORA ENERGY LLC	3/31/2014	8	7310	27.68	11.54	33.38	27.41	0.13	T II	X3	3	783.60
AURORA ENERGY LLC	4/1/2014	9	7832	28.80	5.23	35.61	30.37	0.10	Bdl	A	3	825.10
AURORA ENERGY LLC	4/2/2014	13	7776	28.29	5.87	35.47	30.37	0.11	Bdl/STK	A	3/N	1,226.70
AURORA ENERGY LLC	4/3/2014	9	7549	27.52	8.97	34.22	29.30	0.13	Bdl/STK	A	3/N	892.80

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Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	4/4/2014	5	7695	28.07	7.91	34.98	29.05	0.11	T II/Bdl	X3/A	3/3	486.30
AURORA ENERGY LLC	4/7/2014	10	7899	28.09	5.97	35.24	30.71	0.12	Bdl	A	3	913.65
AURORA ENERGY LLC	4/8/2014	10	7861	28.29	6.32	34.97	30.43	0.12	Bdl/STK	A	3/N	951.00
AURORA ENERGY LLC	4/9/2014	14	7878	27.84	6.59	35.28	30.30	0.12	Bdl/STK	A	3/N	1,358.65
AURORA ENERGY LLC	4/10/2014	13	7734	28.36	7.47	34.44	29.73	0.12	Bdl/STK	A	3/N	1,286.85
AURORA ENERGY LLC	4/11/2014	9	7609	28.55	8.22	34.50	28.74	0.12	Bdl/STK	A	3/N	866.30
AURORA ENERGY LLC	4/14/2014	10	7769	27.99	7.38	34.83	29.80	0.11	Bdl/STK	A	3/N	938.10
AURORA ENERGY LLC	4/15/2014	12	7662	28.55	7.20	36.80	27.46	0.13	T II	LST	6	1,108.05
AURORA ENERGY LLC	4/16/2014	11	7262	27.55	11.33	35.30	25.83	0.13	T II	LST	6	950.55
AURORA ENERGY LLC	4/17/2014	13	7462	28.02	9.11	36.75	26.14	0.10	TII	LST	6	1,131.00
AURORA ENERGY LLC	4/18/2014	13	7632	29.53	4.91	36.14	29.42	0.07	Bdl/STK	A	3/N	1,247.60
AURORA ENERGY LLC	4/21/2014	9	7627	27.72	7.25	35.32	29.71	0.11	Bdl/STK	B	3/N	832.25
AURORA ENERGY LLC	4/22/2014	11	7451	27.99	9.12	35.47	27.43	0.13	T II	LST	6	1,070.80
AURORA ENERGY LLC	4/23/2014	11	7525	28.07	8.16	35.70	28.07	0.12	Bdl/STK	B	3/N	999.30
AURORA ENERGY LLC	4/24/2014	12	7570	28.32	8.11	36.21	27.36	0.12	T II	LST	6	1,162.05
AURORA ENERGY LLC	4/25/2014	13	7464	28.40	8.61	36.49	26.51	0.13	TII	LST	6	1,204.30
AURORA ENERGY LLC	4/28/2014	11	7451	27.57	9.55	35.68	27.20	0.13	T II	LST	6	1,083.20
AURORA ENERGY LLC	4/30/2014	12	7397	27.69	9.76	36.58	25.97	0.12	TII	LST	6	1,093.95
AURORA ENERGY LLC	5/1/2014	12	7464	27.86	9.03	36.29	26.82	0.13	TII	LST	6	1,094.60
AURORA ENERGY LLC	5/5/2014	11	7601	28.24	8.15	36.22	27.39	0.14	T II	LST	6	994.65
AURORA ENERGY LLC	5/6/2014	10	7735	27.79	7.63	36.55	28.04	0.14	T II	LST	6	906.90
AURORA ENERGY LLC	5/7/2014	12	7638	28.23	7.46	36.83	27.49	0.13	T II	LST	6	1,121.35
AURORA ENERGY LLC	5/8/2014	14	7544	28.57	8.21	35.22	28.00	0.13	T II/Bsl	LST/A	6/3	1,403.70
AURORA ENERGY LLC	5/12/2014	16	7796	27.50	8.05	35.31	29.14	0.13	Bdl/STK	A	3/N	1,548.15
AURORA ENERGY LLC	5/14/2014	12	7746	28.25	6.78	37.35	27.62	0.12	Bdl/TII	A/LST	3/6	1,055.15
AURORA ENERGY LLC	5/15/2014	9	7712	28.25	7.12	37.35	27.28	0.12	Bdl/TII	A/LST	3/6	858.05
AURORA ENERGY LLC	5/16/2014	10	7707	27.99	7.76	36.08	28.18	0.11	TII/Bdl	LST/A	6/3	974.80
AURORA ENERGY LLC	5/19/2014	8	7769	26.93	7.92	35.48	29.68	0.13	TII/Bdl	LST/B	6/3	769.15
AURORA ENERGY LLC	5/20/2014	11	7915	28.22	6.07	35.62	30.10	0.11	Bdl/STK	B	3/N	1,041.70
AURORA ENERGY LLC	5/21/2014	9	7761	27.26	8.12	35.07	29.56	0.12	Bdl/STK	B	3/N	891.85
AURORA ENERGY LLC	5/22/2014	7	7809	27.38	7.27	35.93	29.43	0.11	Bdl/STK	B	3/N	693.85
AURORA ENERGY LLC	5/23/2014	8	7726	28.33	6.92	38.24	26.52	0.12	TII	LST	6	724.90

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/14 to 6/30/14

AURORA ENERGY LLC	5/26/2014	7	7723	28.31	6.78	38.02	26.90	0.12	TII	LST	6	614.05
AURORA ENERGY LLC	5/28/2014	14	7654	26.98	8.94	35.73	28.36	0.12	Bdl/STK	B	3/N	1,342.05
AURORA ENERGY LLC	5/29/2014	12	7514	27.86	9.02	34.63	28.50	0.13	Bdl/STK	B	3/N	1,174.15
AURORA ENERGY LLC	5/30/2014	12	7673	27.44	8.50	34.98	29.08	0.11	Bdl/STK	B	3/N	1,150.20
AURORA ENERGY LLC	6/2/2014	8	7688	27.53	8.31	34.79	29.39	0.11	Bdl/STK	B	3/N	793.70
AURORA ENERGY LLC	6/3/2014	8	7949	27.23	6.72	36.14	29.91	0.11	Bdl/STK	B	3/N	779.60
AURORA ENERGY LLC	6/5/2014	13	7690	28.12	7.45	36.87	27.56	0.13	T II	LST	6	1,236.80
AURORA ENERGY LLC	6/9/2014	5	7676	28.30	7.60	36.90	27.20	0.12	T II	LST	6	481.65
AURORA ENERGY LLC	6/11/2014	7	7704	26.60	10.00	35.94	27.47	0.14	T II/GRP	LST	6/M	683.90
AURORA ENERGY LLC	6/12/2014	5	7669	27.41	8.70	37.27	26.62	0.11	GRP/TII	LST	M/6	489.40
AURORA ENERGY LLC	6/16/2014	10	7632	27.40	8.88	36.76	26.96	0.12	T II	LST	6	964.10
AURORA ENERGY LLC	6/18/2014	16	7672	27.62	7.90	37.02	27.47	0.12	T II	LST	6	1,534.80
AURORA ENERGY LLC	6/19/2014	18	7458	27.53	9.65	36.66	26.16	0.11	TII	LST	6	1,681.40
AURORA ENERGY LLC	6/23/2014	9	7311	28.02	10.34	35.77	25.87	0.15	T II	LST	6	867.60
AURORA ENERGY LLC	6/24/2014	10	7712	27.76	8.03	34.70	29.51	0.12	Bdl/STK	C	3/N	931.05
AURORA ENERGY LLC	6/25/2014	13	7751	28.21	7.20	34.95	29.64	0.11	Bdl/STK	C	3/N	1,259.45
AURORA ENERGY LLC	6/26/2014	12	7776	27.04	7.86	35.66	29.45	0.11	Bdl/STK	C	3/N	1,172.35
AURORA ENERGY LLC	6/30/2014	9	7695	28.75	7.46	34.73	29.06	0.11	Bdl/STK	C	3/N	829.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	117659.65	7652.00	27.89	8.15	35.29	28.54	0.15

This analysis is representative of the coal shipped using
sulfur standard ASTM D4239 - 12

Coleen Thompson
7-2-14

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/1/2014	17	7525	28.93	8.28	34.19	28.60	0.12	Bdl/STK	C	3/N	1,638.75
AURORA ENERGY LLC	7/2/2014	11	7442	29.33	8.64	34.80	27.23	0.13	Bdl/STK	C	3/N	1,079.80
AURORA ENERGY LLC	7/4/2014	7	7656	27.98	8.07	36.98	26.97	0.11	TII	LST	6	627.85
AURORA ENERGY LLC	7/7/2014	13	7622	28.13	7.79	37.11	26.97	0.12	T II	LST	6	1,239.90
AURORA ENERGY LLC	7/9/2014	33	7578	28.14	8.43	36.77	26.67	0.13	T II	LST	6	3,141.00
AURORA ENERGY LLC	7/14/2014	13	7395	27.68	9.60	36.03	26.72	0.13	T II	LST	6	1,276.45
AURORA ENERGY LLC	7/16/2014	18	7619	28.26	7.73	36.94	27.08	0.12	T II	LST	6	1,699.05
AURORA ENERGY LLC	7/17/2014	18	7570	28.11	8.29	36.76	26.84	0.12	T II	LST	6	1,778.65
AURORA ENERGY LLC	7/21/2014	14	7442	28.16	9.30	36.11	26.43	0.13	T II	LST	6	1,346.20
AURORA ENERGY LLC	7/23/2014	16	7409	28.35	9.31	36.18	26.16	0.12	T II	LST	6	1,446.00
AURORA ENERGY LLC	7/24/2014	17	7621	27.21	8.61	37.30	26.88	0.11	TII	LST	6	1,544.95
AURORA ENERGY LLC	7/28/2014	5	7539	27.66	8.85	36.81	26.69	0.12	T II	LST	6	490.95
AURORA ENERGY LLC	7/30/2014	6	7675	26.58	9.28	36.70	27.45	0.14	Bdl	C1	6	569.15
AURORA ENERGY LLC	8/4/2014	8	7404	29.01	8.95	35.65	26.39	0.13	T II	LST	6	795.30
AURORA ENERGY LLC	8/5/2014	8	7750	27.08	8.18	37.34	27.40	0.13	TBR	C1	6	703.80
AURORA ENERGY LLC	8/6/2014	17	7586	26.84	9.66	36.79	26.71	0.14	TBR	C1	6	1,686.45
AURORA ENERGY LLC	8/7/2014	13	7425	27.57	10.25	36.28	25.91	0.13	TBR	C1	6	1,299.70
AURORA ENERGY LLC	8/11/2014	8	7702	27.08	8.56	36.95	27.42	0.13	TBR	C1	6	781.45
AURORA ENERGY LLC	8/13/2014	18	7601	26.69	9.52	36.64	27.16	0.13	TBR	C1	6	1,605.50
AURORA ENERGY LLC	8/14/2014	16	7510	26.42	10.35	36.71	26.53	0.12	TBR	C1	6	1,500.05
AURORA ENERGY LLC	8/16/2014	10	7952	25.09	10.53	36.52	27.87	0.19	GRP/STK		M/N	937.00
AURORA ENERGY LLC	8/18/2014	4	7846	25.81	10.48	35.39	28.33	0.17	GRP/STK		M/N	403.90
AURORA ENERGY LLC	8/20/2014	5	7972	25.66	10.21	34.89	29.25	0.16	GRP/STK		M/N	479.00
AURORA ENERGY LLC	8/21/2014	5	7947	25.16	10.86	35.53	28.45	0.16	GRP/STK		M/N	472.20
AURORA ENERGY LLC	8/25/2014	6	7585	26.17	11.19	35.79	26.86	0.14	GRP/STK		M/N	575.15
AURORA ENERGY LLC	8/27/2014	5	7844	26.46	9.73	35.49	28.33	0.15	GRP/STK		M/N	459.95
AURORA ENERGY LLC	8/28/2014	5	7573	27.55	9.51	35.82	27.13	0.13	TBR	C1	6	453.20
AURORA ENERGY LLC	9/2/2014	5	7853	25.68	10.15	35.75	28.43	0.16	GRP/STK		M/N	444.10
AURORA ENERGY LLC	9/3/2014	7	7595	27.30	9.44	35.06	28.21	0.23	Bdl	E	4	599.15
AURORA ENERGY LLC	9/5/2014	9	7114	24.06	18.79	32.49	24.76	0.24	GRP/STK		M/N	804.25

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	9/5/2014	3	7828	23.73	14.19	34.29	27.79	0.22	GRP/STK		M/N	268.65
AURORA ENERGY LLC	9/5/2014	6	7651	23.59	15.37	33.86	27.19	0.23	GRP/STK		M/N	539.60
AURORA ENERGY LLC	9/8/2014	6	7455	27.39	10.16	36.70	25.75	0.13	Bdl	E	4	535.55
AURORA ENERGY LLC	9/10/2014	12	7336	28.02	10.03	35.87	26.09	0.13	T II	LST	6	1,100.05
AURORA ENERGY LLC	9/11/2014	10	7155	27.65	12.33	34.95	25.08	0.13	T II	LST	6	941.35
AURORA ENERGY LLC	9/15/2014	5	7517	27.42	9.62	35.72	27.25	0.17	Bdl	E	4	464.40
AURORA ENERGY LLC	9/17/2014	7	7531	27.52	9.06	36.59	26.84	0.13	T II	LST	6	652.45
AURORA ENERGY LLC	9/18/2014	6	7493	27.99	8.91	35.72	27.39	0.19	T II	LST	6	539.45
AURORA ENERGY LLC	9/22/2014	5	7793	28.38	6.50	35.62	29.51	0.14	Bdl	E	4	481.40
AURORA ENERGY LLC	9/24/2014	9	7206	26.90	12.00	35.04	26.07	0.13	T II	LST	6	864.35
AURORA ENERGY LLC	9/25/2014	10	7528	28.00	8.47	36.92	26.61	0.12	TII	LST	6	971.75
AURORA ENERGY LLC	9/27/2014	11	7739	28.34	6.81	36.34	28.51	0.18	Bdl	E	4	1,007.10
AURORA ENERGY LLC	9/29/2014	11	7739	28.09	6.87	35.86	29.18	0.19	Bdl	F	4	1,034.60
AURORA ENERGY LLC	9/30/2014	11	7749	28.54	6.60	35.47	29.41	0.16	Bdl	F	4	984.35
AURORA ENERGY LLC	10/1/2014	26	7815	28.29	6.55	35.84	29.32	0.16	Bdl	F	4	2,485.80
AURORA ENERGY LLC	10/6/2014	10	7591	28.11	8.20	36.05	27.65	0.16	Bdl/TII	F/LST	4/6	856.70
AURORA ENERGY LLC	10/8/2014	9	7403	27.49	10.14	35.31	27.07	0.16	Bdl/T II	F/LST	4/6	810.80
AURORA ENERGY LLC	10/8/2014	11	7499	28.23	8.70	36.11	26.96	0.12	T II	LST	6	985.90
AURORA ENERGY LLC	10/9/2014	12	7495	28.17	8.40	36.91	26.52	0.12	T II	LST	6	1,116.25
AURORA ENERGY LLC	10/11/2014	13	7566	28.43	7.85	38.08	25.65	0.12	T II	LST	6	1,133.10
AURORA ENERGY LLC	10/13/2014	7	7405	27.91	9.44	36.23	26.43	0.13	T II	LST	6	676.50
AURORA ENERGY LLC	10/15/2014	11	7971	26.15	9.33	35.38	29.13	0.15	GRP/STK		M/N	997.30
AURORA ENERGY LLC	10/16/2014	16	8040	25.93	8.50	36.45	29.13	0.16	GRP/STK		M/N	1,476.75
AURORA ENERGY LLC	10/20/2014	9	7629	27.68	8.84	36.03	27.45	0.14	T II	LST	6	864.20
AURORA ENERGY LLC	10/21/2014	12	7874	27.45	7.56	35.30	29.69	0.13	Bdl	D	3	1,113.15
AURORA ENERGY LLC	10/22/2014	15	7932	27.59	6.48	35.31	30.62	0.12	Bdl	E	3	1,424.60
AURORA ENERGY LLC	10/23/2014	14	7880	27.56	6.24	36.02	30.19	0.10	Bdl	E	3	1,343.80
AURORA ENERGY LLC	10/24/2014	9	7169	30.71	6.85	34.67	27.79	0.12	Jumbo			783.45
AURORA ENERGY LLC	10/27/2014	12	7748	28.04	7.14	35.35	29.47	0.13	Bdl/STK	D	3/N	1,187.15
AURORA ENERGY LLC	10/28/2014	10	7616	28.45	7.79	35.64	28.13	0.12	Bdl/T II	D/LST	3/6	922.05
AURORA ENERGY LLC	10/29/2014	10	7494	28.14	8.94	35.97	26.95	0.13	T II	LST	6	939.80
AURORA ENERGY LLC	10/30/2014	11	[illegible]	[illegible]	[illegible]	[illegible]	26.15	0.12	TII	LST	6	1,074.40

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	10/31/2014	10	7754	28.43	7.39	36.13	28.06	0.13	TII/Bdl	LST/D	6/3	943.50
AURORA ENERGY LLC	11/3/2014	6	7675	29.16	6.72	34.86	29.26	0.12	Bdl/JD	D	3/4	566.40
AURORA ENERGY LLC	11/4/2014	13	7741	28.44	6.73	35.24	29.59	0.11	Bdl/JD	D	3/4	1,279.15
AURORA ENERGY LLC	11/5/2014	12	7651	28.22	7.68	35.38	28.73	0.12	Bdl/JD	D	3/4	1,176.25
AURORA ENERGY LLC	11/6/2014	9	7622	28.67	7.42	34.84	29.07	0.12	Bdl/JD	D	3/4	848.35
AURORA ENERGY LLC	11/7/2014	12	7769	28.00	7.20	35.32	29.48	0.11	Bdl/JD	D	3/4	1,064.60
AURORA ENERGY LLC	11/10/2014	7	7769	28.21	6.77	35.31	29.71	0.10	Bdl/JD	D	3/4	650.70
AURORA ENERGY LLC	11/11/2014	12	7739	28.65	6.64	35.20	29.52	0.11	Bdl/JD	D	3/4	1,141.50
AURORA ENERGY LLC	11/12/2014	12	7644	29.46	6.67	34.68	29.19	0.12	Bdl/JD	D	3/4	1,120.25
AURORA ENERGY LLC	11/13/2014	9	7613	29.14	6.79	35.81	28.27	0.11	Bdl/JD	D	3/4	840.50
AURORA ENERGY LLC	11/14/2014	7	7805	27.58	7.75	36.16	28.52	0.14	Bdl/JD	D	3/4	638.10
AURORA ENERGY LLC	11/17/2014	6	7749	26.36	10.84	34.65	28.16	0.19	GRP/STK		M/N	604.55
AURORA ENERGY LLC	11/18/2014	31	7295	26.35	14.74	33.00	25.91	0.17	GRP/STK		M/N	3,113.25
AURORA ENERGY LLC	11/19/2014	12	7822	25.92	11.05	34.90	28.14	0.17	GRP/Bdl	D	M/3	1,161.75
AURORA ENERGY LLC	11/21/2014	4	7765	27.96	9.54	34.70	27.80	0.14	GRP/JD		M/4	355.30
AURORA ENERGY LLC	11/24/2014	9	7821	29.00	5.59	36.00	29.41	0.11	Bdl/JD	F	3/4	792.50
AURORA ENERGY LLC	11/25/2014	12	7837	28.38	5.94	35.63	30.05	0.10	Bdl/JD	F	3/4	1,101.60
AURORA ENERGY LLC	11/26/2014	13	7636	29.62	6.57	35.03	28.79	0.09	Bdl/JD	D	3/4	1,157.55
AURORA ENERGY LLC	11/28/2014	9	7798	28.82	6.04	35.55	29.58	0.09	Bdl/JD	F	3/4	775.45
AURORA ENERGY LLC	12/1/2014	8	7814	28.53	6.40	35.39	29.68	0.10	Bdl/STK	F	3/N	742.55
AURORA ENERGY LLC	12/2/2014	11	7843	27.99	6.73	35.16	30.13	0.11	Bdl/STK	F	3/N	1,039.75
AURORA ENERGY LLC	12/3/2014	10	7718	28.26	7.17	35.07	29.51	0.10	Bdl/STK	F	3/N	862.65
AURORA ENERGY LLC	12/4/2014	8	7659	27.93	7.94	35.42	28.71	0.10	Bdl/STK	F	3/N	753.20
AURORA ENERGY LLC	12/5/2014	13	7660	27.86	8.23	35.41	28.51	0.12	Bdl/STK	F	3/N	1,222.65
AURORA ENERGY LLC	12/8/2014	11	7399	26.38	12.62	34.16	26.85	0.31	Bdl/STK	G	4/N	1,068.05
AURORA ENERGY LLC	12/9/2014	10	7758	27.16	8.46	35.76	28.61	0.25	Bdl/STK	G	4/N	933.35
AURORA ENERGY LLC	12/10/2014	8	7671	27.12	8.79	35.30	28.79	0.23	Bdl/STK	G	4/N	730.55
AURORA ENERGY LLC	12/11/2014	9	7762	27.40	8.01	35.48	29.12	0.21	Bdl/Bdl	G/F	4/3	846.70
AURORA ENERGY LLC	12/12/2014	14	7657	27.61	8.26	35.28	28.85	0.15	Bdl/STK	F	3/N	1,285.70
AURORA ENERGY LLC	12/15/2014	12	7491	29.18	8.10	35.28	27.44	0.15	Bdl/JD	G	4/4	1,100.15
AURORA ENERGY LLC	12/16/2014	18	7630	28.23	8.32	35.71	27.74	0.19	Bdl/JD	G	4/4	1,705.05
AURORA ENERGY LLC	12/17/2014	8	7644	28.82	7.58	35.21	28.40	0.16	Bdl/JD	G	4/4	770.15

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/14 to 12/31/14

AURORA ENERGY LLC	12/18/2014	20	7528	31.48	6.44	34.37	27.71	0.13	JD		4	1,850.00
AURORA ENERGY LLC	12/19/2014	4	7626	28.89	7.57	35.42	28.12	0.15	Bdl/JD	G	4/4	372.05
AURORA ENERGY LLC	12/22/2014	10	7561	28.72	8.34	35.26	27.69	0.18	Bdl/JD	G	4/4	981.45
AURORA ENERGY LLC	12/23/2014	17	7598	28.65	8.05	35.35	27.95	0.18	Bdl/JD	G	4/4	1,535.65
AURORA ENERGY LLC	12/24/2014	12	7563	28.54	8.75	35.22	27.50	0.19	Bdl/JD	G	4/4	1,037.65
AURORA ENERGY LLC	12/26/2014	6	7418	26.62	12.03	34.98	26.37	0.28	Bdl/JD	G	4/4	550.45
AURORA ENERGY LLC	12/29/2014	8	7385	27.89	10.46	34.77	26.89	0.25	Bdl/JD	G	4/4	778.85
AURORA ENERGY LLC	12/30/2014	12	7568	29.02	8.07	34.65	28.26	0.21	Bdl/JD	G	4/4	1,145.15
AURORA ENERGY LLC	12/31/2014	10	7643	29.27	7.21	35.29	28.24	0.18	Bdl/JD	G	4/4	880.85

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103979.45	7617.00	27.86	8.67	35.66	27.82	0.14

This analysis is representative of the coal shipped using sulfur ASTM D4239-12

Colleen Thompson
1-5-15

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/15 to 6/30/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/2/2015	10	7542	28.10	8.78	35.14	27.98	0.22	Bdl/JD	G	4/4	913.35
AURORA ENERGY LLC	1/5/2015	8	7586	29.30	7.87	34.51	28.33	0.21	Bdl/JD	G	4/4	761.95
AURORA ENERGY LLC	1/6/2015	15	7593	29.68	7.16	34.84	28.32	0.21	Bdl/JD	G	4/4	1,331.30
AURORA ENERGY LLC	1/7/2015	10	7609	29.88	6.82	34.57	28.74	0.19	Bdl/JD	G	4/4	913.10
AURORA ENERGY LLC	1/8/2015	13	7572	27.19	9.58	35.09	28.15	0.24	Bdl/JD	G	4/4	1,217.90
AURORA ENERGY LLC	1/9/2015	13	7658	28.66	7.66	35.64	28.04	0.20	Bdl/JD	G	4/4	1,270.65
AURORA ENERGY LLC	1/12/2015	8	7612	27.19	9.36	35.22	28.24	0.22	Bdl/ T II	G/LST	4/6	735.75
AURORA ENERGY LLC	1/13/2015	13	7605	27.86	8.81	35.00	28.33	0.21	Bdl/T II	G/LST	4/6	1,249.40
AURORA ENERGY LLC	1/14/2015	30	7355	26.04	12.63	34.27	27.07	0.31	Bdl/STK	G	4/N	2,906.30
AURORA ENERGY LLC	1/14/2015	10	7413	26.77	11.28	34.53	27.42	0.30	Bdl/STK	G	4/N	985.30
AURORA ENERGY LLC	1/19/2015	8	7722	27.69	7.86	35.65	28.80	0.15	Bdl/STK	G	4/N	710.60
AURORA ENERGY LLC	1/20/2015	13	7615	28.20	7.93	36.17	27.71	0.15	TII/STK	LST	6/N	1,225.25
AURORA ENERGY LLC	1/21/2015	10	7493	27.67	9.57	36.02	26.75	0.14	T II	LST	6	954.30
AURORA ENERGY LLC	1/22/2015	8	7625	27.33	8.98	35.40	28.28	0.22	Bdl/STK	G	4/N	778.30
AURORA ENERGY LLC	1/26/2015	9	7635	27.97	7.73	35.95	28.36	0.15	Bdl/T II	F/LST	3/6	835.50
AURORA ENERGY LLC	1/27/2015	7	7516	28.18	8.81	36.32	26.69	0.14	T II	LST	6	645.20
AURORA ENERGY LLC	1/28/2015	5	7469	28.31	9.15	36.13	26.41	0.15	T II	LST	6	448.45
AURORA ENERGY LLC	1/29/2015	6	7515	28.38	8.44	36.63	26.56	0.13	TII	LST	6	554.05
AURORA ENERGY LLC	1/29/2015	5	7607	28.03	8.04	36.88	27.05	0.13	TII	LST	6	424.60
AURORA ENERGY LLC	1/30/2015	14	7541	28.33	8.44	37.02	26.22	0.13	TII	LST	6	1,209.20
AURORA ENERGY LLC	2/2/2015	9	7551	28.26	8.55	36.52	26.67	0.14	TII	LST	6	834.90
AURORA ENERGY LLC	2/3/2015	31	7078	28.44	12.14	34.70	24.73	0.15	T II	LST	6	2,869.90
AURORA ENERGY LLC	2/3/2015	11	7036	27.65	12.98	35.06	24.32	0.14	T II	LST	6	969.85
AURORA ENERGY LLC	2/4/2015	12	7065	28.03	12.16	34.62	25.20	0.15	T II	LST	6	1,138.45
AURORA ENERGY LLC	2/9/2015	9	7620	27.91	7.79	35.30	29.02	0.13	Bdl/JD	F	3/4	742.75
AURORA ENERGY LLC	2/10/2015	14	7917	27.82	5.80	35.90	30.48	0.12	Bdl/JD	F	3/4	1,277.15
AURORA ENERGY LLC	2/11/2015	8	7702	29.02	6.64	35.33	29.02	0.12	Bdl/JD	F	3/4	680.85
AURORA ENERGY LLC	2/12/2015	6	7618	28.59	7.59	35.98	27.84	0.12	Bdl/JD	F	3/4	525.70
AURORA ENERGY LLC	2/13/2015	8	7614	29.50	7.11	35.67	27.72	0.12	Bdl/JD	F	3/4	674.15
AURORA ENERGY LLC	2/16/2015	8	7681	29.80	6.49	35.97	27.74	0.11	T II/JD	LST	6/4	716.15

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Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	2/17/2015	10	7645	30.40	6.24	35.65	27.71	0.12	JD		4	871.10
AURORA ENERGY LLC	2/18/2015	9	7411	30.93	6.97	34.84	27.27	0.13	T II/JD	LST	6/4	775.50
AURORA ENERGY LLC	2/19/2015	10	7474	29.85	7.43	36.13	26.59	0.12	JD/T II	LST	4/6	893.10
AURORA ENERGY LLC	2/20/2015	12	7556	30.19	6.65	36.82	26.35	0.12	T II/JD	LST	6/4	1,087.75
AURORA ENERGY LLC	2/23/2015	8	7490	30.65	6.82	35.48	27.06	0.13	T II/JD	LST	6/4	756.30
AURORA ENERGY LLC	2/24/2015	11	7576	29.59	7.24	35.95	27.22	0.14	JD/TII	LST	4/6	975.50
AURORA ENERGY LLC	2/25/2015	11	7551	29.41	7.42	35.92	27.25	0.13	T II/JD	LST	6/4	1,033.85
AURORA ENERGY LLC	2/26/2015	11	7582	29.74	6.75	36.28	27.23	0.12	T II/JD	LST	6/4	1,003.80
AURORA ENERGY LLC	2/27/2015	11	7588	29.97	6.61	36.05	27.37	0.12	TII/JD	LST	6/4	1,039.00
AURORA ENERGY LLC	3/2/2015	8	7571	29.92	6.43	36.02	27.64	0.12	TII/JD	LST	6/4	730.55
AURORA ENERGY LLC	3/3/2015	10	7698	29.84	5.91	36.58	27.67	0.11	TII/JD	LST	6/4	910.05
AURORA ENERGY LLC	3/4/2015	4	7547	30.62	6.34	35.70	27.34	0.11	TII/JD	LST	6/4	356.15
AURORA ENERGY LLC	3/5/2015	10	7705	29.51	6.01	36.35	28.13	0.11	TII/JD	LST	6/4	927.65
AURORA ENERGY LLC	3/6/2015	11	7662	30.66	5.49	36.26	27.60	0.11	TII/JD	LST	6/4	1,032.00
AURORA ENERGY LLC	3/10/2015	6	7505	30.34	6.76	36.30	26.60	0.11	TII/JD	LST	6/4	549.70
AURORA ENERGY LLC	3/11/2015	26	7109	31.44	7.90	34.89	25.76	0.10	TII/JD	LST	6/4	2,416.95
AURORA ENERGY LLC	3/12/2015	7	7483	29.94	7.34	35.71	27.02	0.11	TII/JD	LST	6/4	620.10
AURORA ENERGY LLC	3/16/2015	4	7525	29.76	7.33	35.86	27.05	0.14	TII/JD	LST	6/4	370.10
AURORA ENERGY LLC	3/17/2015	5	7468	30.08	7.36	35.59	26.98	0.11	TII/JD	LST	6/4	463.30
AURORA ENERGY LLC	3/18/2015	12	7545	30.21	6.84	35.43	27.53	0.12	TII/JD	LST	6/4	1,088.95
AURORA ENERGY LLC	3/19/2015	12	7549	29.60	7.58	35.96	26.86	0.14	TII/JD	LST	6/4	1,105.10
AURORA ENERGY LLC	3/20/2015	7	7620	29.93	7.00	36.02	27.06	0.12	TII/JD	LST	6/4	680.20
AURORA ENERGY LLC	3/23/2015	5	7555	29.89	6.88	35.98	27.26	0.12	TII/JD	LST	6/4	453.55
AURORA ENERGY LLC	4/2/2015	7	7727	30.71	5.38	35.08	28.84	0.12	JD		4	641.55
AURORA ENERGY LLC	4/6/2015	10	7763	31.03	4.67	35.18	29.13	0.11	JD		4	908.40
AURORA ENERGY LLC	4/7/2015	12	7826	30.95	4.55	35.57	28.93	0.11	JD		4	1,081.35
AURORA ENERGY LLC	4/8/2015	11	7669	31.37	5.35	34.58	28.71	0.11	JD		4	1,022.50
AURORA ENERGY LLC	4/9/2015	13	7561	31.87	5.36	34.64	28.14	0.12	JD		4	1,161.20
AURORA ENERGY LLC	4/10/2015	7	7759	30.74	5.03	35.70	28.54	0.11	JD		4	660.95
AURORA ENERGY LLC	4/13/2015	9	7711	31.37	4.82	34.74	29.07	0.11	JD		4	798.25
AURORA ENERGY LLC	4/14/2015	12	7710	31.37	4.77	35.27	28.60	0.11	JD		4	1,105.30
AURORA ENERGY LLC	4/20/2015	9	7625	30.63	5.99	34.56	28.82	0.09	JD		4	836.95

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Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	4/21/2015	11	7544	30.03	7.59	33.80	28.58	0.11	JD		4	989.35
AURORA ENERGY LLC	4/22/2015	8	7626	29.64	7.23	34.32	28.81	0.14	Bdl/JD	G	4/4	768.10
AURORA ENERGY LLC	4/27/2015	8	7881	29.30	5.28	35.34	30.09	0.11	JD/Bdl	G	4/3	745.75
AURORA ENERGY LLC	4/28/2015	10	7853	29.01	5.21	35.72	30.06	0.11	Bdl/JD	G	3/4	903.75
AURORA ENERGY LLC	4/29/2015	10	7620	31.74	4.50	35.15	28.61	0.10	JD		4	904.95
AURORA ENERGY LLC	4/30/2015	12	7648	28.84	7.36	34.53	29.28	0.11	Bdl/JD	G	3/4	1,151.95
AURORA ENERGY LLC	5/1/2015	8	7453	31.00	6.78	34.50	27.73	0.10	JD		4	733.95
AURORA ENERGY LLC	5/4/2015	10	7424	31.57	6.35	34.12	27.97	0.12	JD		4	891.35
AURORA ENERGY LLC	5/5/2015	8	7414	31.82	6.59	33.68	27.91	0.11	JD		4	747.95
AURORA ENERGY LLC	5/6/2015	11	7610	30.24	6.28	34.87	28.62	0.11	Bdl/JD	G	3/4	980.55
AURORA ENERGY LLC	5/7/2015	9	7511	31.23	6.16	34.56	28.05	0.11	JD		4	873.00
AURORA ENERGY LLC	5/8/2015	8	7743	29.92	5.94	35.21	28.94	0.12	JD		4	704.65
AURORA ENERGY LLC	5/12/2015	15	7685	29.76	6.46	35.56	28.22	0.11	JD		4	1,411.50
AURORA ENERGY LLC	5/13/2015	15	7530	29.73	7.50	35.02	27.76	0.12	Bdl/JD	G	3/4	1,361.45
AURORA ENERGY LLC	5/14/2015	1	7565	30.33	6.72	34.88	28.08	0.11	JD		4	99.55
AURORA ENERGY LLC	5/18/2015	13	7707	29.87	6.38	35.17	28.58	0.11	JD		4	1,253.45
AURORA ENERGY LLC	5/19/2015	8	7694	30.15	6.19	34.79	28.88	0.11	JD		4	704.35
AURORA ENERGY LLC	5/20/2015	12	7626	30.39	6.33	34.90	28.38	0.12	JD		4	1,155.60
AURORA ENERGY LLC	5/21/2015	12	7494	31.30	6.38	34.44	27.89	0.11	JD		4	1,157.45
AURORA ENERGY LLC	5/23/2015	18	7765	29.51	6.18	35.46	28.85	0.11	JD		4	1,660.70
AURORA ENERGY LLC	5/26/2015	8	7580	29.83	7.16	34.99	28.03	0.12	JD		4	732.30
AURORA ENERGY LLC	5/27/2015	14	7685	28.61	7.56	35.32	28.52	0.12	JD		4	1,376.90
AURORA ENERGY LLC	5/28/2015	14	7626	29.63	6.99	34.90	28.48	0.12	JD		4	1,353.00
AURORA ENERGY LLC	5/29/2015	6	7579	30.41	6.82	34.66	28.11	0.13	JD		4	565.25
AURORA ENERGY LLC	6/1/2015	9	7636	30.25	6.18	35.13	28.44	0.12	JD		4	857.75
AURORA ENERGY LLC	6/2/2015	8	7728	31.26	4.72	35.04	28.98	0.12	JD		4	727.00
AURORA ENERGY LLC	6/3/2015	12	7547	31.16	6.51	33.90	28.44	0.12	JD		4	1,199.65
AURORA ENERGY LLC	6/4/2015	13	7792	30.16	5.50	34.95	29.39	0.12	JD		4	1,262.20
AURORA ENERGY LLC	6/5/2015	13	7703	30.94	5.14	35.45	28.48	0.11	JD		4	1,158.10
AURORA ENERGY LLC	6/8/2015	10	7842	30.61	4.60	35.17	29.63	0.11	JD		4	944.15
AURORA ENERGY LLC	6/9/2015	8	7726	30.82	5.57	34.59	29.03	0.12	JD		4	772.90
AURORA ENERGY LLC	6/10/2015	9	7794	30.29	4.94	35.61	29.16	0.12	JD		4	865.10

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Rail Samples

Analysis Results for 1/1/15 to 6/30/15

AURORA ENERGY LLC	6/11/2015	2	7952	29.43	5.92	34.72	29.93	0.12	GRP/STK		M/N	194.00
AURORA ENERGY LLC	6/12/2015	11	7855	28.23	7.74	34.69	29.34	0.14	GRP/STK		M/N	1,098.10
AURORA ENERGY LLC	6/15/2015	10	7900	26.99	8.73	35.33	28.95	0.14	GRP/STK		M/N	996.05
AURORA ENERGY LLC	6/16/2015	6	7887	25.37	10.64	35.26	28.73	0.15	GRP/STK		M/N	588.95
AURORA ENERGY LLC	6/17/2015	29	7528	24.32	14.26	34.44	26.99	0.15	GRP/STK		M/N	2,832.55
AURORA ENERGY LLC	6/17/2015	9	7518	24.53	13.61	35.06	26.81	0.15	GRP/STK		M/N	868.65
AURORA ENERGY LLC	6/22/2015	10	7649	28.27	8.58	35.13	28.03	0.13	JD		4	976.50
AURORA ENERGY LLC	6/23/2015	12	7581	28.39	8.07	34.39	29.15	0.13	Bdl		3	1,185.10
AURORA ENERGY LLC	6/24/2015	9	7885	27.12	7.70	35.35	29.83	0.13	Bdl/STK		6/N	861.60
AURORA ENERGY LLC	6/25/2015	8	7813	27.83	6.96	35.60	29.62	0.11	Bdl/STK	I	3/N	748.55
AURORA ENERGY LLC	6/26/2015	10	8048	26.19	8.73	35.21	29.87	0.15	GRP/STK		M/N	959.85
AURORA ENERGY LLC	6/29/2015	14	8027	26.68	8.75	34.64	29.93	0.15	GRP/STK		M/N	1,393.95
AURORA ENERGY LLC	6/30/2015	14	7934	27.67	7.69	35.54	29.11	0.14	JD		4	1,330.30

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	103904.80	7599.00	29.16	7.65	35.23	27.96	0.14

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-1-15

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/2/2015	5	7689	29.31	7.19	35.30	28.21	0.13	Bdl/GRP	I	3/M	497.30
AURORA ENERGY LLC	7/6/2015	14	7636	28.59	7.92	35.01	28.49	0.15	Bld	I	4	1,372.10
AURORA ENERGY LLC	7/7/2015	14	7874	26.58	7.76	36.94	28.71	0.21	Bdl	I	4	1,382.00
AURORA ENERGY LLC	7/8/2015	3	7865	26.43	7.83	36.21	29.54	0.21	BLD	I	4	316.65
AURORA ENERGY LLC	7/9/2015	8	7770	26.23	8.84	36.65	28.29	0.23	Bdl	I	4	785.95
AURORA ENERGY LLC	7/10/2015	5	7921	25.95	8.00	36.75	29.31	0.19	Bdl	I	4	508.65
AURORA ENERGY LLC	7/13/2015	10	7931	25.76	7.97	36.81	29.47	0.18	Bdl	I	4	979.25
AURORA ENERGY LLC	7/14/2015	10	7750	26.64	8.53	36.28	28.56	0.21	Bdl	I	4	954.80
AURORA ENERGY LLC	7/15/2015	10	7867	26.76	7.54	36.58	29.13	0.21	Bdl	I	4	982.35
AURORA ENERGY LLC	7/16/2015	15	7868	26.59	7.56	36.90	28.95	0.21	Bdl	I	4	1,462.70
AURORA ENERGY LLC	7/17/2015	8	7832	26.21	7.83	37.22	28.75	0.22	Bdl	I	4	765.40
AURORA ENERGY LLC	7/20/2015	8	7860	27.03	7.13	36.27	29.58	0.19	Bdl	I	4	766.65
AURORA ENERGY LLC	7/21/2015	9	7694	27.61	7.96	35.51	28.93	0.20	Bdl/STK	I	4/N	908.35
AURORA ENERGY LLC	7/22/2015	9	7657	29.32	6.95	35.01	28.72	0.15	JD		4	877.65
AURORA ENERGY LLC	7/23/2015	9	7438	30.33	7.55	34.18	27.95	0.12	JD		4	859.90
AURORA ENERGY LLC	7/24/2015	8	7636	29.50	6.86	35.30	28.35	0.11	JD		4	772.45
AURORA ENERGY LLC	7/27/2015	9	7432	31.12	7.58	33.61	27.70	0.13	JD		4	899.50
AURORA ENERGY LLC	7/28/2015	11	7523	30.83	6.76	34.27	28.14	0.12	JD		4	1,073.20
AURORA ENERGY LLC	7/30/2015	7	7425	30.34	7.77	34.10	27.79	0.14	JD		4	693.90
AURORA ENERGY LLC	7/31/2015	8	7734	27.22	7.93	35.90	28.96	0.22	Bdl/Bdl	I/I	3/4	724.30
AURORA ENERGY LLC	8/3/2015	9	7654	28.48	7.69	35.42	28.41	0.16	JD		4	867.75
AURORA ENERGY LLC	8/4/2015	10	7670	29.51	6.73	35.20	28.57	0.14	JD		4	937.50
AURORA ENERGY LLC	8/5/2015	12	7566	30.37	6.67	35.07	27.90	0.13	JD		4	999.75
AURORA ENERGY LLC	8/6/2015	11	7279	30.35	9.11	34.22	26.33	0.14	JD		4	1,037.80
AURORA ENERGY LLC	8/7/2015	11	7368	30.17	8.21	34.20	27.42	0.15	Bdl/JD	I	4/4	1,056.30
AURORA ENERGY LLC	8/10/2015	18	7660	29.39	6.76	35.20	28.65	0.15	JD/Bdl	/I	4/4	1,653.75
AURORA ENERGY LLC	8/12/2015	15	7359	31.58	7.10	33.94	27.40	0.14	JD		4	1,416.85
AURORA ENERGY LLC	8/13/2015	18	7510	30.41	6.79	34.63	28.16	0.17	Bdl/JD	I	4/4	1,775.95
AURORA ENERGY LLC	8/14/2015	15	7733	27.83	7.35	36.00	28.82	0.14	Bdl	I	4	1,397.60
AURORA ENERGY LLC	8/17/2015	10	7663	29.07	7.20	35.01	28.73	0.13	JD		4	943.65

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	8/18/2015	13	7658	28.80	7.07	35.38	28.76	0.16	JD		4	1,265.45
AURORA ENERGY LLC	8/20/2015	15	7311	31.47	7.37	33.83	27.33	0.12	Bdl/JD	I/	3/4	1,386.75
AURORA ENERGY LLC	8/22/2015	18	7564	31.72	6.35	34.30	27.63	0.10	JD		4	1,546.75
AURORA ENERGY LLC	8/26/2015	15	7740	28.52	8.85	34.07	28.56	0.17	JD/GRP		4/M	1,471.40
AURORA ENERGY LLC	8/28/2015	3	7642	28.09	8.57	35.40	27.94	0.15	GPR/Bdl		M/6	261.50
AURORA ENERGY LLC	8/31/2015	8	7628	27.35	8.96	36.33	27.37	0.14	Bdl		6	720.95
AURORA ENERGY LLC	9/1/2015	17	7681	27.34	8.39	36.84	27.43	0.13	Bdl		6	1,651.15
AURORA ENERGY LLC	9/2/2015	19	7563	27.07	9.34	36.51	27.09	0.14	Bdl		6	1,898.00
AURORA ENERGY LLC	9/3/2015	27	7665	27.56	8.27	35.87	28.31	0.13	Bdl		6	2,698.95
AURORA ENERGY LLC	9/8/2015	17	7806	27.29	7.46	35.64	29.61	0.13	Bdl/STK	I/	3/N	1,594.85
AURORA ENERGY LLC	9/10/2015	20	7891	26.52	7.77	35.76	29.97	0.14	Bdl/GRP	I/	3/M	1,863.50
AURORA ENERGY LLC	9/11/2015	21	7710	26.65	9.21	35.53	28.61	0.14	Bdl/GRP	I	3/M	1,974.90
AURORA ENERGY LLC	9/15/2015	18	7420	26.03	13.40	33.43	27.10	0.16	Bdl/GRP	I	3/M	1,735.35
AURORA ENERGY LLC	9/16/2015	17	7697	26.35	10.77	36.32	26.56	0.16	GRP/Bdl		M/6	1,681.25
AURORA ENERGY LLC	9/17/2015	17	7519	26.86	10.99	35.61	26.55	0.16	Bdl/GRP		6/M	1,555.60
AURORA ENERGY LLC	9/22/2015	19	7186	27.11	12.93	34.08	25.88	0.17	Bdl/GRP		6/M	1,877.05
AURORA ENERGY LLC	9/23/2015	18	7544	27.46	9.76	34.45	28.34	0.15	Bdl	I	3	1,812.45
AURORA ENERGY LLC	9/24/2015	6	7573	26.47	10.49	34.19	28.85	0.14	Bdl	I	3	604.35
AURORA ENERGY LLC	9/29/2015	6	7141	28.88	11.36	33.89	25.87	0.15	Bdl/GRP	I	3/M	603.55
AURORA ENERGY LLC	9/30/2015	5	7514	28.44	8.69	34.21	28.66	0.13	Bdl/Bdl	I	3/6	490.85
AURORA ENERGY LLC	10/1/2015	10	7360	29.29	9.35	33.72	27.64	0.14	Bdl/Bdl	I	3/6	949.70
AURORA ENERGY LLC	10/6/2015	17	7434	28.25	9.47	34.75	27.54	0.14	Bdl		6	1,697.60
AURORA ENERGY LLC	10/7/2015	16	7427	28.14	9.75	33.75	28.48	0.13	Bdl/STK	I	3/N	1,590.90
AURORA ENERGY LLC	10/8/2015	16	7766	28.02	6.97	35.04	29.97	0.14	Bdl/STK	I	3/N	1,550.35
AURORA ENERGY LLC	10/12/2015	12	7509	28.74	8.47	34.02	28.77	0.11	Bdl/JD	I	3/4	1,188.55
AURORA ENERGY LLC	10/13/2015	14	7448	29.46	8.57	34.10	27.88	0.11	Bdl/JD	I	3/4	1,378.00
AURORA ENERGY LLC	10/14/2015	15	7329	31.93	7.28	33.16	27.63	0.11	Bdl/JD	I	3/4	1,487.05
AURORA ENERGY LLC	10/15/2015	5	7435	31.66	6.81	34.31	27.23	0.11	JD		4	472.55
AURORA ENERGY LLC	10/16/2015	6	7723	31.20	5.10	35.54	28.17	0.11	JD		4	564.80
AURORA ENERGY LLC	10/20/2015	15	7561	31.93	5.92	34.77	27.38	0.11	JD		4	1,442.25
AURORA ENERGY LLC	10/21/2015	14	7609	31.67	5.47	34.54	28.32	0.11	JD		4	1,346.70
AURORA ENERGY LLC	10/22/2015	13	7492	32.01	6.01	34.29	27.70	0.11	JD		4	1,264.45

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Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	10/23/2015	15	7347	32.39	6.71	33.49	27.42	0.12	JD		4	1,492.50
AURORA ENERGY LLC	10/27/2015	9	7404	30.15	8.49	34.36	27.00	0.18	Bdl	J	4	910.80
AURORA ENERGY LLC	10/28/2015	11	7586	30.32	6.73	35.02	27.93	0.14	Bld/JD	J/	4/4	1,018.90
AURORA ENERGY LLC	10/29/2015	9	7861	26.44	7.92	36.05	29.59	0.19	Bdl	J	4	922.55
AURORA ENERGY LLC	10/30/2015	11	7948	26.92	7.00	36.90	29.19	0.17	Bdl	J	4	1,070.45
AURORA ENERGY LLC	11/3/2015	10	7438	27.87	10.34	34.56	27.24	0.28	Bdl/JD	J/	4/4	994.40
AURORA ENERGY LLC	11/4/2015	16	7495	29.67	8.21	34.18	27.95	0.20	Bdl	J	4	1,577.40
AURORA ENERGY LLC	11/5/2015	11	7320	29.67	9.27	33.61	27.46	0.22	Bdl	J	4	1,052.25
AURORA ENERGY LLC	11/6/2015	12	7629	27.60	8.75	35.23	28.42	0.25	Bdl/JD	J/	4/4	1,175.00
AURORA ENERGY LLC	11/10/2015	12	7640	28.50	7.97	35.25	28.29	0.19	Bdl	J	4	1,130.35
AURORA ENERGY LLC	11/11/2015	14	7865	27.22	7.50	35.71	29.58	0.21	Bdl	J	4	1,331.05
AURORA ENERGY LLC	11/12/2015	12	7797	27.25	7.73	35.48	29.54	0.23	Bdl	J	4	1,146.35
AURORA ENERGY LLC	11/13/2015	14	7947	26.11	7.79	36.51	29.60	0.19	Bdl	J	4	1,368.95
AURORA ENERGY LLC	11/17/2015	9	7760	27.53	7.86	35.47	29.14	0.20	Bdl/JD	J/	4/4	848.40
AURORA ENERGY LLC	11/18/2015	11	7705	28.38	7.44	35.64	28.55	0.18	Bdl/JD	J	4/4	1,026.00
AURORA ENERGY LLC	11/19/2015	8	7644	30.78	6.20	34.89	28.13	0.15	Bdl/JD	J	4/4	714.95
AURORA ENERGY LLC	11/20/2015	10	7783	29.27	6.29	35.70	28.73	0.15	JD/Bdl	/J	4/4	863.55
AURORA ENERGY LLC	11/23/2015	11	7793	29.35	6.29	35.57	28.79	0.15	JD		4	1,046.45
AURORA ENERGY LLC	11/24/2015	16	7682	30.62	5.97	34.92	28.49	0.12	JD		4	1,518.80
AURORA ENERGY LLC	11/25/2015	13	7770	29.54	6.19	35.63	28.65	0.14	JD/Bdl	/J	4/4	1,206.80
AURORA ENERGY LLC	11/27/2015	12	7612	28.41	7.98	35.68	27.94	0.19	Bdl/STK	J/	4/N	1,178.80
AURORA ENERGY LLC	12/1/2015	21	7514	29.25	8.35	34.58	27.83	0.20	Bdl/STK	J/	4/N	1,971.15
AURORA ENERGY LLC	12/2/2015	9	7587	30.48	6.72	34.32	28.49	0.16	JD		4	834.10
AURORA ENERGY LLC	12/3/2015	12	7577	32.45	4.74	33.98	28.84	0.10	JD		4	1,097.45
AURORA ENERGY LLC	12/4/2015	10	7503	31.28	6.60	33.78	28.35	0.12	JD		4	915.25
AURORA ENERGY LLC	12/8/2015	13	7594	29.65	7.36	34.53	28.47	0.17	Bdl/JD	J/	4/4	1,204.60
AURORA ENERGY LLC	12/9/2015	13	7627	28.50	8.21	34.71	28.58	0.23	Bdl/JD	J/	4/4	1,254.80
AURORA ENERGY LLC	12/10/2015	12	7651	29.18	7.10	35.18	28.55	0.17	Bdl/JD	J/	4/4	1,090.15
AURORA ENERGY LLC	12/11/2015	10	7159	33.74	6.25	34.17	25.84	0.14	JD		4	935.95
AURORA ENERGY LLC	12/15/2015	14	7591	31.15	5.91	35.16	27.78	0.15	Bdl/JD	J	4/4	1,235.25
AURORA ENERGY LLC	12/16/2015	14	7527	31.73	6.00	35.00	27.27	0.16	Bdl/JD	J	4/4	1,288.80
AURORA ENERGY LLC	12/17/2015	14	7639	29.80	6.85	35.24	28.12	0.16	Bdl/JD	J	4/4	1,258.85

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Analysis Results for 7/1/15 to 12/31/15

AURORA ENERGY LLC	12/18/2015	14	7571	30.68	6.58	34.72	28.03	0.13	Bdl/JD	J	4/4	1,314.95
AURORA ENERGY LLC	12/21/2015	14	7631	30.24	6.30	35.17	28.29	0.15	Bdl/JD	J	4/4	1,318.90
AURORA ENERGY LLC	12/22/2015	14	7549	31.19	5.71	34.71	28.39	0.13	Bdl/JD	J	4/4	1,250.95
AURORA ENERGY LLC	12/23/2015	14	7686	31.43	4.63	35.27	28.68	0.10	Bdl/JD	J	4/4	1,262.70
AURORA ENERGY LLC	12/24/2015	10	7627	31.52	4.92	35.64	27.93	0.11	Bdl/JD	J	4/4	933.25
AURORA ENERGY LLC	12/28/2015	14	7714	30.71	4.93	36.01	28.36	0.11	Bdl/JD	J	4/4	1,246.45
AURORA ENERGY LLC	12/29/2015	16	7780	30.08	5.31	35.97	28.65	0.12	Bdl/JD	J	4/4	1,424.70
AURORA ENERGY LLC	12/30/2015	11	7673	31.40	5.02	35.64	27.95	0.12	Bdl/JD	J	4/4	968.20
AURORA ENERGY LLC	12/31/2015	12	7705	31.63	4.47	35.57	28.34	0.12	Bdl/JD	J	3/4	1,059.70

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	120758.30	7610.00	29.02	7.69	35.09	28.20	0.15

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 1-7-16

Coleen Thompson

Signature