September 24, 2019

Via Email to: Lreisig@crystalsugar.com
(No Hardcopy to follow)

Mr. Lincoln Reisig
Sidney Sugars Incorporated
35140 County Road 125
Sidney, MT 59270

SUBJECT: Response to the Regional Haze Source Screening letter from the Montana Department of Environmental Quality (MDEQ) dated March 14, 2019 to Sidney Sugars Incorporated (SSI).

Dear Lincoln:

I (Kevin Walsh), and Environmental Consulting Services, LLC (ECS), are pleased to submit the enclosed response concerning the Regional Haze Source Screening letter from the Montana Department of Environmental Quality (MDEQ) dated March 15, 2019 to Sidney Sugars Incorporated (SSI). First of all, it is evident that MDEQ does not have all of the correct, and proper, emission factors (Efs) on the Annual Emission Inventory for your equipment at your facility, and this was previously described and noted in my April 1, 2019 letter to you. In addition, due to these corrected Efs, then MDEQ has incorrectly evaluated the Q/d screening for your facility. Further explanation and documentation follows.

The Annual Emission Inventory submission performed by SSI personnel is "on-line" on the MDEQ website, and the Efs are "locked in" by MDEQ (which means only MDEQ can change these Ef values). SSI personnel completed the annual emission inventory for each "emitting unit" (EU) identified at your facility on the MDEQ web-based system. The facility is then charged, annually, according to the tons of criteria pollutants emitted. MDEQ also used this annual emission inventory to assess the SSI facilities potential to contribute to Regional Haze, with specifically looking at SO_2 and NO_X emissions. SO_2 and NO_X emissions are generated by the combustion of fossil fuels, whether in solid form or gaseous form. Seven (7) EUs were identified at your facility that emit SO_2 and NO_X, and MDEQ looked at the average for the years of 2014-17 for their screening purposes for Regional Haze. The Efs that are used come from various publications/sources including but not limited to AP-42 and FIRE database. While reviewing the Efs for the 7 EUs, it came to my attention that some Efs that were being used within the Annual Emission Inventory by MDEQ were incorrect, and thus were generating larger ton per year (TPY) emissions for NO_X emissions than what should have been calculated.

Emitting Unit	Source	SCC	Size	MDEQ Ef	Corrected Ef
EU001	CE Boiler 1	10200306	92-115 MMBtu	5.8	4.06
EU002	CE Boiler 2	10200306	92-115 MMBtu	5.8	4.06
EU003	Union Boiler 3	10200601	110-130 MMBtu	190	190
EU005	Union Boiler 4	10200602	65-83 MMBtu	140	100
EU007	Superior Mohawk Boiler	10200602	20-25 MMBtu	140	100
EU0024	Pulp Dryer 1	39000689	65-95 MMBtu	190	100
EU0025	Pulp Dryer 2	39000689	65-95 MMBtu	190	100
EU030	CBW-600 Boiler	10200602	20 MMBtu	91.8	91.8

Notes: SCC = Source Classification Code
EU007 has been removed from the site as of 2017 and is no longer a part of the Annual Emission Inventory
EU030 was added to the site in 2017 to replace EU007

An explanation of the corrected Efs:

- For EU001 and EU002, the corrected Ef is due to the operational configuration of "over-fire air" (OFA), which is described in the most updated AP-42 manual as a "NO_X control" that is 20-30% effective in reducing emissions. This control measure was described and noted in the 2012 Energy Assessment document developed by Stan Selle for the SSI CE Boilers.
- For EU005; EU007; EU0024; and EU0025, the corrected Ef is due to updated information in both AP-42 and the FIRE database that lowered the Ef from 140 and/or 190 to 100. Also, it appears that MDEQ incorrectly classified EU0024 and EU0025 (the Pulp Dryers) at a higher Ef than should have been.
- Efs are based on the SCC as well as the size of the EU.

Excel spreadsheets are attached that demonstrate the MDEQ calculated values of NOx and the corrected values for NOx. The "2014-17 average" NO_X TPY emissions, as shown on the MDEQ letter, was 210.75, while the corrected average NO_X TPY emissions for 2014-17 (using the corrected Efs as shown above) is 151.53, a reduction of 59.22 TPY average.

The MDEQ letter performed an SO_2 and NO_X Emissions Screening Analysis using the 2014-17 SO_2 and NO_X averages, with their result showing a value of 5.18 using the calculation routine of Q/d, where Q= SO2 + NOX and d = distance to nearest Class I Area. When using the corrected Efs (as shown above and on the attached spreadsheets) the 2014-17 SO_2 and NO_X average, the **Emissions Screening Analysis value becomes 4.04**.

FOUR FACTOR ANALYSIS - GENERAL APPLICABILITY

Although it would appear that "No Further Actions" should be required for SSI for the Regional Haze Program due to the Emission Screening Analysis value of 4.04, a Four Factor Analysis has been performed for NOx emissions for the four major emitting sources at SSI identified in the MDEQ letter, with the results shown herein.

Four NOx major emitting sources at SSI
CE Boiler #1
CE Boiler #2
Union Boiler #3
Union Boiler #4

To accomplish the requested Four Factor Analysis for NOx emissions for the above identified emitting units (EUs), and due to the fact that these EUs are operated by a beet sugar manufacturer, of which there are few in the United States, then certain publically available information regarding this issue specific to beet sugar manufacturing have been reviewed and used within this submittal, in specific the "Amec Foster Wheeler Environmental & Infrastructure, Inc.; Final Four Factor Analysis for Regional Haze in the Northern Midwest Class I Areas, dated October 27, 2015" document (Amec document).

A summary of the results from the Four Factor Analysis of the Amec document indicates that Industrial, Commercial, and Institutional (ICI) Boilers at Sugar Beet Manufacturing Facilities have: an average cost (in 2015 dollars) of \$450-\$17,000 per ton of NOx reduction; a compliance timeframe of 2-5 years following SIP submittal; energy and non-air quality environmental impacts of efficiency loss, increased fuel consumption, solid waste disposal, reagent storage, and ammonia slip; and a remaining useful life of 10-30 years.

NOx from Industrial, Commercial, and Institutional Boilers at Sugar Beet Manufacturing Facilities

NOx Emissions and Control Options

Nitrogen oxides are a by-product of combustion. Nitrogen is inherently contained in fuels and in the air and does not react at low temperatures. During combustion, the high temperatures cause the nitrogen and oxygen in the air to react and form NOx. The amount of NOx formed is dependent on many factors including the type of fuel combusted, temperature, and residence time of the air. NOx formation can be classified into the following four categories: thermal NOx, fuel NOx, feed NOx, and prompt NOx. Thermal NOx is formed from nitrogen and oxygen in the air as a result of high temperature. Thermal NOx formation has a positive correlation with temperature. Fuel NOx is the result of nitrogen contained in organic fuels releasing and reacting with oxygen. Some fuels, such as natural gas, typically have no bound nitrogen, however, others such as coal or oil can contain high amounts. Feed NOx is caused by reaction of the nitrogen in feed materials in a process, such as the constituents of cement, in a high temperature environment. Feed NOx is not usually a concern for boilers. Prompt NOx is formed as atmospheric nitrogen, atmospheric oxygen, and hydrocarbons from the fuel rapidly react. It is a minor contributor to overall NOx formation.

Due to the multiple factors affecting NOx formation from combustion, there are different methods of reducing or controlling NOx emissions. The potential control types analyzed can be categorized into the following two categories: combustion modifications and post-combustion NOx controls. Combustion modifications are changes to one or more controllable variables in the combustion process itself, such as temperature and combustion air residence time. Post combustion NOx controls utilize add-on control technologies to decrease the amount of formed NOx before the combustion air is release to the atmosphere. It should be noted that the potentially applicable controls for any one source are highly dependent on the type of boiler, fuel(s) used, heat input capacity, and mode of operation. A summary of the potential NOx control options is provided in Table 1.

Table 1
Potential NOx Control Options for Industrial, Commercial, and Institutional Boilers at Sugar Beet Manufacturing Facilities

Technology	Description	Applicability	Performance
Boiler Tuning/Optimization	Adjust air to fuel ratio	Potential control measure of all boilers	5-15% reduction in NOx
LNB	Low NOx burners	Potential control measure for all boilers; dependent upon fuels burned, boiler use, and boiler configuration	40-50% reduction in NOx
ULNB	Ultra low NOx burners	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	45-85% reduction in NOx
LNB+FGR	Low NOx burners and flue gas recirculation	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	50-70% reduction in NOx
LNB+OFA	Low NOx burners and over-fired air	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	40-60% reduction in NOx
SCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	70-90% reduction in NOx
SNCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	10-70% reduction in NOx
RSCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers	Potential control measure for all boilers; dependent on boiler configuration	60-75% reduction in NOx

Combustion Modification

Boiler Tuning/Optimization

One method of combustion modification to control NOx from boilers is “tuning,” also known as optimization. The air to fuel ratio for combustion is analyzed and adjusted to lower NOx emissions. This may also result in more efficient combustion and better boiler performance. The reduction efficiency possible through boiler tuning is dependent on how “de-tuned” the boiler was prior to optimization, but 5 to 15 percent reduction of NOx can be achieved.

Low/Ultra Low NOx Burners

Low NOx burner (LNB) technology utilizes alternate burner designs to reduce the formation of NOx. Temperature, residence time, and oxygen levels can be altered from traditional burner designs. LNBs utilize staged combustion, where fuel is introduced to an oxygen-rich, low temperature zone, and any uncombusted fuel is burned in a lower oxygen zone. In addition, the surface area of LNBs is increased to lower flame temperature and reduce thermal NOx production. Ultra Low NOx Burners (ULNB) often use similar designs and can decrease NOx emissions to up to 85 percent, and LNBs can decrease NOx emissions on average by 40 to 50 percent. LNBs are often combined with other combustion modification controls like flue gas recirculation and over-fired air. LNBs can result in significantly lower efficiencies, depending on the boiler and burners chosen. Suitability of LNBs must be carefully analyzed for each individual boiler.

Flue Gas Recirculation

Flue gas recirculation (FGR) returns a portion of post-combustion stack gas to the burners. This lowers the oxygen content of the combustion air and decreases the flame temperature, thus less thermal NOx is formed. FGR is often combined with LNBs and can reduce emissions by 50 to 72 percent for coal and oil fired boilers. Retrofitting an FGR system to a boiler is sometimes challenging or infeasible, depending on the unit.

Over-fired Air

Over-fired air (OFA) is a form of staged combustion that works by directing a portion of the combustion air from the last burners to ports downstream. This creates a more fuel-rich environment near the burners. Less thermal NOx is formed due to lowered temperatures at the combustion zones and less oxygen near the burners. OFA can be combined with LNBs to reduce NOx emissions by 40 to 60 percent.

Post-Combustion NOx Controls

<u>Selective Non-Catalytic Reduction</u>
Selective Non-Catalytic Reduction (SNCR) removes NOx by injecting urea or another reducing agent into the flue gas. The reagent reacts with NOx to form nitrogen gas (N2) and water. Temperatures between 1,700 and 2,000 °F are optimal for the reaction. SNCR systems can reduce NOx emissions by 30 to 60 percent. The use of LNBs with an SNCR system can increase the reduction efficiency to 50 to 90 percent of NOx.

<u>Selective Catalytic Reduction</u>
Selective Catalytic Reduction (SCR) is similar to SNCR in that it removes NOx by injecting a reducing agent (typically ammonia) into the flue gas; however, SCR utilizes a catalyst. The catalyst lowers the activation energy needed for the reaction of NOx and ammonia to form nitrogen gas and water. As a result, SCRs are appropriate for boilers with lower flue gas temperatures. Depending on the catalyst used, temperatures of 470 to 1000 °F are required for proper reduction of NOx. Below this range, unreacted ammonia is released to the atmosphere, and above this range, ammonia oxidizes to form additional NOx. A properly maintained SCR system can reduce NOx emissions by 70 to 90 percent, more than an SNCR system, but have lower operating costs and higher capital costs. A boiler operator may also install ULNB with an SCR system to decrease NOx emissions by up to 95 percent.

<u>Regenerative Selective Catalytic Reduction</u>
Regenerative Selective Catalytic Reduction (RSCR™) is an alternative to SCR for smaller boilers or boilers with particulate control equipment upstream of the control device. An SCR system requires a minimum flue gas temperature of 470 °F which may not be possible for some boiler systems. An RSCR system utilizes ceramic heat exchangers and a burner to bring the flue gas up to a suitable temperature for the reaction of NOx and ammonia (or similar reducing agent) to occur. NOx reduction efficiencies of 60 to 75 percent of can be achieved.

Four Factor Analysis of Potential NOx Control Scenarios for Industrial, Commercial, and Institutional Boilers at Sugar Beet Manufacturing Facilities

Cost of Compliance

It is important to note that the values provided are estimated and actual retrofit control costs may be higher or lower depending on the utilization and size of the individual boiler as well as specific capital costs associated with the design. Combustion modifications are generally low cost in comparison to post combustion controls. Costs from boiler tuning include engineering and contractor costs to measure the oxygen and carbon monoxide concentrations in the flue gas and adjust the air to fuel mixture appropriately. LNBs and ULNBs are generally cost effective but the impacts on boiler efficiency must be considered. Associated costs are from engineering, the burners and related equipment, and labor costs for installation. Costs from retrofitting FGR or OFA can vary greatly depending on the boiler design. Engineering, equipment such as piping and fans, and labor costs make up the bulk of the costs. If extensive changes to the boiler are required to retrofit FGR or OFA, the costs can easily exceed cost effective levels.

Post-combustion NOx controls are generally much more cost intensive than combustion modifications, but can provide significantly higher reductions in NOx. The applicability of each type of post-combustion control should be carefully assessed for each unit. Considerations include space constraints, flue gas temperature, if fly ash is sold (the reducing agent may contaminate fly ash depending on the system chosen), and load swings of the boiler. For boilers with high temperature flue gas streams, an SNCR system may be considered. No reactor is required for SNCR as the urea or other reducing agent can be injected directly into the flue. This reduces capital costs for the system; however, operating costs are higher due to lower efficiency and more reagent use. For boilers with flue gas stream temperatures lower than those required for SNCR system, SCR and RSCR systems may be viable. They have high capital costs as a result of the dedicated reactor and catalyst required for each system; however, reagent costs are lower than for an SNCR system and NOx reduction efficiency is greatly increased.

Table 2 summarizes the cost effectiveness and factors affecting cost of each control option addressed in this analysis. Costs are shown in 2015 dollars. Please note that some costs may have increased or decreased.

Table 2
Cost Effectiveness for NOx Control Options for ICI Boilers at Sugar Beet Manufacturing Facilities

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Boilers
Boiler Tuning/Optimization	None	Low	Engineering and contractor costs	All Boilers
LNB	None	$450-$3,700	Equipment, installation, and engineering	All Boilers
ULNB	None	$650-$2,200	Equipment, installation, and engineering	All Boilers
LNB+FGR	None	$1,200-$4,300	Equipment, installation, construction, and engineering	All Boilers
LNB+OFA	None	$700-$3,700	Equipment, installation, construction, and engineering	All Boilers
LNB+SNCR	Urea injection system	$1,700-$4,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All Boilers; dependent on temperature
ULNB+SCR	Ammonia injection system	$2,900-$5,100	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All Boilers; dependent on temperature
SCR	Ammonia injection system	$2,600-$17,000	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All Boilers; dependent on temperature
SNCR	Urea injection system	$1,500-$4,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	All Boilers; dependent on temperature
RSCR	Ammonia injection system	$1,800-$5,300	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All Boilers; dependent on temperature

Time Necessary for Compliance

Sources are generally given between two and five years to implement changes for compliance with new regulations. MACT standards typically allow three years for compliance, and BART emission limitations require compliance no more than five years after regional haze SIP approval by the EPA. Combustion modifications and post-combustion NOx controls require significant time for engineering, construction, and facility preparedness. Two to five years after SIP approval would typically be appropriate, depending on the size of the unit and control options selected. Substantially less time would be required for boiler optimization and tuning which can be implemented within a few months to a year.

Energy and Non-Air Impacts

Combustion modification and post-combustion NOx controls can impact energy use and the environment in forms other than air quality. Non-air environmental impacts include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water. Some control technologies may result in nuisances in the form of noise pollution or odor.

Combustion modifications can have significant impacts on energy use, positively or negatively. Boiler tuning, LNB/ULNBs, OFA, and FGR can reduce the efficiency of a boiler as the air to fuel ratio increases and temperature decreases. This increases fuel usage and, as a result, costs. OFA and FGR systems increase energy use in the form of fans and compressors. Facilities that sell fly ash may be affected due to the higher CO concentrations making the fly ash unsuitable for sale.

Post-combustion NOx controls may also impact energy use for boilers. SCR, SNCR, and RSCR systems reduce thermal efficiency by using thermal energy in the reaction of NOx and reagent. Fans, compressors, injection equipment, and related processes utilize energy and increase costs. For SCR, SNCR, and RSCR systems, the reagent (usually ammonia or urea) can contaminate fly ash, making it unsalable.

Remaining Useful Life at the Source

The remaining useful life of an individual boiler can vary greatly depending on the age of the boiler, size of the unit, maintenance frequency, and other factors. Life expectancies for most industrial, commercial, and institutional boilers at sugar beet manufacturing facilities are between 10 and 30 years or more.

FOUR FACTOR ANALYSIS – SSI SPECIFIC

Cost of Compliance

Table 3
Cost Effectiveness for NOx Control Options for ICI Boilers at SSI

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Boilers
Boiler Tuning/Optimization	None	Low	Engineering and contractor costs	All Boilers
LNB	None	$450-$3,700	Equipment, installation, and engineering	All Boilers
ULNB	None	$650-$2,200	Equipment, installation, and engineering	All Boilers
LNB+FGR	None	$1,200-$4,300	Equipment, installation, construction, and engineering	Union Boilers only
LNB+OFA	None	$700-$3,700	Equipment, installation, construction, and engineering	All Boilers
LNB+SNCR	Urea injection system	$1,700-$4,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
ULNB+SCR	Ammonia injection system	$2,900-$5,100	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
SCR	Ammonia injection system	$2,600-$17,000	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
SNCR	Urea injection system	$1,500-$4,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	Not Applicable-Infeasible, stack temps too low
RSCR	Ammonia injection system	$1,800-$5,300	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low

It is evident, from the information shown above, that “combustion modifications” are the only potential options for the affected EUs (CE Boilers and Union Boilers) for NOx control at the SSI facility.

Time Necessary for Compliance
Two to five years after SIP approval, and notification from MDEQ, would be required.

Energy and Non-Air Impacts
Non-air environmental impacts include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water. Combustion modifications would have significant negative impacts on energy use. Boiler tuning, LNB/ULNBs, OFA, and FGR would reduce the efficiency of a boiler as the air to fuel ratio increases and temperature decreases. This increases fuel usage and, as a result, costs. OFA and FGR systems increase energy use in the form of fans and compressors.

Remaining Useful Life at the Source
Life expectancy for the SSI CE Boilers and Union Boilers are estimated at between 10 and 30 years or more.

REPLACE CE BOILERS WITH NATURAL GAS FIRED BOILERS OPTION

There remains a potential option to replace the CE Boilers (i.e., coal fired boilers) with natural gas fired boilers. This potential option may be enacted by SSI depending upon the availability of the nearby lignite coal source (i.e., the Savage Coal Mine) and the economic costs of the availability of another coal source as compared to replacing the CE Boilers with natural gas fired boilers. This potential option does have some environmental benefits as related to both air quality emissions and solid waste generation (i.e., fly ash), however the economics of this potential option would need to be fully addressed internally by SSI.

To replace the two CE Boilers with natural gas fired boilers, I estimate that it would require two natural gas fired boilers of between 120 to 180 MMBtu/hr size for each boiler. Replacing these boilers will require an Air Quality Pre-Construction Permit and a modification to the facilities Title V Air Quality Operating Permit. At this time I have determined that two distinct, and separate, federal/state air quality regulations will be triggered by enacting this potential option, however there may be other regulations that may affect permitting natural gas fired boilers as well, with these two regulations identified as:

1. 40 CFR Part 60, Subpart Db – Standards of Performance for Large Industrial-Commercial-Institutional Steam Generating Units.
2. ARM Title 17 Chapter 8-Air Quality, Subchapter 8 – Prevention of Significant Deterioration

There is an emission standard for NOx in Subpart Db, which is 0.2 lb/MMBtu. Feel free to use this information, in any way you determine, to provide a response to MDEQ.

If you should have any questions please contact me.

Respectfully submitted,

Kevin K. Walsh

Kevin K. Walsh
Consultant

cc: Jason Vollmer, ECS (via email)
David Garland (via email)
Ray Carlson (via email)

Attachment