Regional Haze
Four-Factor Analysis

F. H. Stoltze Land and Lumber Company
Columbia Falls Sawmill

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EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by F.H. Stoltze Land & Lumber Company (Stoltze) to prepare a four-factor analysis for the biomass-fired boiler located at their Sawmill facility located in Columbia Falls, Montana. The four-factor analysis was requested by the Montana Department of Environmental Quality (MDEQ) in an email dated March 15, 2019.

The analysis itself relates to "Round 2" of development of a State Implementation Plan (SIP) to address regional haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the four-factor analysis is to determine if there are emission control options at Stoltze that, if implemented, could be used to attain "reasonable progress" toward the state's visibility goals.

The four-factor analysis was conducted for control of oxides of nitrogen (NO_x) from the biomass-fired boiler at the Stoltze sawmill along with a more limited sulfur dioxide (SO_2) control discussion. The results of the analysis have indicated that additional NO_x and SO_2 controls on the Wellons boiler are not necessary to make reasonable progress toward the state's visibility goals. The cost effectiveness of additional emissions controls is not suitable for requiring installation of the controls. Review of visibility monitoring data shows that the Stoltze boiler does not contribute measurably to visibility reduction at any nearby Class I area. It is concluded that this facility does not qualify for additional emission controls or limitations based on the four-factor analysis.

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1.0 ACRONYMS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Bison	Bison Engineering, Inc
Btu	British Thermal Unit
CAA	Clean Air Act
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
Control Cost Manual	EPA Air Pollution Control Cost Manual
dV	Deciview
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
GNP	Glacier National Park
HHV	Higher Heating Value
IMPROVE	Interagency Monitoring of Protected Visual Environments
lb/MMBtu	Pounds per Million British Thermal Units
lb/hr	Pounds per Hour
m	meters
MDEQ	Montana Department of Environmental Quality
MMBtu/hr	Million British Thermal Units per Hour
MMBtu/MW	Million British Thermal Units per Megawatt
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
(NH4)2SO4	Ammonium Sulfate
NPHR	Net Plant Heat Input Rate
NSR	Normalized Stoichiometric Ratio
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
RHR	Regional Haze Rule
Round 1	First planning period of the Regional Haze Program
Round 2	Second (current) planning period of the Regional Haze Program
RPG	Reasonable Progress Goals
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
Stoltze	F.H. Stoltze Land & Lumber Company
TPY	Tons per year
TSD	2008 Electric Generating Unit NO_x Mitigation Strategies Proposed Rule Technical Support Document
USGS	United States Geographical Survey
UTM	Universal Transverse Mercator
WRAP	Western Regional Air Partnership

2.0 INTRODUCTION

2.1 Basis of Four-Factor Analysis Request

As part of the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal "… the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." (42 USC 7491(a)(1)). With that goal, plans and requirements were eventually codified in the Code of Federal Regulations (CFR) primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 to 309). These requirements state individual states are required to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 (40 CFR 51.308(d)(1)).

The Environmental Protection Agency (EPA), via a Federal Implementation Plan (FIP) promulgated the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) and a four-factor analysis for various sources in Montana.[1] The first planning period of the Regional Haze Program (Round 1) analysis was performed before Stoltze replaced their old boilers with the current Wellons boiler. The Stoltze facility was not included in the FIP because it does not have the potential to emit 250 tons per year (tpy) or more of a visibility-impairing pollutant.

A second round of obligations (Round 2) is now under development, with MDEQ moving into the role as the lead agency. Round 2, or planning period as it is sometimes referred, requires an additional step toward 'reasonable progress' in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. The Regional Haze Rule (RHR) as outlined in 40 CFR 51.308 *et seq*. identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These four factors are collectively known as the four-factor analysis and are as follows:

- *Factor 1*. Cost of compliance
- *Factor 2*. Time necessary for compliance
- *Factor 3*. Energy and non-air quality environmental impacts of compliance
- *Factor 4*. Remaining useful life of any existing source subject to such requirements

MDEQ contacted Stoltze by letter dated March 15, 2019 to describe the steps for implementation of the four-factor analysis requirement. Based on review of the emissions from the Stoltze facility, Bison has determined that the four-factor analysis should be limited to NO_x and SO_2 emissions from the Stoltze boiler. In a May 28, 2019 email, MDEQ requested a "representative baseline" emissions period on which to base regional modeling as a part of the Round 2 planning period efforts. Stoltze and MDEQ agreed on

[1] The FIP was promulgated on Sept. 18, 2012 at 77 FR 57864.

the average of the 2017 and 2018 annual emission years as that representative baseline. The correspondence between MDEQ and Stoltze is included in *Appendix A* of this report. Those 2017-2018 annual emissions years are also used as a basis for this four-factor analysis.

2.2 F. H. Stoltze Facility Information

Stoltze owns and operates a sawmill facility located near Columbia Falls, Montana. Equipment at the sawmill includes a biomass-fired boiler which supplies steam for lumber drying and for steam-powered electrical generation. The Stoltze boiler was manufactured by Wellons Inc. in 2012 and is referred to as the Wellons boiler. Biomass combustion in the Wellons boiler produces potentially visibility impairing combustion gases including NO_x and SO_2.

The lumber mill site has an area of 149 acres and is located at 600 Halfmoon Road, Columbia Falls, Montana. The legal description of the site location is SE½ of Section 2, Township 30 North, Range 21 West, in Flathead County, Montana. The Universal Transverse Mercator (UTM) coordinates of the boiler stack are Zone 11, NAD 83 datum, easting 704,032 meters (m), and northing 5,363,089 m, and the geographical coordinates are 48.388 north latitude and 114.244 west longitude[2]. The site elevation is 3,064 feet above mean sea level.

A USGS topographic map is included as *Figure 1* showing the site location. *Figure 1* also shows the boundary of Glacier National Park (GNP), which is the nearest Class I area to the Stoltze facility. *Figure 2* is a printout of a Google Earth satellite photo of the area surrounding the facility, with the site location indicated.

[2] Site coordinates based on boiler stack location, as determined from Google Earth

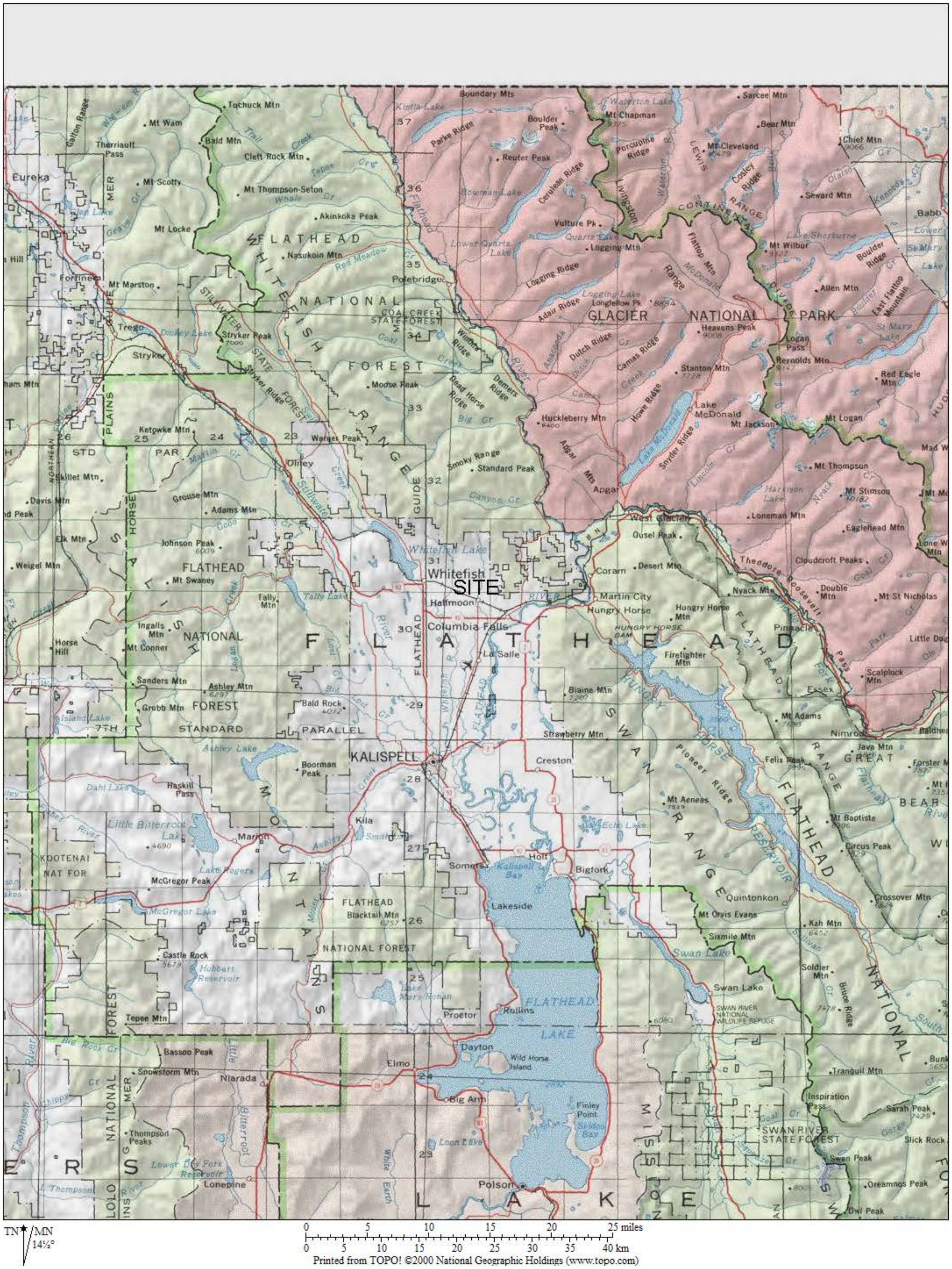

Figure 1: Topographic Map of Site in Relation to Nearest Class I Area

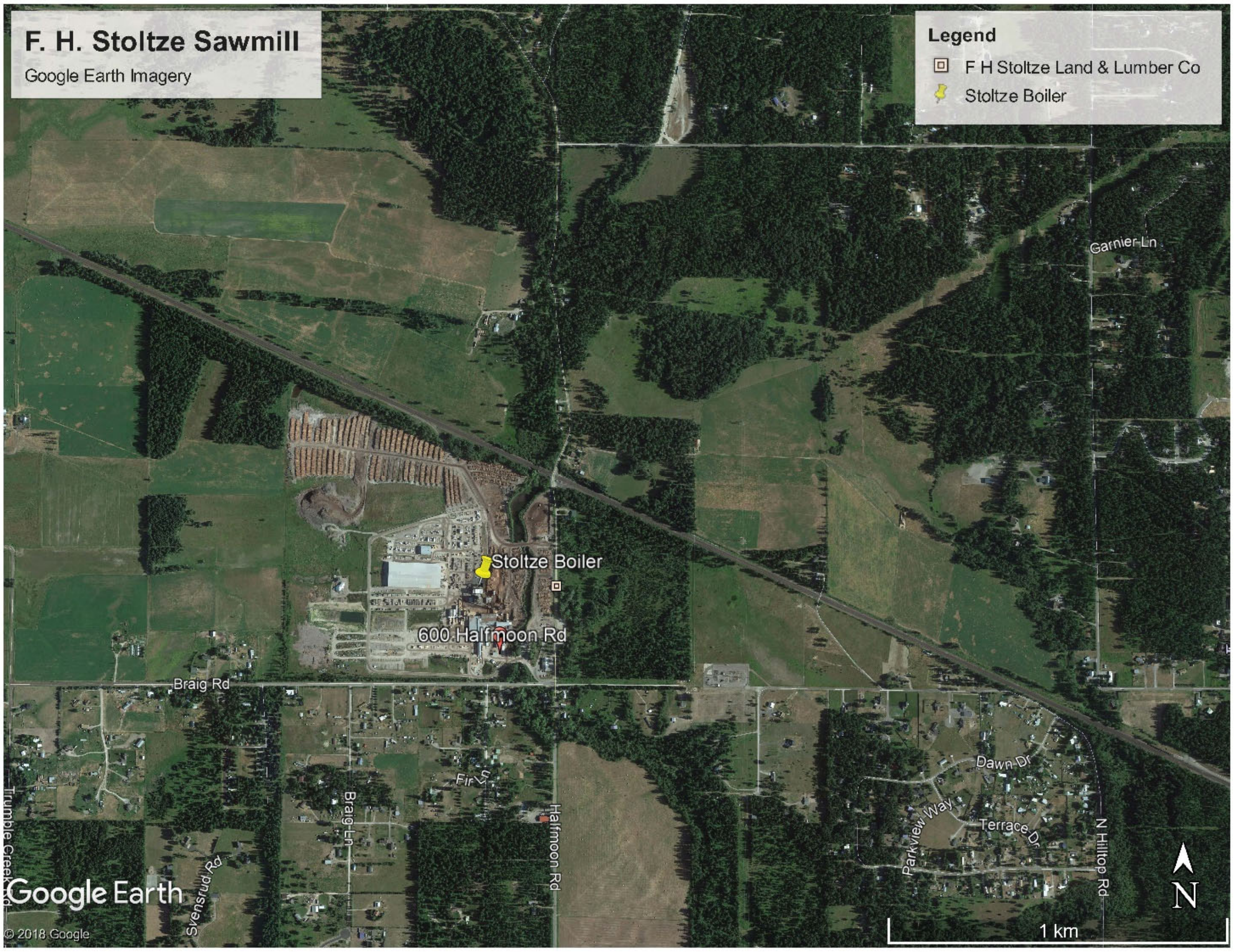

Figure 2: Google Earth Representation of Stoltze Facility

3.0 PROGRAM SUMMARY and STATUS

As previously stated, the Regional Haze program is an attempt to attain ‘natural’ (nonanthropogenic) visibility conditions in all mandatory Class I areas[3] by 2064. The RHR itself was promulgated in substantially its current form in 1999 with adjustments made in 2017. The rule has been implemented in incremental steps. The first step, or sometimes referred to as the 1st planning period (Round 1), was a combination of BART and a four-factor analysis. During this initial planning period BART applied to certain older facilities and the four-factor program, applied to ‘larger’ facilities who had a potential of impacting (visibility) in a mandatory Class I area. Stoltze was excluded from both analyses under Round 1.

3.1 Montana Initiatives

For Montana, Round 1 requirements were executed via the EPA during the period of 2006 to 2018. In July 2006, Montana determined that it no longer had the resources to complete the requirements of the program and thus returned the program to EPA. Following much discussion and analyses, EPA six years later promulgated a FIP as it applied to sources in Montana. As previously discussed, Stoltze was not included in the FIP, therefore, no additional or new controls were required for Stoltze for the Round 1 planning period.

Given the timeframe for Round 1 has expired, the RHR now requires the implementation of Round 2. Round 2 is meant to show an incremental progress toward the national goal for the 10-year period 2018 to 2028. Additional 10-year implementation periods will follow until the national goal is achieved (40 CFR 51.308(f)).

Recently MDEQ elected to bring the program back to state control. With that decision, MDEQ is taking the lead in the development of the four-factor analyses and plans associated with the second planning period. As is stands, MDEQ is attempting, by July 2021, to submit a SIP to EPA with the enforceable reductions (emission limits or plans that will go into effect prior to 2028).

To implement the program fully, it was first necessary to measure regional haze (visibility and its constituents) data in the identified Class I areas. This has been an ongoing effort via various ambient monitoring programs. Among them is the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [1]. This visibility monitoring program began in 1988 and continues to be a cooperative effort between EPA and various federal land managers (primarily the National Park Service and the US Forest Service).

The results of the IMPROVE monitoring have indicated, for Glacier National Park, the primary pollutants that account for the most anthropogenic visibility degradation are (ammonium) sulfate (ammonium) nitrate [2,3]. The primary pollutant that

[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977. Montana has 12 (of 156) such areas.

accounts for most non-anthropogenic visibility degradation is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air. Organic carbon is the largest contributor to light extinction at nearly all sites on the worst days, while sulfates are the largest contributor to light extinction on the best days. The large contribution of organic carbon is likely due to summer wildfire activity [4].

For Round 2, MDEQ has elected to look for reductions in SO_2 and NO_x (precursors to ammonium sulfate and ammonium nitrate) emissions. The sources chosen for the analysis are those facilities whose emissions-to-distance (from the Class I area) ratio exceeds a particular value as noted below:

If Q/d > 4, then the facility is chosen for a 4-Factor analysis

Q = mean annual emissions from 2017-2018 of SO_2 + NO_x (tons)

d = distance to the nearest mandatory Class I area (kilometers)

The calculated Q/d ratio for the Stoltze boiler and Glacier National Park was 5.37, indicating that the boiler could potentially be contributing to visibility reduction and may require further analysis. Therefore, MDEQ has requested Stoltze conduct a four-factor analysis for the Wellons biomass-fired boiler to assess potential reductions in SO_2 and NO_x emissions (*Appendix A*). The Q/d ratio for the Stoltze boiler and all other Class I areas is much less than 4.0.

3.2 Federal Initiatives

Because this request for information arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements.

A visibility program aimed at attaining national visibility goals in mandatory Class I areas was authorized in Section 169A of the Clean Air Act (42 USC 7491). The national goals are to be attained by the year 2064, approximately 45 years from now. The rules which are to implement this goal of protecting visibility are found at 40 CFR 51, Subpart P (subsections 300 through 309). A review of Subpart P indicates the purpose and goals of the program. The purposes of the program are outlined as follows:

> "*The primary purposes of this subpart are . . .to assure* ***reasonable progress*** *toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment* ***results*** *from manmade air pollution. . ."* [40 CFR 51.300(a)].

The visibility program may be thought of as the implementation of two sub-programs. One regards new source review permitting and the other addresses "regional haze." Regional haze may further be broken down into the BART program and the reasonable progress program. The underlying reason stated for MDEQ's March 15, 2019 letter and other correspondence to Stoltze relates to reasonable progress achieved through the four-factor analysis.

In that regard, the RHR outlines what it refers to as: "the core requirements" for the implementation of the regional haze goals. More specifically, 40 CFR 51.308(d)(1) states:

> "*For each mandatory Class I Federal area..., the State must establish goals... that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days..."*

The rules go on to provide the states with a list of what must be considered in developing reasonable progress. Among these details are the four-factor analysis that is outlined above in *Section 2.1* and in the March 15, 2019 letter (*Appendix A*).

3.3 Overall Applicability

Montana is tasked to establish (a plan for) reasonable progress in carrying out the visibility protection. *Section 2.1* outlines the purpose of the program along with core elements. To that end, MDEQ seeks a "*detailed review of additional process controls"* which is assumed to be evaluated by both Montana and EPA for applicability in establishing a set of specific, reasonable Montana control strategies that create reasonable progress toward the 2064 goals.

The purpose of the program is to protect visibility by remedying, reducing, and preventing man-made impairments (or activities) over time in mandatory Class I areas. Reasonable progress expresses the notion that states must have implementation plans to approach the national goal by 2064 along a 'glide-path' of improvements to visibility, with certain exceptions. Based on the language contained in 40 CFR 51.300(d)(1), it can be ascertained that any activity, remedy or control (proposed or otherwise) that does not reasonably improve visibility in a mandatory Class I area is not a rational candidate for those reasonable progress goals [5]. That sentiment is confirmed in Section II.A EPA August 20, 2019 guidance [6]:

> *"The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas. As a general matter, this process involves a state evaluating what emission control measures for its own sources, groups of sources, and/or source sectors are necessary in light of the four statutory factors, five additional considerations specified in the Regional Haze Rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress."*

As a result, an analysis that only considers one or more emission control options is not enough for inclusion into reasonable progress mandates unless those emission controls are expected to improve actual visibility in a Class I area in a discernible manner. It is neither necessary nor appropriate to include an emission control as part of a reasonable progress goal or plan without a reasonable expectation of a resulting improvement in regional haze as a direct result of the application of the control (i.e., a discernible improvement in deciviews[4] in a Class I area.

To that end, Stoltze has elected to not only analyze various control "options" utilizing four factors but has also included a qualitative analysis of impacts the Stoltze facility in Columbia Falls may have on the closest Class I Area, Glacier National Park. This was accomplished to determine if either the current configuration or future control options would fulfill the underlying need of the program to "***provide for an improvement in visibility*"** at a mandatory Class I area [7].

As will be presented in following sections of this document, no measured evidence of any impact by Stoltze operations on the visibility at Glacier National Park was established.

[4] The definition of a deciview is as follows: Deciview haze index=10 $\ln_e(b_{ext}/10\ Mm^{-1})$. This is taken from the definitions found in 40 CFR 51.301. There are, of course, numerous articles and explanations for the deciview metric. One article may be found in the publication "IMPROVE," Volume 2, No. 1, April 1993 which was written by Pitchford and Malm, 1993. From a non-mathematical point of view, the change in deciview of "1" is intended to represent a "just noticeable change" (or sometimes referred to as 'just discernible') in visibility regardless of the baseline visibility.

4.0 REASONABLE PROGRESS PERSPECTIVE

The first few sections of this report have provided a summary of the overall regional haze program and the nature of Round 2 of implementation. It also outlined the program's basic elements and background. This section of the report describes the efforts already taken to reduce emissions nationally and in Montana. The contribution of organic carbon from forest fires to visibility impacts is also examined. This review and discussion lead one to conclude that enough reductions have or are about to be achieved which, by themselves, constitutes (more than) reasonable progress within the meaning of the RHR [7].

4.1 National Emissions

A national downward trend of industrial emissions of SO_2 and NO_x has been evidenced for many years. *Figure 3* depicts the nation-wide emission rate of these two compounds from 1990 through 2017.

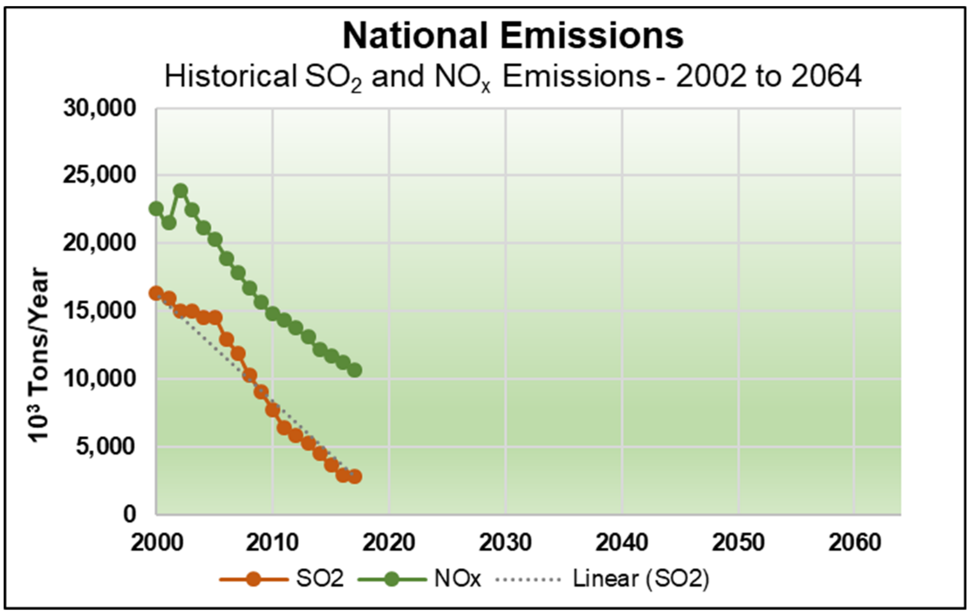

Figure 3: National Emission Trends of SO_2 and NO_x

The reductions observed over these years have occurred for many reasons mostly relating to requirements in the Federal Clean Air Act, the Montana Clean Air Act and industrial facility shutdowns.

From a national perspective, it appears that emissions of SO_2 and NO_x are on a fast-downward trend. While emissions will not likely achieve "zero" by 2064, substantial reductions have and will likely continue to occur. Regardless of the decisions to be reached for Round 2, national emissions contributing to regional haze are anticipated to decline with or without any observed change in visibility impairment.

4.2 Montana Emissions

As depicted in *Figure 4*, the Montana trend in lowering industrial emissions follows the same general pattern as the national data. Except for a modest spike in NO_x emissions around year 2000, there has been a marked reduction in both NO_x and SO_2. It can be inferred; Montana has been doing its part to reach the national goal.

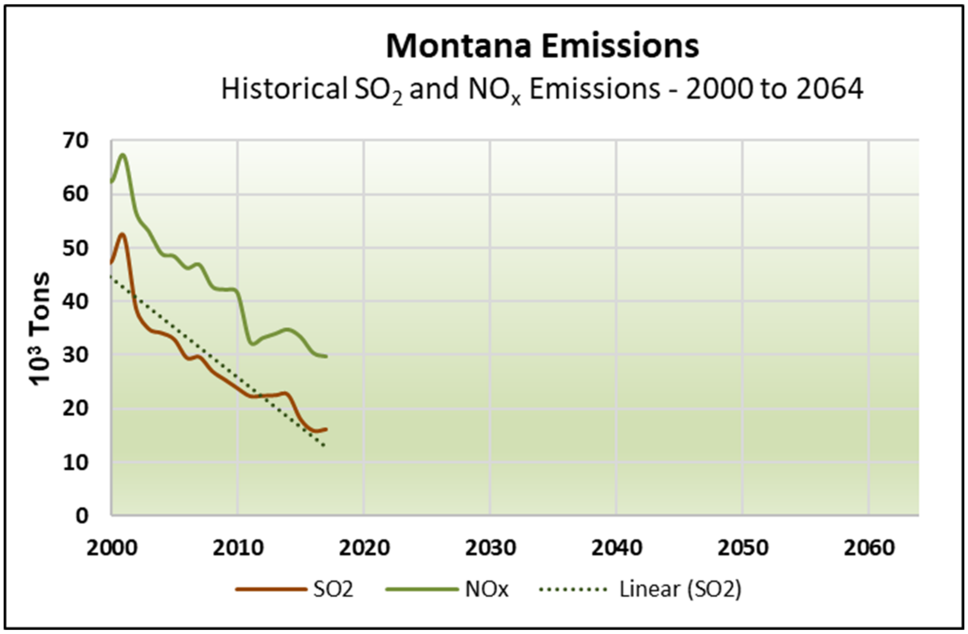

Figure 4: Montana Industrial SO_2 and NO_x Emissions

Regardless of the decisions to be reached for Round 2, industrial emissions within the State of Montana contributing to regional haze are anticipated to decline with or without any observed visibility impairment.

4.3 F.H. Stoltze Emissions and Perspective

As this request for information arises from the RHR it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements. The RHR program (under MDEQ and EPA) has not previously considered Stoltze's emissions as appropriate candidates for additional control under the reasonable progress (or any other) criteria.

Current emissions from the Stoltze boiler are low and are not expected to increase during the foreseeable future. MDEQ has requested identification of the current baseline emissions and the projected future emissions from the Stoltze boiler. Based on the regulations and information reviewed, Stoltze has reported to MDEQ that the current baseline (2017-2018) emissions of 7.11 tpy SO_2 and 73.92 tpy NO_x are a reasonable estimate for the 2028 emissions (*Appendix A*).

The Stoltze boiler project was constructed as a replacement for older boilers in 2013. The new Wellons boiler generates electricity from biomass as well as steam for process purposes. The project is included in the State of Montana Regional Haze 5-year Progress Report as a new source of renewable energy [4]. Reported NO_x and SO_2 emissions from the boiler are proportional to steam production and are consistent from year to year. *Table 1* shows the annual actual SO_2 and NO_x emissions that Stoltze reported to MDEQ.

Table 1: F.H. Stoltze Reported Annual Emissions

Reporting Year	SO_2 Emissions (tpy)	NO_x Emissions (tpy)
2014	5.6	58.1
2015	6.9	71.6
2016	6.8	70.4
2017	7.2	74.3
2018	7.1	73.5

shows that the Stoltze emissions are stable and have not varied significantly since the new boiler was installed in 2013. Montana emission inventory data ( ) clearly shows substantial and adequate reductions in SO_2 and NO_x emissions in the period since 2000 from other industrial sources in Montana. These reductions have resulted from voluntary source actions, implementation plans, plant closures, new plant constructions, and numerous consent decrees.

4.4 Emissions vs Visibility Impairment Analysis

The next step in the reasonable progress perspective is to analyze the current and historical visibility measurements against emissions. A review of anthropogenic sources, and to what extent, these sources actually impact the Class I area of interest was completed to determine the anthropogenic impact on visibility. There are several methods one may employ to determine if any emission reduction would lead to an improvement in visibility at a ‘nearby’ Class I areas. This analysis reviews the information in retrospect, and also discusses how that data informs predictions of future visibility impacts.

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from emissions reductions from the Stoltze boiler.

In addition to emissions data, there is concurrent visibility data at all the ‘nearby’ Class I areas. These areas and their closest proximity to Stoltze are shown in *Table 2*. Glacier National Park is much closer to Stoltze than any other area so the following analyses will focus on that Class I area.

Table 2: Nearby Class I Areas and Proximity

Nearby Class I Area	Approximate Distance from Stoltze (*kilometers*)
Glacier National Park	14
Bob Marshall Wilderness Area	84
Mission Mountain Wilderness Area	89

It is, therefore, possible to glean some insight as to whether the visibility data is responding to changes in emissions during the same time period. If Stoltze has a measurable impact on visual impairment at a Class I area, then the observed visibility (using deciviews as the indicator) would follow the trend. Due to a myriad of statistical confounding variables, meteorology among them, it would not be expected that this correlation between emissions and visibility (deciviews) to be necessarily linear or strong. Nonetheless, if Stoltze emissions have not changed substantially during the monitoring period (2000 to present), it is logical to assume that the deciview parameter at the Glacier National Park IMPROVE monitor would not have changed.

4.5 Potential Impact on Reasonable Progress

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from Stoltze itself or combined with other nearby sources. This analysis relies on actual visibility data collected at Glacier National Park, which is the closest Class I area. Visibility data for the park was taken from the Western Regional Air Partnership (WRAP)[8] and generated from the IMPROVE monitoring network. [1,2,9]

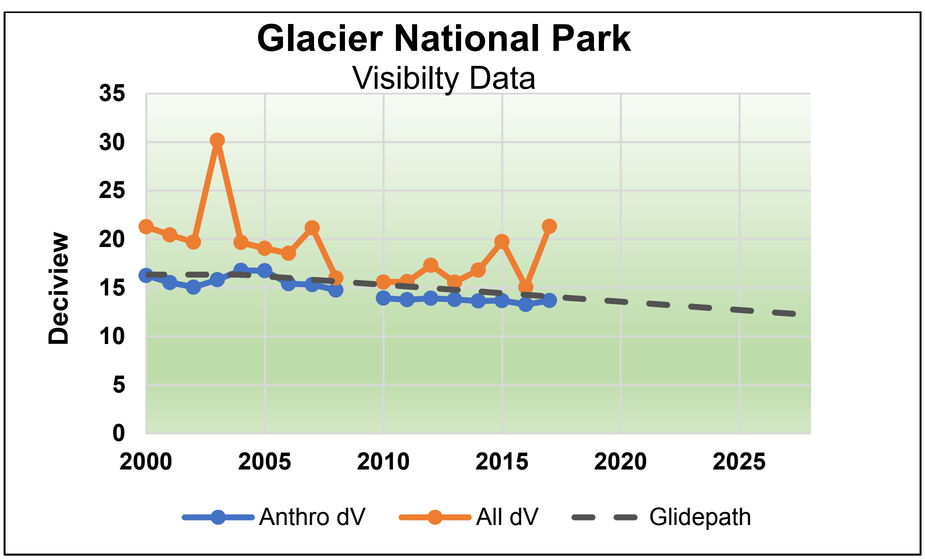

Figure 5: Glacier National Park Visibility Glidepath through 2028

The analysis starts by a graphical review of the emissions and visibility data over time. Figure 5 compares visibility (Anthro dV refers to anthropogenic deciview impairment) and the RHR glidepath at Glacier National Park. The glidepath refers to the line of projected improvements from the starting point of the RHR in 2000-2004 to "natural background" in 2064. Each Class I area has its own glidepath, specific to its visibility degradation baseline.

As shown in Figure 5, the anthropogenic visibility impacts, labeled Anthro dV, have decreased steadily along the glidepath for Glacier National Park. The total visibility impacts, labeled All dV, include natural impacts as well as anthropogenic impacts. The total visibility impacts show a general downward trend, with significant spikes in some years. These spikes represent years with severe smoke intrusion during the fire season. In the summer of 2003, for example, large fires burned within Glacier National Park.

The Montana FIP described visibility conditions at each Class I Area in Montana for the baseline years of 2000-2004 and established a long-term strategy, to be implemented over the ten-year period ending in 2018, toward the ultimate goal of achieving natural visibility conditions. The Montana FIP also included visibility progress goals that each Class I Area was expected to achieve by 2018, referred to as Reasonable Progress Goals (RPGs). The RPGs are interim visibility improvement benchmarks on a path toward the long-term goal of natural conditions.

Data in the Montana progress report shows the current visibility conditions compared to the 2000-2004 baseline conditions and the RPG values for each site. The Glacier National Park IMPROVE site showed that the current visibility conditions are already at 79% of the RPG for both the best and the worst days [4]. The Glacier National Park site is meeting the reasonable progress goals with no reduction in emissions from the Stoltze boiler.

5.0 FOUR-FACTOR ANALYSIS

Per the email from MDEQ dated March 13, 2019, a four-factor analysis was completed for Stoltze (Appendix A). This facility was selected by the MDEQ because of a “Q/d” analysis, used by MDEQ to screen facilities for Round 2. MDEQ’s Q/d analysis used 4.0 as their action threshold for analysis. The Stoltze boiler had a Q/d of 5.4 based on the distance to Glacier National Park and the 2014-2017 average emissions. The Q/d value would be 5.8, based on the distance to Glacier National Park and the 2017-2018 baseline emissions.

The following outlines the analysis for this source using primarily the direction of the EPA Draft Guidance [10] and the WRAP 2009 four-factor analysis [11]. The initial step in the four-factor analysis was to identify possible additional control options for this source. The options chosen include control techniques addressed in guidelines published by the EPA, the EPA Cost Control Manual, BART analyses, and National Association of Clean Air Agencies (NACAA).

5.1 Available SO_2 Control Technologies

SO_2 is formed during combustion due to the oxidation of sulfur in the fuel. Woody biomass fuel has naturally low sulfur contents and SO_2 emission controls are not used. Any add-on control for SO_2 control would be cost-prohibitive due to the small amount of pollutant controlled. This conclusion is consistent with the Best Available Control Technology (BACT) determination made for the Wellons boiler when it was permitted as a replacement for the older boilers [12].

5.2 Available NO_x Control Technologies

NO_x is formed during the combustion of woody biomass fuel in the Wellons boiler. NO_x comes from two sources in combustion, fuel NOx and thermal NO_x. Fuel NO_x forms due to oxidation of nitrogen contained in the biomass fuel and is a small contributor to the total NO_x emissions. Most of the NO_x emissions are thermal NO_x which forms from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. NO_x emissions from a boiler can be controlled using combustion modifications that reduce thermal NO_x formation, or by add-on control devices to remove NO_x from the exhaust stream after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NO_x.

The Wellons boiler was subject to a BACT analysis during the permit application process when it was permitted in 2012. The BACT analysis included consideration of combustion controls and add-on NO_x emissions controls. Staged combustion, flue gas recirculation, and over-fire air all describe NO_x combustion techniques that reduce the formation of NO_x emissions in the boiler. The Stoltze Wellons boiler is equipped with staged combustion flue gas recirculation and over-fire air. These NO_x control technologies are required by the Montana air quality permit for the facility [12].

Additional control could be achieved by add-on emissions control technology as discussed below. The efficiency of the add-on controls would be reduced because of the low NO_x concentration emitted from the boiler. Because the Wellons boiler is already equipped with combustion controls, this cost-effectiveness analysis only considers add-on controls including:

- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR)

5.2.1 Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO_2) to molecular nitrogen, water, and oxygen. Ammonia (NH_3) or urea is used as the reducing agent and is injected into the flue gas upstream of a catalyst bed. Urea is converted to ammonia before injection. NO_x and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate which subsequently decomposes to elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors that impact the effectiveness of SCR include inlet NO_x concentrations, catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning [13].

SCR control technology works best for flue gas temperatures between 575°F and 750°F. SCR is typically installed upstream of the particulate control equipment where the temperature is high enough to support the process. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation. At this point in the exhaust system, the flue gas temperature is lower than required for the SCR to operate effectively. Source tests of the Stoltze Wellons boiler stack show an average stack exit temperature of 285°F.

The Wellons boiler underwent BACT analysis when it was permitted in 2012. At that time, Wellons stated they had never installed an SCR on a wood-fired boiler this small, and Wellons was not confident that the system could operate effectively as they have no operating experience. Stoltze considers this alternative technically infeasible and SCR is eliminated from any further consideration as a feasible control technology.

5.2.2 Selective Non-catalytic Reduction

SNCR uses the noncatalytic decomposition of NO_x in the combustion gases to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The SNCR reaction can take place upstream of the particulate control equipment, so supplemental fuel is not required. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result [14].

Removal efficiencies of NO_x vary for SNCR, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount, and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and the presence of interfering chemical substances in the gas stream. The estimated control efficiency for SNCR is 30%-50%. Because the Stoltze Wellons boiler is equipped with NO_x reduction technology, the lower end of the efficiency range, 30%, is assumed.

5.2.3 Summary of NO_x Control Technologies

The Stoltze Wellons boiler is currently equipped with combustion controls to minimize the formation of NO_x emissions. The permit limit for NO_x emissions is 0.26 pounds per million Btu (lb/MMBtu), which is equivalent to 18.2 pounds per hour (lb/hr) [12]. The analysis has identified SNCR as the only feasible add-on NO_x control technology that could potentially be applied to the Wellons boiler.

The highest level of control that can be realized is accomplished by utilizing SNCR. The four-factor analysis examines the environmental, energy and economic impacts of an SNCR installation on the Stoltze Wellons boiler. SNCR could potentially provide an emissions reduction of 30% when used in conjunction with the existing NO_x controls. Based on this assumption, the NO_x emission rate could be reduced to 0.18 lb/MMBtu and 12.7 lb/hr.

5.3 Factor 1: Cost of Compliance

The cost of compliance analysis was based on a spreadsheet developed by EPA to implement the June 2019 update of the SNCR chapter of the EPA Control Cost Manual [15]. A printout of the completed spreadsheet, titled Air Pollution Control Cost Estimation Spreadsheet for SNCR, is included in *Appendix B* along with supporting information used in the analysis.

The SNCR cost estimate spreadsheet is designed for use with coal-fired and oil- and natural gas-fired boilers. Bison has modified the spreadsheet for use with the Stoltze boiler by substitution wood fuel characteristics for coal characteristics. The fuel information for the wood/bark fuel is based on fuel analysis for samples collected during the most recent source test on the Wellons boiler (*Appendix B*).

5.3.1 SNCR Data Inputs

The combustion unit is an existing industrial boiler – the addition of SNCR would be a retrofit installation. A retrofit factor of 1 was used to indicate that it would be expected to be a project of average retrofit difficulty. The fuel type box is blank because no default information was used. The higher heating value (HHV), sulfur content and ash content of the wood fuel was obtained from the sample data (*Appendix B*).

The net plant heat input rate (NPHR) was calculated in units of million Btu per megawatt (MMBtu/MW) for input into the spreadsheet as described below. The NPHR value for the Stoltze boiler is lower than typical electric power boilers because only a portion of the heat input is converted to electricity while the rest is used as steam for the dry kilns.

The Stoltze sawmill cuts green lumber which is dried in lumber kilns. Steam to heat the for the kilns is supplied by the Wellons boiler which has a nominal rated capacity of 40,000 lb/hr and heat input up to 70 MMBtu/hr. Steam from the boiler is used to run a generator which produces 2.5 megawatts (MW) of power.

The steam heat output is converted to MW using the heat content of saturated steam (1,1191 Btu/lb steam) and the following conversion:

- 40,000 lb steam/hr * 1,191 Btu/lb steam * 1 MMBtu/(1E6 Btu) = 47.64 MMBtu/hr heat output
- 47.64 MMBtu/hr ÷ 3.412 MW/MMBtu/hr = 13.96 MW
- Additional 2.5 MW Electrical Power
- NPHR = 70 MMBtu ÷ (13.96MW + 2.5MW) = 4.25 MMBtu/MW

The maximum potential inlet NO_x emissions to the SNCR are 0.26 lb/MMBtu as limited by the air quality permit. A removal efficiency of 30% is assumed, and the outlet NO_x emissions from the SNCR would be 0.182 lb/MMBtu.

The estimated Normalized Stoichiometric Ratio (NSR) was obtained from the EPA Control Cost Manual for SNCR [14]. Figure 1.8 of the control cost manual chapter on SNCR shows the lowest NO_x emission rate for which SNCR control would be applied is 0.40 lb/MMBtu. The corresponding NSR of 1.15 for 0.40 lb/MMBtu and 30% removal efficiency was used in the spreadsheet.

For this application, it was assumed that the SNCR would use urea, and the reagent values for urea in the spreadsheet are the default values. The cost values are based on the 2018 Chemical Engineering Plant Cost Index (CEPCI) value of 603.1, based on the annual average. The spreadsheet default annual interest rate of 5.5% was used. The fuel cost for the hog fuel was estimated to be $2.05/MMBtu based on an assumed cost for handling the fuel of $20 per ton and a fuel high heating value (HHV) of 9.76 MMBtu/ton. Ash disposal cost was not included because the spreadsheet excludes ash removal costs for non-coal fuels. The spreadsheet default costs for reagent, water and electricity were used in the analysis.

5.3.2 Cost Effectiveness Calculation Results

The cost calculation results showed that the addition of SNCR to the Stoltze Wellons boiler would have a cost effectiveness of $8,092 per ton of NO_x removed, in 2018 dollars. This value represents the cost of installing and operating SNCR add-on NO_x control technology to the Wellons boiler, which is already equipped with combustion controls to reduce the formation of NO_x.

5.4 Factor 2: Time Necessary for Compliance

For SNCR, EPA states in its Cost Control Manual, "Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions."[14] EPA also states in its 2008 Electric Generating Unit (EGU) NO_x Mitigation Strategies Proposed Rule Technical Support Document (TSD) for the Cross State Air Pollution Rule for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) [16], that "SNCR … requires 12 months from contract award through commissioning." In addition, SNCR would require additional time for "conceptual design, permitting, financing, and bid review." Given that, Stoltze is estimating SNCR would require approximately 24 months for design, permitting, financing, etc. through commissioning.

5.5 Factor 3: Energy and Environmental Impacts of Compliance

SNCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

An SNCR system would have a very small energy penalty on the overall operation cost of the boiler. Costs for this energy expenditure are included in the discussion of Factor 1, cost of compliance.

5.6 Factor 4: Remaining Useful Life

The Stoltze Wellons boiler was manufactured in 2012 and installed at the Columbia Falls facility in 2013. For this four-factor analysis, it has been assumed that the boiler has a remaining useful life of 20 years based on MDEQ guidance which stated that a 20-year planning horizon should be assumed for the purpose of the requested reasonable progress analysis. The only exception to his horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired.

6.0 CONCLUSIONS

A four-factor analysis has been conducted for the Stoltze biomass-fired boiler. The analysis was conducted to meet the requirements of Round 2 to develop of a SIP to address Regional haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, MDEQ requested this analysis from Stoltze.

The four factors analyzed were based on the MDEQ correspondence and the RHR to determine if there are emission control options at Stoltze that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and the remaining useful life of the existing source subject to these requirements.

The four-factor analysis was conducted for NO_x on the Wellons boiler at the Stoltze sawmill facility. The boiler was installed in 2013 to replace older steam equipment and to add capability of generating electricity from biomass combustion.

With respect to the purpose of this analysis, the RHR [§308(d)] outlines what it refers to as: "the core requirements" for the implementation of the regional haze goals. More specifically, §308(d)(1) states:

> "*For each mandatory Class I Federal area..., the State must establish goals... that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days..."* [40 CFR 51.308(d)(1)].

Reasonable progress is tied to an improvement in visibility, not costly pollution control without benefit. The results of the analysis have indicated that additional NO_x controls the Stoltze boiler are not necessary to make reasonable progress due to costs and Stoltze's lack of a measurable impact on any nearby Class I area. It is concluded that this facility does not qualify for additional emission controls or limitations based on this analysis.

7.0 REFERENCES

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APPENDIX A: COMMUNICATIONS WITH MDEQ

Air, Energy & Mining Division

March 15, 2019

Sent electronically via email to: trevorkjensrud@stoltzelumber.com

Trevor Kjensrud
F.H. Stoltze Land & Lumber Co.
600 Halfmoon Road
Columbia Falls MT 59912

RE: Regional Haze Source Screening Analysis

Dear Mr. Kjensrud:

The Montana Department of Environmental Quality, Air Quality Bureau (AQB), is working on a State Implementation Plan (SIP) for the second planning period of the Regional Haze program, which is codified at 42 U.S. Code §7491 – *Visibility protection for Federal class I areas.* This planning period focuses on making reasonable progress toward national visibility goals.

The AQB has completed an initial Regional Haze screening analysis of the F.H. Stoltze Land and Lumber Co. (Stoltze) facility and determined that the facility may need further review of process controls specifically related to nitrogen oxides (NO_x).

Monitoring data indicate that sulfates and nitrates are the main contributors to anthropogenic haze in Montana. The primary precursors of nitrates and sulfates are emissions of NO_x and SO_2. The AQB based its initial analysis on the annual emission inventories submitted by Stoltze to the AQB for the years 2014-2017, which are compiled in Table 1 below. The initial screening analysis also considers the distance from the facilities to the boundary of the nearest Federal class I areas (Glacier National Park). Taken together, emissions and distance provide a screening tool to identify facilities that may be contributing to haze and that therefore may require further analysis.

Table 1 – Facility-Wide NO_x and SO_2 Emissions and Screening Analysis

NO_x 2014-2017 Average (TPY)	SO_2 2014-2017 Average (TPY)	Nearest Class I Area	Distance to Class I Area	2014-2017 Q/d ($Q=NO_x+SO_2$)
68.62	6.60	Glacier National Park	14km	5.37

Table 2 – 2017 unit-level NOx emissions and process rate

Unit	Process Rate	NOx
Wellens Boiler	571082 MMBtu	74.27 tons

Table 3 – Existing Process Controls

Unit	NO_x Control	% Removal Est.
Wellens Boiler	stated combustion and flue gas recirculation	

At this time, the AQB requests your review of the emissions and control equipment information the AQB has on file for the facility. Following this initial review, the AQB may be asking that you prepare a detailed review of additional process controls, specifically considering (1) the cost of control, (2) the time required to achieve control, (3) the energy and non-air quality environmental impacts of control, and (4) the remaining useful life of the source of emissions. The AQB will be contacting you shortly to schedule a call to discuss the initial screening analysis in more detail.

If you have any questions or concerns, please contact me by phone at (406) 444-5287 or by e-mail at repayne@mt.gov

Sincerely,

Rhonda Payne
Air Quality Bureau

Cc: Karen Wilson, AQB

Diane Lorenzen

From: Debbie Skibicki
Sent: Thursday, May 30, 2019 8:48 AM
To: Trevor Kjensrud
Cc: Diane Lorenzen; Chris Hiltunen
Subject: RE: Regional Haze Baseline Emissions Request

Hi Trevor,

As DEQ mentioned, baseline emissions are where I'd recommend going first. We need a solid basis for the four-factor analysis, so if you have a more representative year in 2014-2017, or if an average makes the most sense, I'd recommend building that justification. That's in our proposal too and part of the process.

For example, one of our clients had a major, unexpected shutdown for most of 2017, so we're reviewing the other years in DEQ's timeframe to determine what makes the most sense for their baseline. That facility baseline will also be used to look at where the facility may be in 2028 (the end of the regional haze planning period), so it needs to be one that makes sense from an operations standpoint.

I'm out of the office tomorrow, but am around today. We can chat today or next week if you have questions.

Debbie

From: Trevor Kjensrud <trevorkjensrud@stoltzelumber.com>
Sent: Thursday, May 30, 2019 6:32 AM
To: Debbie Skibicki <dskibicki@bison-eng.com>
Subject: FW: Regional Haze Baseline Emissions Request

Debbie,

Good morning,

We received this from DEQ about the Regional Haze; looking for some guidance. I have a managers meeting this morning and plan on discussing your help with this issue (the quote you had sent). Could you let me know what I/We should be doing next?

Respectfully,

Trevor Kjensrud
Plant Manager
FH Stoltze Land and Lumber Company

From: Payne, Rhonda <repayne@mt.gov>
Sent: Tuesday, May 28, 2019 2:51 PM
To: 'trevorkjensrud@stoltzelumber.com' <trevorkjensrud@stoltzelumber.com>
Subject: RE: Regional Haze Baseline Emissions Request

Hi Trevor,

Sorry, I took the language from the Graymont facility and copied it into your email – I forgot to change the header on the emissions information. Rest assured, the NOx numbers are correct for the F.H. Stoltze facility. Sorry about that!

--Rhonda

Rhonda Payne
Montana DEQ – Air Quality Bureau
Permitting Services Section
Phone: 406.444.5287
Fax: 406.444.1499

From: Payne, Rhonda
Sent: Tuesday, May 28, 2019 2:47 PM
To: trevorkjensrud@stoltzelumber.com
Subject: Regional Haze Baseline Emissions Request

Hello Trevor,

Thank you for the work you have conducted thus far toward submitting the requested Four Factor Analysis. As you are aware, Montana used an average of your facility's 2014-2017 emissions as a screening mechanism to determine if the facility would be required to perform a Four Factor Analysis. We are now seeking your input regarding emission scenarios to be used in regional modeling demonstrations. Over the next six months, DEQ will be working closely with the Western Regional Air Partnership (WRAP) to provide emissions information for several modeling demonstrations. These demonstrations include:

1) A "representative baseline" scenario,
2) A future year "2028 on the books/on the way (2028 OTB/OTW)" scenario, and
3) A future year "2028 controls" scenario.

The "representative baseline" scenario will be based on emissions information that is representative of the current level of emissions from normal operations at the facility today. Representative baseline emissions must be confirmed now so that this modeling demonstration can be conducted in June 2019.

Future year emission scenarios will be built using the "representative baseline" scenario as a starting point. These future year scenarios include the "2028 OTB/OTW" scenario, which will incorporate any changes in emissions between the baseline (now) and 2028 that are expected to result from rules and regulations already adopted or anticipated. Modeling for this scenario will be conducted in August 2019. The second future year emission scenario is the "2028 controls" scenario, which will incorporate reductions that result from any additional controls required as a result of the Four Factor Analysis. This round of modeling will be conducted in December 2019.

The purpose of this email is to confirm the representative baseline emissions for your facility that will be used for the June modeling effort. Having reviewed your recent annual emissions inventories, we are proposing to use an average of 2017-2018 as your representative baseline emissions. We need concurrence that this two-year period generally represents normal conditions at your facility currently. If you feel that the two-year period of 2017-2018 does not represent your baseline emissions, our second proposal is to use an average of 2014-2017, which would be identical to the data used in the Q/d analysis.

Please respond to this email to confirm whether the two-year average (2017-2018) or the four-year average (2014-2017) is more representative of your current baseline emissions (see below). **We request that you confirm this information no later than June 7, 2019.** Later this summer, we will be contacting you to share results from the baseline modeling and confirm future year emissions for the "2028 OTB/OTW" modeling scenario.

Below are the two "representative baseline" options that we propose you select from.

Graymont – Indian Creek Facility
4-year average (2014-2017) = 74.32 tpy NOx

2-year average (2017-2018) = 73.91 tpy NOx

Talk to you soon,

Diane Lorenzen

From: Payne, Rhonda <repayne@mt.gov>
Sent: Thursday, June 06, 2019 11:03 AM
To: Diane Lorenzen
Cc: Debbie Skibicki; trevorkjensrud@stoltzelumber.com
Subject: RE: Regional Haze Baseline Emissions Request for F.H. Stoltze Lumber

Thank you, Diane. I will mark F.H. Stoltze as requesting the 2017-2018 average emissions.

--Rhonda

Rhonda Payne
Montana DEQ – Air Quality Bureau
Permitting Services Section
Phone: 406.444.5287
Fax: 406.444.1499

From: Diane Lorenzen [mailto:DLorenzen@bison-eng.com]
Sent: Thursday, June 06, 2019 8:54 AM
To: Payne, Rhonda <repayne@mt.gov>
Cc: Debbie Skibicki <dskibicki@bison-eng.com>; trevorkjensrud@stoltzelumber.com
Subject: Regional Haze Baseline Emissions Request for F.H. Stoltze Lumber

Rhonda,

Bison is providing this response on behalf of F.H. Stoltze regarding regional haze baseline emissions. DEQ has requested feed back on establishment of “representative baseline” emissions for the Stoltze boiler. DEQ proposed to use an average of 2017-2018 reported actual NOx and SO2 emissions as the representative baseline emissions for the Stoltze boiler. Bison and Stoltze concur that this two-year period generally represents normal operational conditions for the Stoltze boiler. The following is a summary of the data.

2017 NOX was 74.32 tpy and SO2 was 7.15 tpy - the total was 81.47 tpy.
2018 NOX was 73.51 tpy and SO2 was 7.07 tpy - the total was 80.58 tpy.
Average NOx was 73.92 tpy and average SO2 was 7.11 tpy. The average total was 81.03 tpy

Thank you for including the affected facilities at each step of this process.

Diane

Diane R. Lorenzen, P.E.

BISON ENGINEERING, INC.
1400 11th Avenue ● Helena, MT 59601 ● 406-442-5768
Fax: 406-449-6653 ● E-MAIL: bison@bison-eng.com ● www.bison-eng.com

July 29, 2019

Craig Henrikson, P.E.
Air Quality Bureau
Montana Department of Environmental Quality
PO Box 200901
Helena, MT 59620-0901
Via email to: chenrikson@deq.mt.gov

RE: F.H. Stoltze – Regional Haze Analysis

Dear Mr. Henrikson,

Bison Engineering, Inc. (Bison) is providing this letter in an information request related to regional haze analysis for F.H. Stoltze. Bison is attempting to provide consistent response materials for all of our clients who are included in this process.

On July 9, 2019 DEQ issued an email request to affected parties to provide an estimate of future visibility impairing emissions (specifically oxides of nitrogen, NOx, and sulfur dioxide, SO_2) for affected facilities. This response provides a response to the question on behalf of the F.H. Stoltze Land and Lumber Company – Columbia Falls Sawmill (Stoltze), located in Columbia Falls, Montana .

The July 9, 2019 email is one of various data requests from the Montana Department of Environmental Quality (MDEQ) which are related to what has been termed the 2nd planning period for implementation of the Regional Haze Rule (RHR) found in 40 CFR 51.308 *et. seq.*

For this request, MDEQ has asked for an estimate of a future year 2028 emissions (again, for NOx and SO_2) described as “on the books” or “on the way.” For convenience this is referred to as the “2028 OTB/OTW” scenario. The following description of the needed data is provided below:

> *“Representing anticipated future emissions and incorporating any changes in emissions between the baseline and 2028 that are expected to result from non-Regional Haze rules and regulations already adopted or anticipated. Depending on your operations, this may or may not be different from your representative baseline emissions.”*
>
> (July 9, 2019 email from Craig Henrikson to Bison client)

The term “baseline emissions” is, in Stoltze’s case, a reference to the actual average annual emission rate for calendar years 2017 through 2018.

This response provides various analyses and discussions to provide an estimate of the 2028 OTB/OTW scenario NOx/SO_2 emission rate. The prediction of future emission rates is a non-specific endeavor. It is not possible to provide a 'guarantee' of a specific rate between now and 2028, only a reasoned estimate based on various presumptions of future requirements and activities.

On the Books

"On the Books" refers to making an estimate of future (current through 2028) emissions as a result of regulations or requirements that are currently (or known to soon be) "on the books." As the phrase implies it is appropriate to consider how emissions might change because of some specific requirement that is or about to be imposed by a regulation. It is noted here that MDEQ only seeks such projects that would or are about to be implemented by some regulatory program other than the RHR and upcoming 4-Factor analysis. Emissions from the RHR and 4-Factor analysis will be addressed at a future time. For this On the Books analysis, only projects that affect emissions are of interest if the project would occur with or without consideration to the RHR.

Stoltze and Bison have reviewed various existing and proposed regulations as they might affect NOx/SO_2 emission rates. Among them were:

Name / Title	Citation
New Source Performance Standards	40 CFR 60
National Emission Standards for Hazardous Air Pollutants	40 CFR 61
National Emission Standards for Hazardous Air Pollutants (MACT)	40 CFR 63
National Ambient Air Quality Standards	40 CFR 50
Accidental Release Prevention	40 CFR 68

In addition to these (and other) federal programs, the same review was considered for Montana rules. Although not listed here, it included a review of the current rules along with a review of current or proposed action by the Montana Board of Environmental Review. The review of this information has indicated that there are no known new regulatory efforts that are known to affect the Stoltze boiler emissions directly.

On the Way

"On the Way" projects refer to efforts which might affect future emissions in a measurable way. This task is in reference to the identification of a specific project which:

- is currently in the formal planning stage,
- has begun construction,
- began operation after the baseline,
- has obtained financing; or
- is otherwise planned and highly likely to be completed by 2028.

As noted earlier, this requirement relates only to those projects that would occur regardless of the status of the 4-Factor analysis.

Stoltze and Bison have reviewed current construction, planned construction and internal planning processes at Stoltze. The team concluded that Stoltze has no project that may be considered “on the way” as referenced to the 2nd planning period. It was also concluded that no increase of capacity or production (with potential resultant emissions) is anticipated.

Conclusion

Based on the regulations and information reviewed, we believe that the current baseline (2017-2018) emissions of 7.11 tpy SO_2 and 73.92 tpy NOx are a reasonable estimate for the “2028 OTB/OTW” modeling scenario. Please contact me with any questions at (406) 531 – 0195 or dlorenzen@bison-eng.com.

Sincerely,
BISON ENGINEERING, INC.

Diane R. Lorenzen

Diane R. Lorenzen, P.E.
Senior Project Engineer

Cc Trevor Kjensrud, F.H. Stoltze, via email
trevorkjensrud@stoltzelumber.com

APPENDIX B: COST ANALYSIS CALCULATIONS

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

(June 2019)

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 methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). 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 version 6). 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 retrofit 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 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, 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 ***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?

Is the SNCR 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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 70 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,880 Btu/lb

What is the estimated actual annual fuel consumption? 125,655,738 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 4.25 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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = 0.02 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 0.064 percent by weight

Not applicable to units buring fuel oil or natural gas

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	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

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	0.26	lb/MMBtu	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.182	lb/MMBtu	
Estimated Normalized Stoichiometric Ratio (NSR)	1.15		
Concentration of reagent as stored (C_{stored})	50	Percent	
Density of reagent as stored (ρ_{stored})	71	lb/ft^3	
Concentration of reagent injected (C_{inj})	10	percent	
Number of days reagent is stored ($t_{storage}$)	14	days	
Estimated equipment life	20	Years	
Select the reagent used	Urea		

Plant Elevation: 3064 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	2.05	$/MMBtu		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 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 value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water 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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.74	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	6,685	Select type of coal	
Interest Rate (%)	5.5	Default bank prime rate	

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 =	70	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	125,655,738	lbs/Year	
Actual Annual fuel consumption (Mactual) =		125,655,738	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.43		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	30	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.46	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	23.91	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)	1.00		Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at 3064 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* 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)	14	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	27	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	2.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0837

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.3	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	13	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 1×10^6)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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 ($SNCR_{cost}$) =	$414,121 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$732,803 in 2018 dollars
Total Capital Investment (TCI) =	$1,491,001 in 2018 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 ($SNCR_{cost}$) =	$414,121 in 2018 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 2018 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 (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 Plant Costs (BOP_{cost}) =	$732,803 in 2018 dollars

F.H. Stoltze SNCR Analysis for
Wood-fired Boiler, based on coal

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$68,060	in 2018 dollars
Indirect Annual Costs (IDAC) =	$125,468	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$193,528	in 2018 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 =	$22,365	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$41,859	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,371	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$478	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,987	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2018 dollars
Direct Annual Cost =		$68,060	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$671	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$124,797	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$125,468	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$193,528	per year in 2018 dollars
NOx Removed =	24	tons/year
Cost Effectiveness =	$8,092	per ton of NOx removed in 2018 dollars

HAZEN Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Lab Control ID: 18F01370
Received: May 25, 2018
Reported: Jun 06, 2018
Purchase Order No.
RMB52418

Customer ID: 03749Z
Account ID: Z02768
Project #: FH5218623

ANALYTICAL REPORT

Adam Bender
Bison Engineering

Client Sample ID **FH Stoltze Run 1**
Lab Sample ID 18F01370-001

Reporting Basis >	**As Rec'd**	**Dry**	**Air Dry**
Proximate (%)			
Moisture	42.15	0.00	4.69
Ash	1.52	2.62	2.50
Volatile			
Fixed C			
Total			
Sulfur	0.015	0.025	0.024
Btu/lb (HHV)	4880	8435	8039
Btu/lb (LHV)	4123	7877	
MMF Btu/lb	4961	8681	
MAF Btu/lb		8662	
Ultimate (%)			
Moisture	42.15	0.00	4.69
Carbon	30.49	52.70	50.23
Hydrogen	3.48	6.02	5.74
Nitrogen	0.11	0.19	0.18
Sulfur	0.015	0.025	0.024
Ash	1.52	2.62	2.50
Oxygen*	22.24	38.44	36.64
Total	100.00	100.00	100.00
Chlorine**			

Air Dry Loss (%) 39.3

Forms of Sulfur, as S, (%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.015	0.025

Lb. Alkali Oxide/MM Btu =	
Lb. Ash/MM Btu=	3.11
Lb. SO2/MM Btu=	0.060
Lb. Cl/MM Btu=	
F-Factor(dry),DSCF/MM Btu=	10,065

Water Soluble Alkalies (%)

Na2O
K2O

Report Prepared By:

Mark A. Pugh
Fuel Laboratory Manager

* Oxygen by difference
** Not usually reported as part of the ultimate analysis.

CHEMICAL ENGINEERING PLANT COST INDEX: 2018 ANNUAL VALUE

By Scott Jenkins | March 20, 2019

120

Each month, *Chemical Engineering* publishes the latest values for the *Chemical Engineering* Plant Cost Index (CEPCI) — a widely used resource for plant construction costs. The CEPCI is calculated using various data from the U.S. Bureau of Labor Statistics. Once a year, we calculate and publish an annual average value, which for 2017 was 567.5.

Based on an average of the monthly values for the *Chemical Engineering* Plant Cost Index (CEPCI), the annual average value for 2018 is **603.1**. The total represents a 6.3% rise over the annual value from the previous year. The percentage gain from 2017 to 2018 is greater than the increase from 2016 to 2017, which was 4.8%. Previous average annual values for the CEPCI are as follows: 567.5 (2017); 541.7 (2016); and 556.8 (2015). In addition to the overall CEPCI annual average for 2018, we also calculated the annual 2018 averages for each of the subindexes that make up the CEPCI (Equipment, Construction Labor, Buildings and Engineering & Supervision). Those individual subindex values can be found on the CEPCI website.

Moving ahead to 2019, the first preliminary value for the year (January 2019; the most recent available) also shows an increase over the final December 2018 value of the CEPCI. In January, gains in the Equipment, Engineering & Supervision, and Buildings subindexes offset a decrease in the Construction Labor subindex. The overall CEPCI preliminary value for January 2019 stands at 7.4% higher than the corresponding value from January 2018.

Meanwhile, the Current Business Indicators (CBI) numbers for the chemical process industries (CPI) show a small decrease in the CPI output index for February 2019, as well as a small decrease in the CPI operating rate. Producer prices for industrial chemicals rose in February 2019. These data can be found in the April issue of *Chemical Engineering* magazine.

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