Regional Haze
Four-Factor Analysis

Yellowstone Energy Limited Partnership
Yellowstone Power Plant

2215 North Frontage Road
Billings, Montana

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Prepared by:
Bison Engineering, Inc.
1400 11th Avenue
Helena, MT 59601

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by the Yellowstone Energy Limited Partnership (YELP) to prepare a four-factor analysis for the Circulating Fluidized Bed Combustion (CFBC) Boilers located at the Yellowstone Power Plant in Billings, MT. The YELP facility is operated by Billings Generation, Inc. (BGI). The facility may be referenced by either name throughout this report. The four-factor analysis was requested by the Montana Department of Environmental Quality (MDEQ) in an email (and follow up discussions) between YELP owners and staff and Craig Henrikson (MDEQ) that began on March 14, 2019.

The analysis itself relates to the second planning period (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 YELP that, if implemented, could be used to attain reasonable progress toward the state's visibility goals.

The four-factor analysis was conducted for oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) on the CFBC Boiler at YELP. The results of the analysis have indicated that additional controls on the CFBC Boiler is not necessary to make reasonable progress due to costs and YELP's lack of a measurable impact on any nearby Class I area. It is also 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

Anthro dV	Anthropogenic deciview
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Bison	Bison Engineering, Inc
BGI	Billings Generation, Inc.
$CaCO_3$	Limestone
CaO	Lime
$CaSO_3$	Calcium Sulfite
$CaSO_4$	Calcium Sulfate
CDS	Circulating Dry Scrubber
CFBC	Circulating Fluidized Bed Combustion
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
HAR	Hydrated Ash Reinjection
ID	Induced draught
Lbs/hr	Pounds per hour
Lb/MMBtu	Pounds per Million British Thermal Units
LEA	Low Excess Air
LNB	Low NO_x Burners
MDEQ	Montana Department of Environmental Quality
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
NO_3	Nitrate
NO_x	Oxides of Nitrogen
O_2	Oxygen
O&M	Operations and Maintenance
OAQPS	Office of Air Quality Planning and Standards
OFA	Overfire Air
PC	Pulverized Coal
ppm_v	parts per million by volume
r	Pearson Correlation Coefficient
r^2	the square of the correlation coefficient r
RBLC	EPA's RACT/BACT/LAER Clearinghouse
RFG	Refinery Fuel Gas
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

SCR	Selective Catalytic Reduction
SDA	Spray Dry Absorber
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TSD	2008 EGU NO_x Mitigation Strategies Proposed Rule Technical Support Document
WRAP	Western Regional Air Partnership
YELP	Yellowstone Energy Limited Partnership

2.0 INTRODUCTION

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 primarily in 40 CFR 51.308.[1] 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.[2] Additional controls for YELP were considered by EPA during that first round, but no additional controls were determined to be appropriate given the small size of the facility, the cost of compliance, and minimal impacts to visibility based on overall facility emissions and distance to Class I areas. Therefore, the FIP, did not propose nor promulgate any additional controls for this facility.

A second round of obligations is now under development, with MDEQ moving into the role as the lead agency. This second round, 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

To implement the four-factor requirement, Craig Henrikson of MDEQ contacted YELP in March of 2019. MDEQ noted this same analysis is required for other sources in the Billings area as well. MDEQ followed up with an April 19, 2019 letter to further clarify various aspects of the requested analysis along with providing EPA guidelines on the matter. In a May 23, 2019 email, MDEQ requested a "representative baseline" emissions period on which to base regional modeling as a part of the Round 2 efforts. YELP chose the 2014-2017 annual emission year period as that representative baseline. Those 2014-2017 annual emissions years are also used as a basis for this four-factor analysis.

[1] The entire visibility program is found in 40 CFR 51.300 to 309.
[2] The FIP was promulgated on Sept. 18, 2012 at 77 FR 57864.

2.1 Facility Information

The primary operation of the YELP facility is the production of steam, a portion of which is transferred to the ExxonMobil Refinery and the remainder utilized to generate electricity via a steam turbine. The YELP facility also provides pollution control capability by processing ExxonMobil Refinery coker gas through its boilers, thus removing sulfur dioxide (SO_2). The facility employs two Circulating Fluidized Bed Combustion (CFBC) boilers in the production of steam, fired by petroleum coke and coker gas as primary fuels. The CFBC boilers vent to the same fabric filter baghouse and the same stack so may also be referred to as the CFBC Boiler (singular). The total design capacity of the facility is 660,000 pounds per hour (lbs/hr) of steam and 65-Megawatts of electrical generation.

YELP encompasses approximately 24 acres and is located at 2215 N. Frontage Road, Billings, Montana. The legal description of the site location is NE¼ of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana. The site elevation is 3,150 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 North Absaroka Wilderness Area, which is the nearest Class I area to YELP. *Figure 2* is a printout of a Google Earth satellite photo of the area surrounding the facility, with the site location indicated.

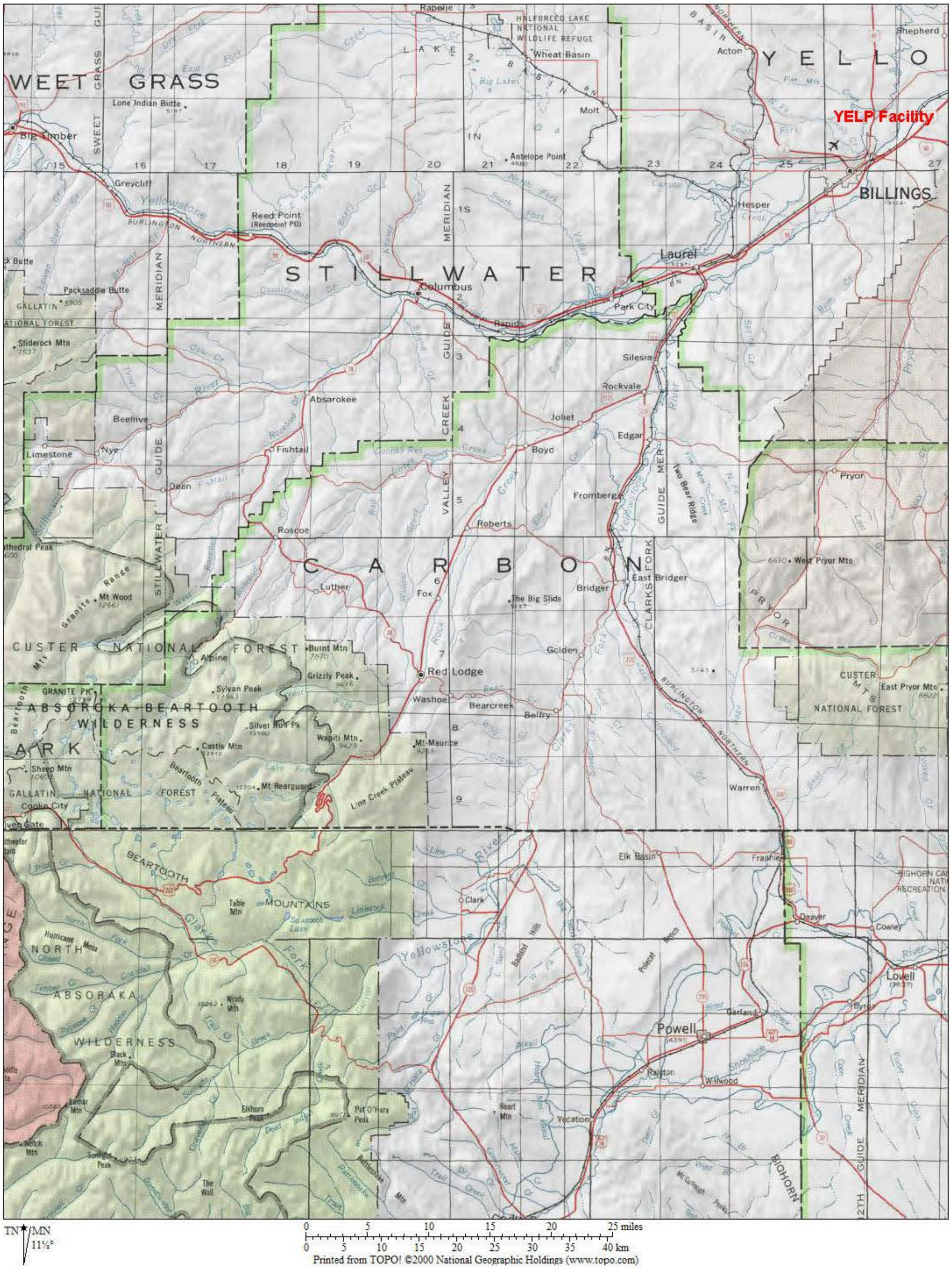

Figure 1: Topographic Map of YELP in relation to nearest Class I area

Figure 2: Google Earth representation of YELP facility

3.0 REGIONAL HAZE 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.[4] 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.[5] YELP was reviewed with respect to the four-factor analysis under Round 1, but no additional controls were applied or required at that time.

3.1 Montana Initiatives

For Montana, Round 1 requirements were executed via the EPA. This planning period roughly included 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.[6] Following much discussion and analyses, EPA six years later promulgated a FIP as it applied to sources in Montana.[7] As previously discussed, the FIP did not impose new or additional controls on YELP 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 analysis 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 various 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

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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.
4 64 FR 35765; July 1, 1999; and 82 FR 3124; Jan. 10, 2017.
5 The BART program is more fully explained in 40 CFR 51.308(e).
6 Letter from DEQ to EPA dated July 19, 2006.
7 The proposed FIP was published April 20, 2012 at 77 FR 23988 and became final on Sept. 18, 2012 at 77 FR 57864.

results of that monitoring have indicated, for eastern Montana and Wyoming Class I areas, that the primary pollutant that accounts for the most anthropogenic (human-caused) regional haze degradation are (ammonium) sulfate and (ammonium) nitrate [2,3].

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 four-factor analysis
Q = mean annual emissions from 2014 to 2017 of SO_2 + NO_x (tons)
d = distance to the nearest mandatory Class I area (kilometers)

A value greater than 4 was calculated for YELP for the given time period (14.86 specifically, based on the 2014-2017 annual emission inventory period) and thus was chosen by MDEQ for a four-factor analysis for Round 2.

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 implementing the 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 (NSR, PSD, etc.) 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 13, 2019 letter and other correspondence to YELP 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-factors analysis that is outlined above in *Section 2.0* and in the March 13, 2019 letter.

3.3 Overall Applicability

Montana is tasked to establish (a plan for) reasonable progress in carrying out the visibility protection. *Section 3.2* 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 [4]. That sentiment is confirmed in Section II.A EPA August 20, 2019 guidance [5]:

> *"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 reduction as a direct result of the application of the control (i.e., a discernible improvement in deciviews[8] in a Class I area).

To that end, YELP has elected to not only analyze various control "options" utilizing four-factors, but has also included a qualitative analysis of impacts this facility may have on several nearby mandatory Class I areas.[9] 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***" per 40 CFR 51.308(d)(1) at a mandatory Class I area [6].

As will be presented in following sections of this document, no measured evidence of any impact by YELP's operations on the visibility in any mandatory Class I airshed was established.

[8] 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.

[9] The nearest Class I area (North Absaroka Wilderness Area) is about 140 kilometers from Billings, Montana.

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 not only from the state, but in the Billings area in particular. 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 [6].

4.1 National Emissions

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

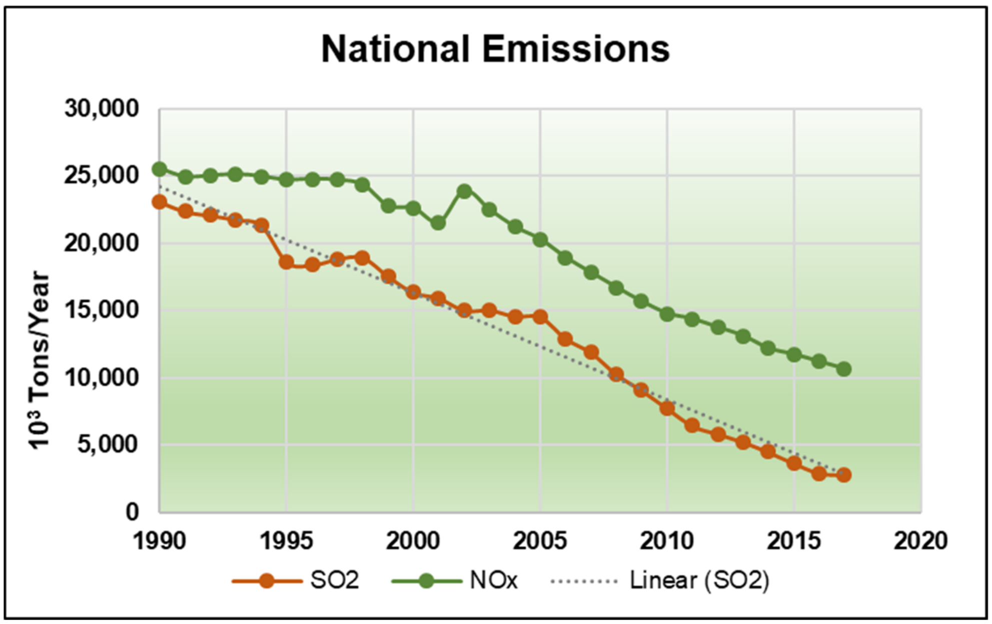

Figure 3: National Emission trends of SO_2 and NO_x

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, individual state regulations, and industrial facility shutdowns.

While *Figure 3* provides a historical perspective, it is also of interest to explore those emissions recorded at the start of the RHR program (2000) as shown in *Figure 4*. This graphic denotes SO_2 emissions through 2064 since that is the year in which the national goal is to be achieved.

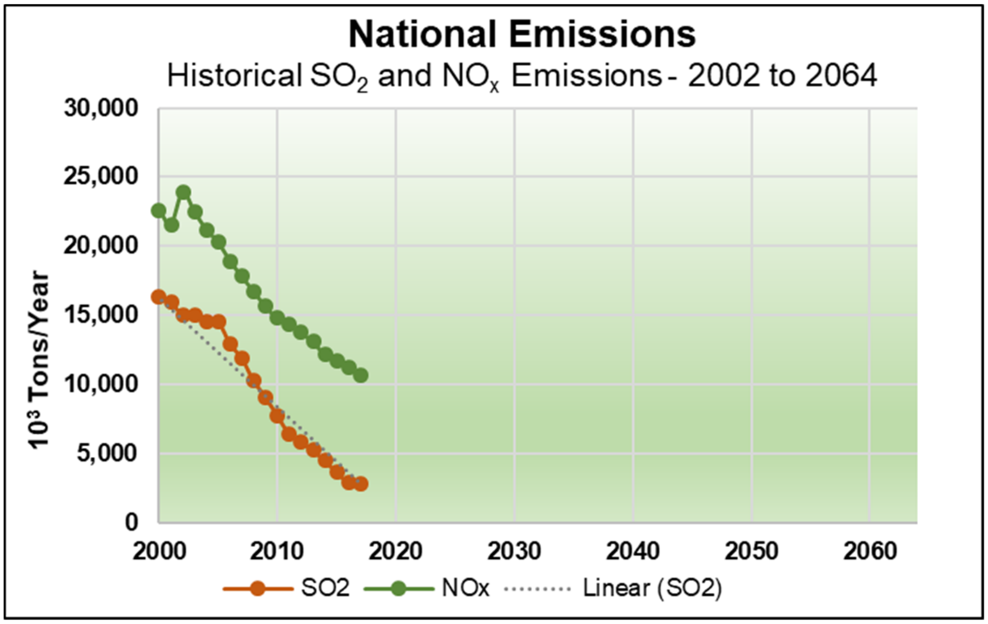

Figure 4: Historical SO_2 and NO_x Emissions

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 visibility impairment.

4.2 Montana Emissions

As depicted in *Figure 5*, 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 that Montana has been doing its part in reducing emissions to achieve the national goal.[10]

[10] This statement presumes (without admission or proof) an *a priori* cause and effect between Montana emissions and observed visibility in any nearby Mandatory Class I area. For reasons that will be forthcoming in the September four-factor analysis, there is, in our opinion, no cause and effect relationship between YELP's NOx and SO_2 emissions in particular and a measurable impact on visibility (expressed in deciviews).

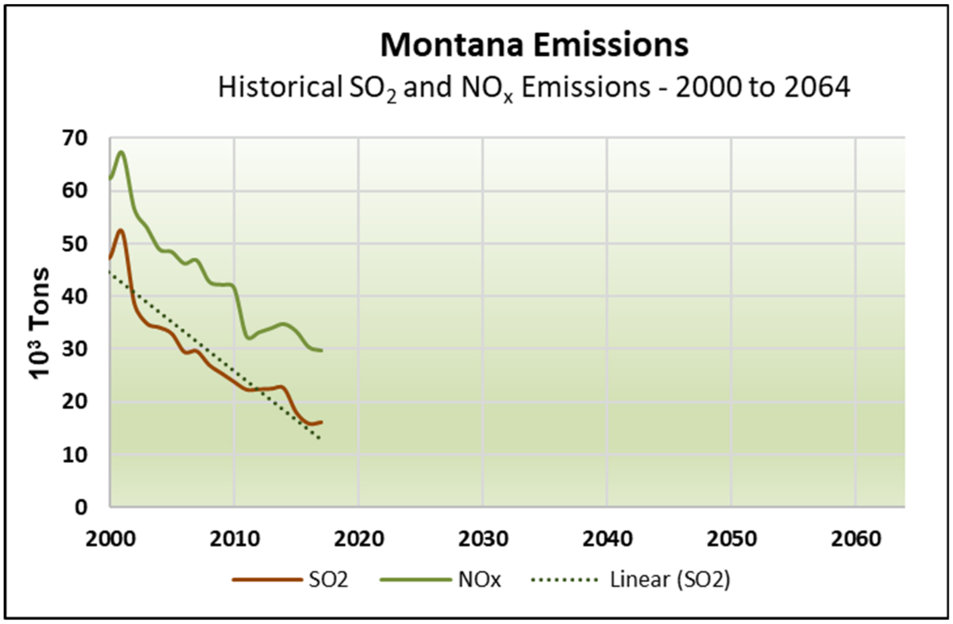

Figure 5: Montana Industrial SO_2 and NO_x emissions

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.[11]

4.3 Billings Area Emissions

Regionally, the Billings area emissions follow a very similar trend as seen in Montana above. The major Billings area industrial sources include YELP, Phillips 66, the CHS Laurel Refinery, the ExxonMobil Billings Refinery, Montana Sulphur and Chemical Company, and Western Sugar. Until its closure in 2015, the Billings area industrial sources also included the J.E. Corette Power Plant, which was one of the largest sources of SO_2 and NO_x emissions in that area averaging 2,774 tons/year of SO_2 and 1,739 tons/year of NO_x between the 2000-2014 annual emission inventory years. Those emissions are no longer in the airshed. Overall, the Billings area has seen a reduction in SO_2 emissions from 25,500 tons/year in 1994 to 4,000 tons/year in 2018, a decrease of roughly 85%. NO_x emissions have also decreased, though not quite as dramatically.

Similar to the national and Montana perspective, *Figure 6* depicts the RHR program through its anticipated ending in 2064 for the major Billings area industrial sources.

[11] It is assumed for this particular discussion alone that a reduction in emissions (SO_2 and/or NOx) has a direct causal relationship with improved visibility. Analyses to follow will show that this is not the case. A reduction in Montana emissions, YELP included, does not translate to an improvement in Class I visibility; linear or otherwise.

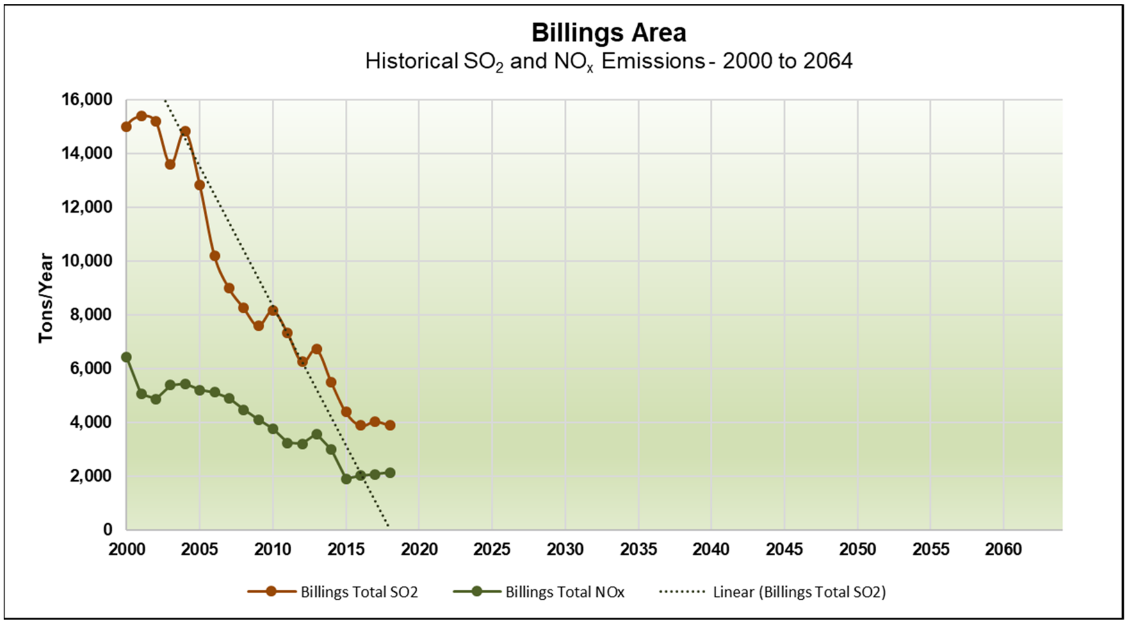

Figure 6: Billings Area SO_2 and NO_x Emissions from 2000 to 2064

This graphic indicates there has been a continuous dramatic reduction in emissions since the inception of the RHR program. On its face, this is a demonstration that there has been more than reasonable progress toward the national goal (assuming emissions were to have a direct effect on improvement in visibility). The graphic also indicates that the Billings area has, at this point, more than sufficiently contributed to the nationwide goal of the RHR program and no further action is recommended for Round 2.

4.4 YELP Emissions and Perspectives

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

As previously discussed, additional controls for YELP were considered by EPA during the first planning period, but no additional controls were determined to be appropriate given the size of the facility, the cost of compliance, and minimal visibility impacts, based on overall emissions and distance to Class I areas. Therefore, the FIP did not propose nor promulgate any additional controls for this facility.

In a broader perspective, Montana and more particularly Billings-area emission inventory data (shown above) clearly shows substantial reductions in SO_2 and NO_x emissions in the period since 2000 (and earlier although not shown in the figures as a matter of convenience). These reductions have resulted from voluntary source actions, implementation plans, plant closures, new plant constructions, and numerous consent decrees. Annual SO_2 emissions in Billings have fallen over 84% since 1994; 74% since 2002 (approx. start of RHR program). More notably, a 53% reduction in SO_2 emissions has been realized for the first planning period (2008 to 2018). These statistics are clear evidence that emission reductions from the Billings area are well ahead of any desired "uniform rate" of visibility improvement or progress contemplated to date at any nearby Class I area [7].[12] The "uniform rate of progress" line is also referred to as the glidepath, which is the linear representation of the visibility improvement needed to get from the baseline at a Class I area to its "natural background" in 2064.

To be consistent with previous historical (and projected) emission summaries, the same information is provided graphically below for the RHR program history.

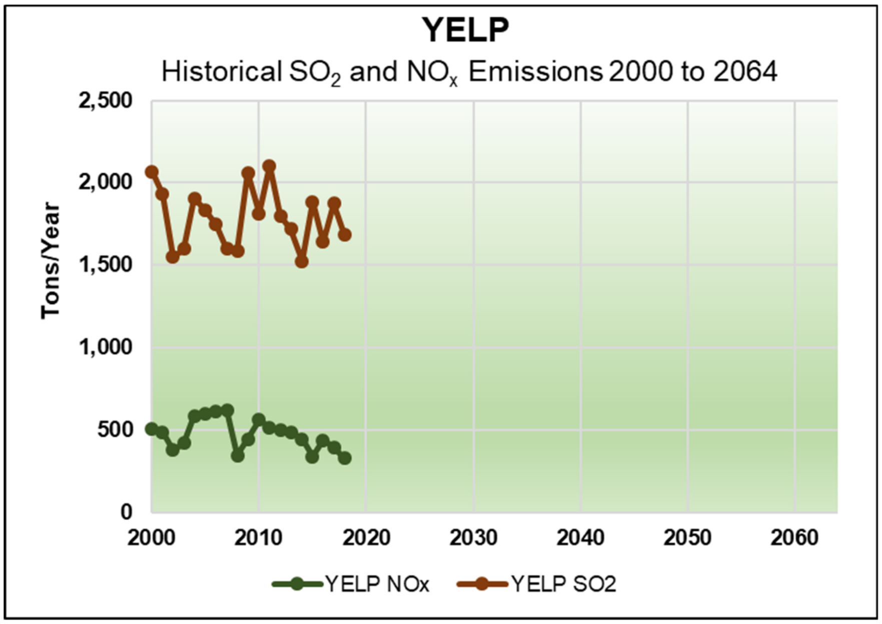

Figure 7: YELP SO_2 and NO_x Emissions from 2000 to 2064

YELP is the most recently constructed of the large Billings industrial facilities and provides power generation in addition to providing the ExxonMobil Billings Refinery with steam. Given the very efficient nature of the CFBC Boiler and the nature of YELP's business, the consistent operation and emission profile is to be expected. Consistent operations, however, does not correlate to visibility impairment, as will be discussed further.

4.5 Emissions vs Visibility Impairment Analysis

The next step in the reasonable progress perspective is to analyze the current and historical visibility measurements against facility-produced 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

[12] These uniform rates of progress for Montana's Class I areas are taken in general terms from those "glidepaths" shown in "State of Montana Regional Haze, 5-Year Progress Report," MDEQ, August 2017, Appendix C, Figures 9, 31, 42, 64, 53, 75, 86, 97 and 108.

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 YELP itself or combined with other nearby sources.

In addition to emissions data, there is concurrent visibility data at all the 'nearby' Class I areas. Visibility data from these areas was taken from the Western Regional Air Partnership (WRAP)[8] and generated from the Interagency Monitoring for Protected Visual Environments (IMPROVE)[1,2,9]. These areas and their closest proximity to YELP are shown below.

Table 1: Nearby Class I Areas and Proximity

Nearby Class I Area	**Approximate Distance from YELP (*kilometers*)**
North Absaroka Wilderness Area	144
Yellowstone National Park	146
UL Bend Wilderness Area	190
Gates of the Mountains Wilderness Area	270
Theodore Roosevelt National Park	405

Emissions data from YELP is provided for both the baseline period for the visibility program (2000 to 2004) as well as Round 1 (2005 to 2018) with respect to those Class I areas. As stated previously, Round 1 encompassed the analysis and implementation of BART along with a four-factor analysis that took place concurrently.

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 YELP 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 YELP has a relatively consistent emissions profile during the monitoring period (2000 to present), it is logical to assume that the deciview parameter would follow this trend.

The sections below provide such a comparison between emissions and various nearby Class I areas, first graphically, then with respect to statistical correlation.

4.5.1 North Absaroka Visibility vs Emissions

The first Class I area for consideration is the North Absaroka Wilderness area because it is the closest to YELP at roughly 144 kilometers from the facility to the border of the wilderness area. As with the analyses that follow, the visibility/glidepath data used in this analysis were taken from the WRAP Technical Support System [1,2].

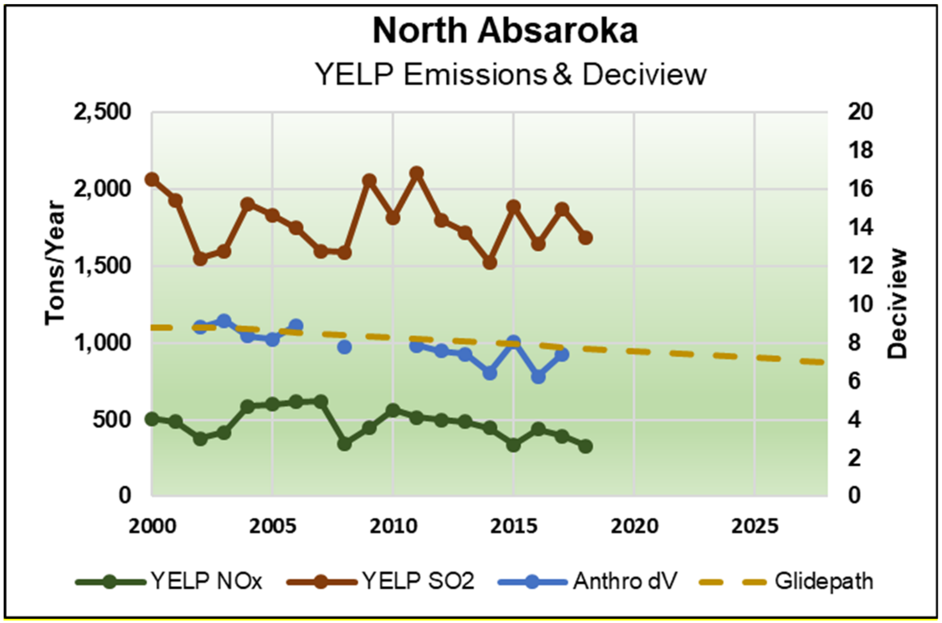

Figure 8: YELP SO_2 and NO_x Emissions from 2000 to 2018 compared with the North Absaroka Wilderness Area visibility glidepath through 2028

The analysis starts by a graphical review of the emissions and visibility data over time. The figure compares visibility (Anthro dV refers to anthropogenic deciview impairment) and the RHR glidepath at North Absaroka Wilderness Area with YELP SO_2 and NO_x data. 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.

The most important observation to be gleaned from this chart is that the observed deciview data indicates that this Class I area is already exceeding the uniform rate or progress requirement on its glidepath. If there is no change in emissions from all SO_2 and NO_x sources (Billings and otherwise) and all other parameters remain the same, the North Absaroka area will have achieved the glidepath at the end of 2028 without any reductions required during Round 2.

To complete the evaluation a correlation analysis is also presented in *Appendix A.* Specifically, the Pearson Correlation Coefficient (r) was determined. The correlation coefficient measures the linear correlation between two variables as shown in *Appendix A*, for example comparing YELP’s SO_2 emissions with the glidepath (multiple variables are compared). The value of “r” may vary from -1 to +1. A value of -1 indicates a negative correlation (when one variable increases, the other variable decreases). A value of zero indicates not correlation whatsoever and a value of +1 indicates a positive correlation.

The other variable of interest is r^2 (the square of the correlation coefficient r). This variable is useful because it gives an indication of the strength of a correlation. In general, the r^2 value is an indication of what percentage of the data fits the linear model of a correlation between the two variables. For example, an r^2 value of 0.50 would indicate that roughly 50% of the data fits the linear model well. Or put another way, 50% of the data suggests a good linear correlation and 50% of the data suggests no correlation.

For example, in this instance, YELP NO_x emissions had a potentially slight relation to Anthro dV (overall human caused visibility impairment)[13] and Anthro NO_3 (the portion of anthropogenic visibility impairment tied to NO_3 compounds) at r values of 0.20 and 0.40, respectively, but only 0.04 and 0.16 of the data would fit the linear model, based on the r^2 value (so no correlation). With respect to SO_2, no correlation is observed, particularly noting that Anthro SO_4 (the portion of anthropogenic visibility impairment tied to NO_3 compounds) trended slightly in the opposite direction from YELP SO_2 emissions. The statistical analyses show no relationships between the visibility data at North Absaroka and YELP emissions.

4.5.2 Yellowstone National Park Visibility vs Emissions

Yellowstone National Park is the next Class I area for consideration. It is roughly 146 kilometers from the facility to the border of the wilderness area. The figure compares visibility (Anthro dV) and the RHR glidepath at Yellowstone National Park with YELP SO_2 and NO_x data. In reviewing the figure below, the observed visibility at the site seems, on the whole, to be following the designed glidepath.[14] The graphical data from YELP appear to be unrelated to the Yellowstone visibility data.

[13] The term anthropogenic deciview here is in reference to the definition of “Most impaired days” per 40 CFR 51.301.

[14] The “glidepath” is a straight line of deciviews starting at the baseline (≈ 2000-2004) through the 2064 endpoint of the RHR program. The “endpoint” is the final desired deciviews which represents “remedying of … existing impairment of visibility … which … results from manmade pollution.” (Clean Air Act). If visibility is following this glidepath it is evidence of reasonable progress towards the national goal.

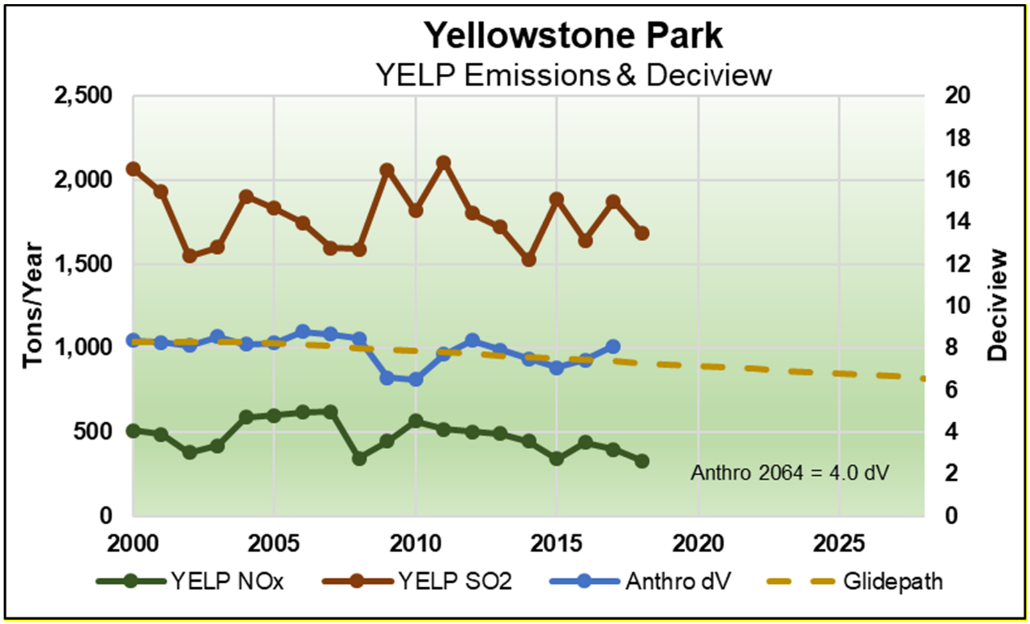

Figure 9: YELP SO_2 and NO_x Emissions from 2000 to 2018 compared with the Yellowstone National Park visibility glidepath through 2028

The full correlation analysis results are available in *Appendix A*, but no evident correlations are seen for YELP.

4.5.3 UL Bend Wilderness Visibility vs Emissions

Another Class I area to consider is the UL Bend Wilderness. This area is located about 190 kilometers north-north east of the YELP facility. A graphical review of the emissions and visibility data over time is provided below.

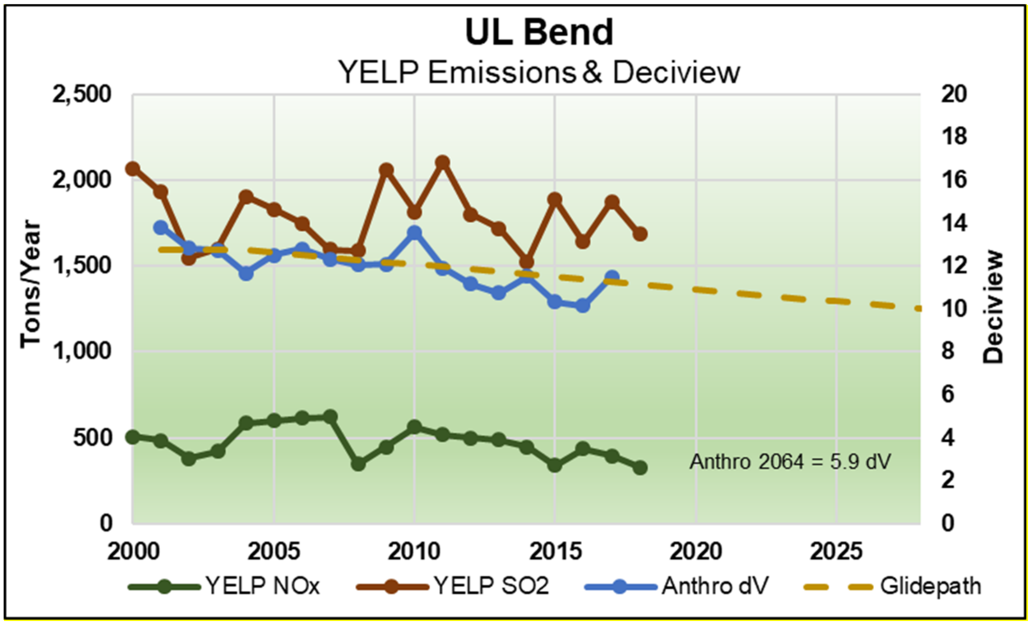

Figure 10: YELP SO_2 and NO_x Emissions from 2000 to 2018 compared with the UL Bend Wilderness Area visibility glidepath through 2028

The graphic seems to indicate that the glidepath and observed deciview data match relatively closely. Thus, data to date shows that the area is meeting the uniform rate of progress (glidepath) that RHR prescribes.

The full correlation analysis results are available in *Appendix A*, but no evident correlations are seen for YELP.

4.5.4 Gates of the Mountains Wilderness Area Visibility vs Emissions

The Gates of the Mountains Wilderness Area was selected as another Class I area to review. However, the area is about 270 kilometers west/northwest of the YELP facility making it an area very unlikely to be impacted. Nonetheless and review of that data was undertaken. A graphical review of the emissions and visibility data over time is provided below.

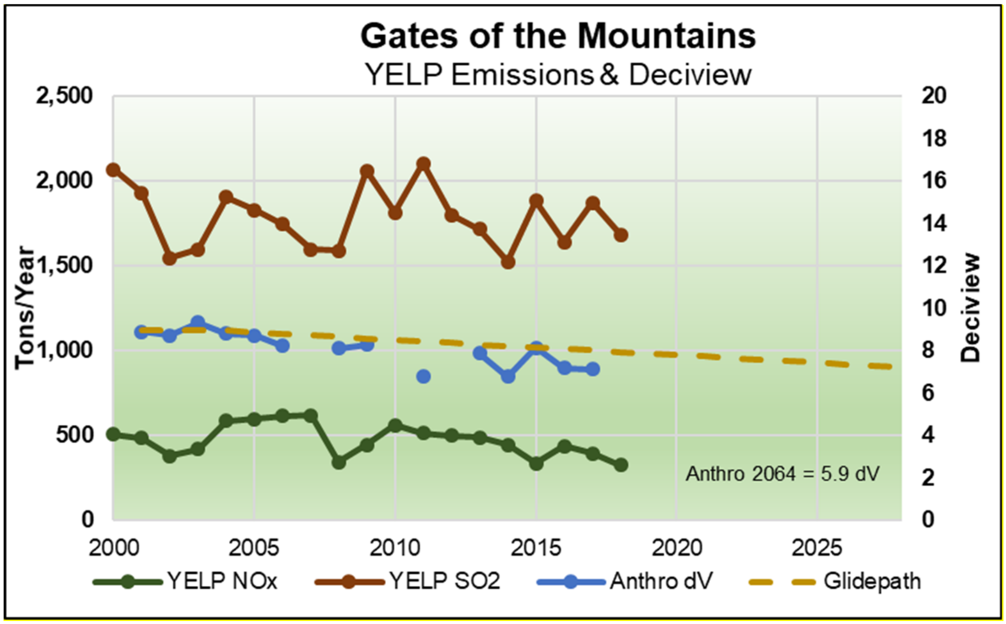

Figure 11: YELP SO_2 and NO_x Emissions from 2000 to 2018 compared with Gates of the Mountains Wilderness Area visibility glidepath through 2028

The graphic reveals two interesting features. The visibility improvement is ahead of the desired uniform rate of progress wanted for the program. And, the current visibility (mean for past 5 years) is at or near the desired level for this 2nd planning period.

The full correlation analysis results are available in *Appendix A*, but no evident correlations are seen for YELP.

4.5.5 Theodore Roosevelt National Park Visibility vs Emissions

The final Class I area of interest is the Theodore Roosevelt National Park. This Class I area is approximately 400 kilometers from YELP and is therefore highly unlikely to be impacted by YELP SO_2 or NO_x emissions. Nonetheless, because this area has been the subject of interest by the State of North Dakota and EPA Region VIII, it was included in this analysis. The visibility versus emissions information is presented in graphical form below.

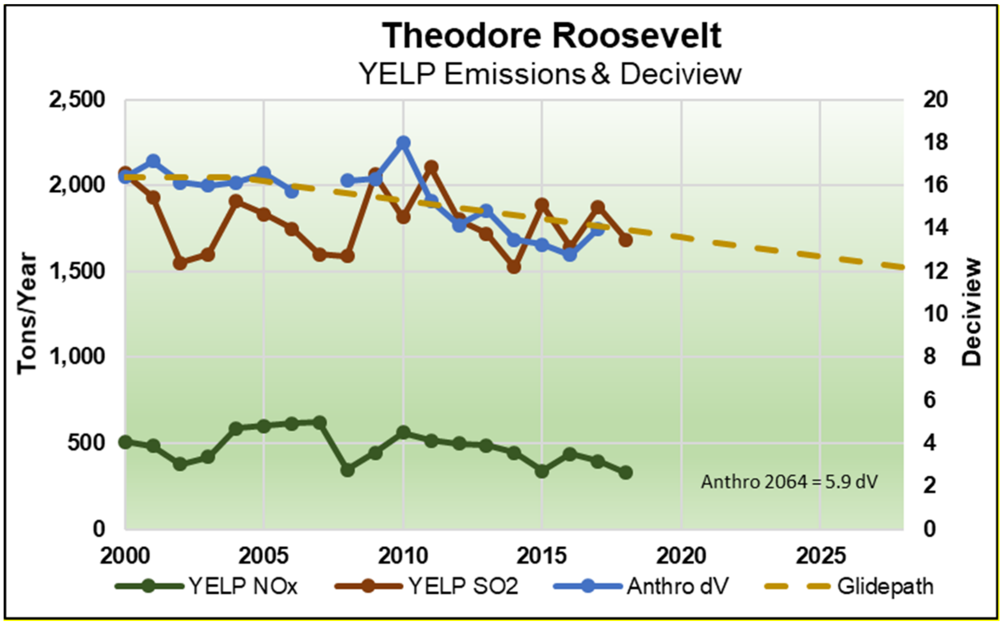

Figure 12: YELP SO_2 and NO_x Emissions from 2000 to 2018 compared with Theodore Roosevelt National Park visibility glidepath through 2028

Although not specifically portrayed in the graphic, there is a notable trend in visibility improvement in the past 10 years. This corresponds to the same 10-year period of implementation of the 1st planning period. The emissions from YELP, however, do not share this same trend as YELP sees a more consistent emissions profile (and operation) over time.

Given the great distances involved and the fact that there is no noted correlation between visibility data and YELP emissions, it is reasonable to conclude that YELP is not a candidate for emissions reductions to improve visibility at this National Park.

5.0 FOUR-FACTOR ANALYSIS

The following four-factor analysis was completed for YELP in response to the March 13, 2019 email from MDEQ. This facility was selected by MDEQ because of a "Q/d" analysis used by MDEQ to screen facilities for Round 2.[15] MDEQ's analysis used 4.0 as the action threshold for determining enrollment into Round 2. The YELP facility had a Q/d of 14.86, over the action threshold, when utilizing 2014-2017 average annual emissions. As previously mentioned, additional controls for YELP were considered by EPA during Round 1 using the four-factor analysis and process. That analysis is revisited and updated for this discussion.

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 SO_2 Control Measures

Several techniques can be used to reduce SO_2 emissions from fossil fuel combustion sources. SO_2 control options can be divided into pre-combustion strategies (e.g., combusting low sulfur fuels, fuel blending, coal cleaning, etc.), combustion techniques (e.g., types of boilers, turbines, etc.), and post-combustion controls (e.g., wet scrubbers, dry scrubbers, etc.).

YELP currently controls SO_2 emissions using limestone injection. Limestone is injected with the petroleum coke prior to its combustion in the two boilers. In the boilers, the limestone calcines to lime and reacts with SO_2 to form calcium sulfates and calcium sulfites. The calcium compounds are removed as particulate matter by the baghouses. Depending on the fuel fired in the boilers and the total heat input, YELP must control SO_2 from 92% reduction for all boilers operating hours per Montana Operating Permit #OP2650-02. The current limestone injection system is operating at or near its maximum capacity and increasing limestone injection beyond the current levels would likely result in plugging of the injection lines, increased bed ash production which can reduce combustion efficiency, and increased particulate loading to the baghouses. Increasing limestone beyond its current level would require major upgrades to the limestone feeding system and the baghouses. Furthermore, an upgrade to the existing limestone injection system would expect only modest increases in SO_2 removal efficiency compared to add-on SO_2 control systems which were further analyzed within this section. Therefore, upgrading the existing system is not considered further. This analysis will focus add-on control systems for SO_2 control.

[15] See email letter from MDEQ dated March 13, 2019

5.1.1 SO_2 Control Technologies Considered

As YELP's fuel type (petroleum coke and coker gas), type of boiler (Circulating Fluidized Bed Combustion), and existing limestone system are operating at current maximum capacity, this four-factor analysis will focus on post-combustion controls to further reduce sulfur dioxide emissions beyond the existing limestone injection control. The post-combustion controls that are potentially technically feasible in this application are flue gas desulfurization (FGD) systems. FGD options for CFBC boilers include: Wet Lime Scrubber, Wet Limestone Scrubber, Dual-Alkali Scrubber, Spray Dry Absorber, Dry Sorbent Injection, Circulating Dry Scrubber, and Hydrated Ash Reinjection. Each control system is briefly described as follows.

Wet Lime Scrubber

The wet lime scrubbing process uses alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills. A review of the RBLC database has found limited applications of this technology on CFBCs firing petroleum coke.

Wet Limestone Scrubber

Wet limestone scrubbers are very similar to wet lime scrubbers. However, the use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Wet lime/limestone scrubbers can achieve SO_2 control efficiencies of approximately 95% or greater when used on boilers burning higher sulfur fuels but may achieve lower control efficiencies on lower sulfur-content fuels. The actual control efficiency of a wet lime/limestone FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber. Like wet lime scrubbers, wet limestone scrubbers generate sludge that can create material handling and disposal issues. A review of the RBLC database has found limited applications of this technology on CFBCs firing petroleum coke.

Dual Alkali Wet Scrubber

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop.

The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber. A review of the RBLC database has found limited applications of this technology on CFBCs firing petroleum coke.

Spray Dry Absorber

The typical spray dry absorber (SDA) uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate control device, and recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

Dry Sorbent Injection

Dry sorbent injection (DSI) involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. The dry sorbent is typically injected countercurrent to the gas flow through a venturi orifice. An expansion chamber is often located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system's particulate control device.

SO_2 control efficiencies for dry sorbent injection systems are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

Circulating Dry Scrubber

A third type of dry scrubbing system, the circulating dry scrubber (CDS), uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system.

Hydrated Ash Reinjection

The hydrated ash reinjection (HAR) process is a modified dry FGD process developed to increase utilization of unreacted lime (CaO) in the CFBC ash and any free lime left from the furnace burning process. The hydrated ash reinjection process will further reduce the SO_2 concentration in the flue gas. The actual design of a hydrated ash reinjection system is vendor specific. In a hydrated ash reinjection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFBC applications, sufficient residual CaO is available in the ash and additional lime is generally not required.

5.1.2 Eliminating Technically Infeasible Options

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. YELP has high efficiency fabric filters in place. Based on limited technical data from non-comparable applications and engineering judgment, it has been determined that CDS is not technically feasible with a CFBC boiler equipped with a fabric filter for particulate control. Therefore, the CDS will not be evaluated further.

The YELP facility has a very limited area to install additional SO_2 controls and manage waste materials (see *Figure 13*). The wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, Dual Alkali Wet Scrubber) would require an on-site dewatering pond or landfill to dispose of scrubber sludge. Due to YELP's limited space requirements, its proximity to the Yellowstone River, and limited water availability for these controls, these technologies are considered technically infeasible and will not be evaluated further.

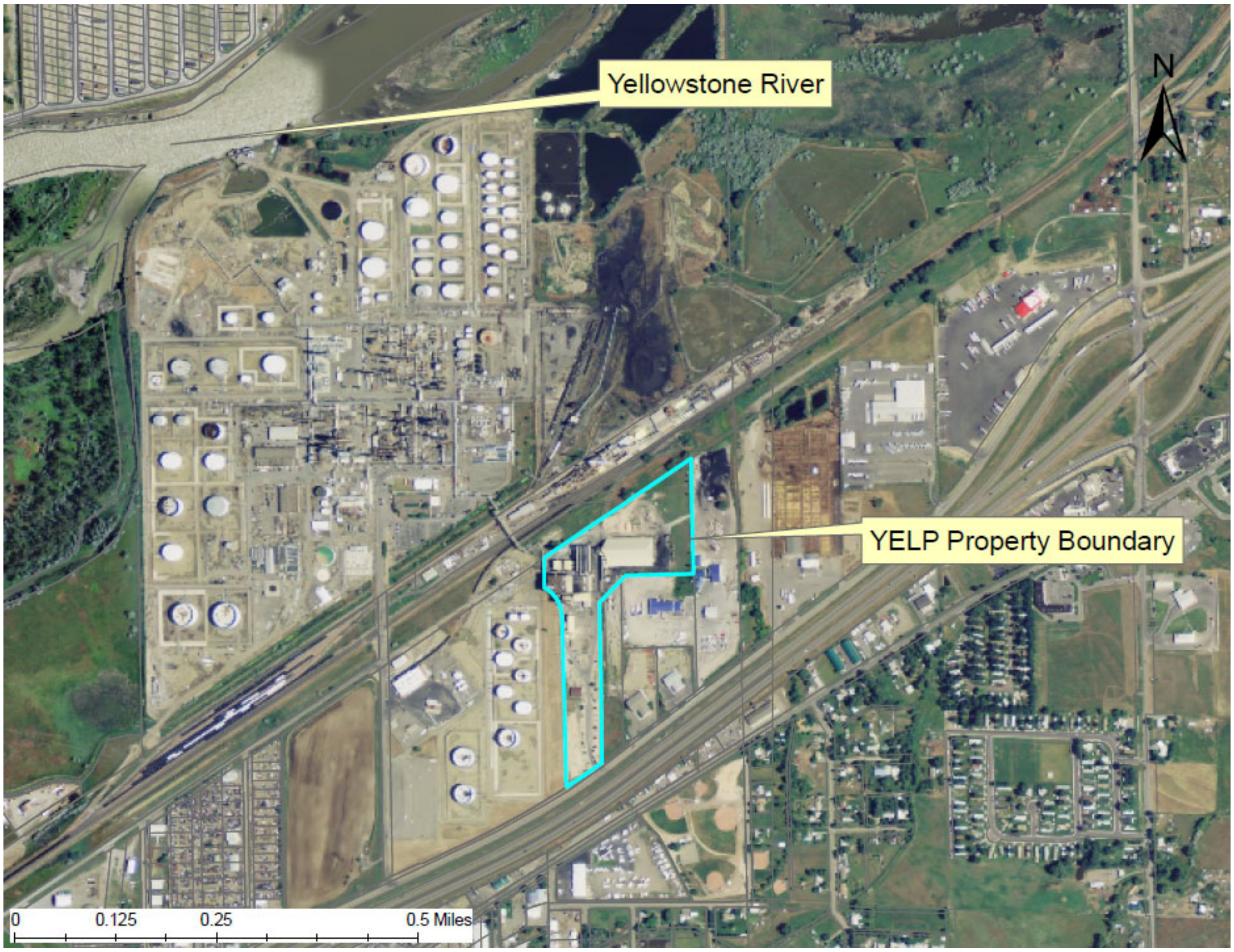

Figure 13: YELP Property Boundary and Proximity to Yellowstone River

5.1.3 Identify Technically Feasible Options

Technologies requiring low amounts of water and installation space were evaluated. The three technically feasible control options for the YELP facility were determined to be HAR, SDA, and DSI.

The ability of the existing fabric filter baghouses at YELP to accommodate additional particulate resulting from HAR, SDA or DSI is in question based on prior conversations with a vendor of these systems. The vendor previously indicated that the baghouse design must be matched with the add-on control systems and its resulting particulate loading. Therefore, the existing baghouse system would need to be replaced or potentially redesigned significantly to accommodate the increase in particulate in the flue gas stream. As a result, we have included a redesigned (new) fabric filter baghouse in the cost for each SO_2 control technology. The costs of these feasible technologies will be discussed in *Section 5.3*.

5.2 NO_x Control Measures

Applicable NO_X control technologies can be divided into two main categories: combustion controls, which limit NO_X production, and post-combustion controls, which destroy NO_X after formation.

YELP currently controls NO_x emissions using good combustion practices in the CFBC boilers.[16] Emissions are controlled through the boiler design and its lower operating temperatures, and a recirculation of fuel and ash particles through the combustion boiler. The lower operating temperature in a CFBC boiler already reduces the formation of thermal NO_x emissions in the range of 50% or more compared to other boiler designs. YELP must meet emission limits of 0.400 lb/MMBtu and 319.0 pounds per hour per #OP2650-02. YELP demonstrates compliance with these limits using continuous emission monitors and EPA Method 7/7E.

5.2.1 NO_x Control Technologies Considered

As YELP is currently using boiler design to control NO_x emissions, only post-combustion controls were considered for this analysis. The post-combustion controls that are initially technically feasible in this application are Low Excess Air (LEA), Flue Gas Recirculation (FGR), Overfire Air (OFA), Low NO_x Burners (LNB), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR).

Low Excess Air

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_X and lowers the peak flame temperature, which inhibits thermal NO_X formation.

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels.

This technology is typically utilized on Pulverized Coal (PC)-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

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[16] CFBC combustion technology design has inherently lower combustion temperatures than pulverized coal technology. The lower combustion temperature of a CFBC boiler (1550 – 1650ºF) typically leads to a lower formation of thermal NO_x than a PC boiler, which has a relatively higher combustion temperature (2400 – 2700ºF) and more thermal NO_x.

Flue Gas Recirculation

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the O_2 concentration in the combustion zone.

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

Overfire Air

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_X. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Having combustion occur over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_X formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler.

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

Low NO_X Burners

LNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_X formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_X is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel-lean zone where combustion is completed. LNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs.

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC because the combustion occurs within the fluidized bed.

Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique that uses a catalyst to reduce NO and NO_2 to molecular nitrogen, water, and oxygen. Ammonia (NH_3) is commonly used as the reducing agent.

Ammonia is vaporized and injected into the flue gas upstream of the catalyst bed and combines with NO_X at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_X and ammonia.

Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_x reduction in the range of 80% to 90+% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst.

SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. High dust SCR units can be installed on solid fuel combustion units before the particulate control device, but they have their limitations.

Selective Non-Catalytic Reduction

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. A NO_x reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1600 to 2100°F are required.

Typical NO_x control efficiencies range from 40% – 60%. NO_x removal efficiency varies for this technology, 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 presence of interfering chemical substances in the gas stream.

5.2.2 Eliminating Technically Infeasible Options

Because OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NO_x, these control options are technically ineffective on a CFBC boiler that has inherently low combustion temperatures and relatively lower thermal NO_x. Further, a CFBC boiler does not use burners like a PC boiler, limiting the available combustion control options. The remaining post combustion NO_x control options are considered technically feasible.

5.2.3 Identify Technically Feasible Options

SCR and SNCR are considered technically feasible options for NO_x control of the YELP boilers for the purpose of this analysis. However, both control technologies have difficulties in design, construction, and implementation. Most notably, SCR control creates a high risk of causing superheater damage due to the interaction of vanadium in petroleum coke and the SCR catalyst. Likewise, the YELP facility has a very limited area to install additional controls and manage waste materials as mentioned in *Section 5.1.2*. These space limitations also apply to the potential installation of SCR and SNCR. Both control technologies are still evaluated however these technical limitations are described further in the energy and non-air environmental compliance section (Factor 3) and the summary.

An in-depth description of each control system is detailed in the following sections.

5.2.3.1 SCR

Theoretically, SCR systems can be designed for NO_x removal efficiencies up close to 100 percent. In practice, new commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_x controls such as LNB or FGR that achieve relatively low emissions on their own (including CFBC boiler technology). The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu) [12,13][17]. Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for the YELP Boilers is 80% as provided by vendor data detailed in Factor 1.

With respect to reagents, either ammonia or urea may be used as the NO_x reduction reagent in SCR systems. Urea is generally converted to ammonia before injection. Results of a survey of electric utilities that operate SCR systems indicated 80 percent use ammonia (anhydrous and aqueous), and the remainder use urea [13]. Additionally, a survey of coal-fired power plants that control NO_x emissions using either SCR or SNCR found anhydrous ammonia use exceeds aqueous ammonia use by a ratio of 3 to 1 [13]. Nearly half of these survey respondents indicated that price is their primary consideration in the choice of reagent with safety second. Because ammonia is most commonly used for this type of unit and was provided in the vendor quote, it was used in the reagent calculations for the YELP Boilers [14].

Ammonia or urea is injected into the flue gas upstream of a catalyst bed, and NO_X and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction.

[17] Data in the Clean Air Markets Division (CAMD) database also suggest SCR units rarely achieve emissions less than 0.04 lb/MMBtu.

Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), noble metals (e.g., platinum and rhodium), zeolite, and ceramics.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. Technical factors that impact the effectiveness of this technology include inlet NO_X concentrations, the 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.

In retrofit installations, new ductwork would be required to integrate the SCR system with the existing equipment. In low-dust SCR systems for utility and industrial boilers, the SCR reactor would be located between the outlet duct of the particulate control device and the air heater inlet duct.

Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion [15]. Specific factors that impact the retrofit costs include the following [13]:

- Amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing particulate control, flue gas desulfurization (FGD) system, induced draught (ID) fan, or stack);
- Age/vintage and manufacturer of the boiler;
- Design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- Capacity, condition, and design margins of the electrical distribution system;
- Design margins of the existing structural steel support systems;
- The positive and negative design pressure of the furnace and existing particulate control; and
- Number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

5.2.3.2 SNCR

Per the April 2019 update of the EPA Cost Control Manual [16], SNCR is a post combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. This technology is often used for mitigating NO_x emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber.

SNCR involves the noncatalytic decomposition of NO_X in the flue gas 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 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. 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.

The process has been used in North America since the early 1980s and is most common on utility boilers, specifically coal-fired utility boilers. Removal efficiencies of NO_X vary considerably for this technology, 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.

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology, and this portion has been growing over time. Ammonia is generally less expensive than urea because urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. Ammonia was employed as the reagent in the YELP SNCR cost analysis because it was determined to be the most appropriate reagent by the vendors and was included in the vendor quote. An average reduction of 50% was used in the cost efficiency calculations because that was selected/determined to be feasible in the vendor quote.

For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied with existing boiler equipment such as the watertubes. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The estimated costs on a $/kW basis increase sharply for small boilers due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The YELP boilers combine for 65 MW and therefore are considered small boilers.

5.3 Factor 1 – Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. These categories of costs include categories such as direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance for SNCR and SCR [17].

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the CFBC Boilers were taken from the baseline emission rate agreed to by MDEQ of the 2014 – 2017 average annual emissions.

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy and applying the 5.5% as the interest rate noted by MDEQ in their April 19, 2019 email correspondence. The resulting cost of compliance is presented in Tables 2 and 3. Details of the calculations may be found in *Appendix B*.

5.3.1 SO_2 Cost Effectiveness

The cost-effectiveness of the technically feasible SO_2 control technologies were estimated based on the methodologies developed by William M. Vatavuk in the book "Estimating Costs of Air Pollution Control" [18] and the methodologies provided in EPA's Office of Air Quality Planning and Standards (OAQPS) Pollution Cost Control Manual, 6th Edition [19]. Each cost analysis is based on the methodology described in Cost Control Manual Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal. The cost effectiveness was estimated using the OAQPS example for Acid Gas Removal because it most closely reflected the control methods being assessed when compared to the other OAQPS choices. This same methodology was utilized in the Round 1 analysis.

Equipment and system operations have remained the same at YELP since the Round 1 analysis was accepted by the EPA in 2011. Therefore, the Round 1 cost analysis has been updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation.[18]

The average of YELP SO_2 emissions from 2014 to 2017 was used to estimate the cost-effectiveness of the technically feasible control options. The results of the analysis are summarized in *Table 2*. Detailed calculations and supporting information are provided in *Appendix B* – Cost Analysis. All three control options include the cost of installing the designated control option as well as the corresponding, upgraded baghouse system.

[18] Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

Table 2: Estimated Costs of SO_2 Control Options for YELP

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFBC with Hydrated Ash Reinjection and Baghouses	50%	**$35,816,983**	**$5,796,240**	**866**	**866**	**$6,693**
CFBC with Spray Dry Absorbers and Baghouses	80%	**$45,276,409**	**$7,509,313**	**1,386**	**346**	**$5,420**
CFBC with DSI and Baghouses	50%	**$23,446,964**	**$5,062,421**	**866**	**866**	**$5,846**

The costs for additional control of the boilers are cost prohibitive. Initial discussions with MDEQ indicated "Best Available Control Technology (BACT) level" costs would be considered for the four-factor analysis process. As previously discussed, the calculated costs above incorporate the additional cost of an upgraded baghouse system. These costs exceed BACT level cost per ton values at recently permitted units.

5.3.2 NO_2 Cost Effectiveness

During the Round 1 analysis, YELP consulted with Bison, the Harris Group, and Metso to estimate the cost-effectiveness of installing SCR or SNCR at the facility. Metso and the Harris Group have extensive experience building CFBCs with NO_x controls. Their expertise was utilized to develop as close to an estimate of each control technology as possible.

The cost-effectiveness of the technically feasible NO_x control technologies was estimated using the Round 1 total capital and operating cost estimates developed by Metso, the Harris Group, and by the Office of Air Quality Planning and Standards Pollution Cost Control Manual, 6th Edition [19]. The newly published 2019 control cost manual analyses for SCR and SNCR were not utilized in Round 2 since the YELP boilers are not accurately represented within the spreadsheet calculations. The YELP boilers are dual purpose and create steam for the ExxonMobil refinery as well as power generation. It is difficult to provide accurate input data for the YELP boilers within the utility or industrial functions of the spreadsheet. The 2019 calculations also do not provide representative fuel characteristics for the utilization of petroleum coke and coker gas at YELP. The Metso and Harris Group cost estimates were provided specifically for the YELP facility and provide the most reasonable estimate for this stage of planning. Therefore, the 2011 analyses were revised utilizing the vendor specific cost estimates.

Again, equipment and system operations have remained the same at YELP since the Round 1 analysis was accepted by the EPA in 2011. Therefore, the Round 1 cost analysis for NO_x has also been updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation

The average of YELP NO_2 emissions from 2014 to 2017 was used to estimate the cost-effectiveness of the technically feasible control options. The results of the analysis are summarized in *Table 3*. Detailed calculations and supporting information are provided in *Appendix B* – Cost Analysis. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

Table 3: Estimated Costs of NO_2 Control Options for YELP

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFBC with Selective Catalytic Reduction	80%	**$32,460,400**	**$4,153,623**	**323**	**81**	**$12,841**
CFBC with Selective Non-Catalytic Reduction	50%	**$1,020,800**	**$597,303**	**202**	**202**	**$2,954**

The costs for additional NO_x control of the boilers vary and are difficult to accurately estimate at a preliminary design stage. Due to space limitations causing constraints in design capabilities, these proposed costs are an initial estimate for installing the add-on control systems with limited knowledge of the YELP network equipment (i.e., plant piping, cable piping, etc.). As noted in the Metso report, this is an order of magnitude estimate because there could be interferences and significant unknowns that would alter Metso's cost estimates. Additional investment would be required from YELP to determine a more refined cost estimate.

Additionally, the vendor cost estimates do not account for lost revenue due to facility downtime. The time necessary for compliance is detailed in Factor 2 and describes YELP's operating relationship with the ExxonMobil Billings Refinery. Lost revenue due to facility downtime would increase the total annual costs associated with adding on emissions controls.

5.4 Factor 2 – Time Necessary for Compliance

The ExxonMobil Billings Refinery relies on the consistent operation of the YELP boilers for steam production, which is intrinsic to refinery operation. Therefore, any major facility downtime or retrofits at YELP will have to be coordinated with ExxonMobil. Likewise, YELP provides environmental benefits to Exxon by scrubbing the refinery coker flue gas emissions. A shutdown of YELP would result in a complete loss in the ability for Exxon to efficiently control the corresponding coker gas. Therefore, any major control installation at either boiler would ultimately have to work in conjunction with ExxonMobil's maintenance schedule. The following subsections provide time estimates based on vendor data once YELP and ExxonMobil would be able to agree on a feasible downtime.

5.4.1 Installation of SO_2 Controls

The addition of HAR, SDA, or DSI would each take approximately the same amount of time. However, as stated previously, the addition of SO_2 controls would likely require complete replacement or major modifications to the existing baghouses. The installation of the new SO_2 controls and baghouses should be staggered to allow one boiler to remain in operation while the retrofits are applied to the other boiler. Bison estimates that the time necessary to complete the modifications to one boiler would be approximately four to six months. A boiler outage of approximately two to three months per boiler would be necessary to perform the installation of both control systems. The total time necessary to install the controls would be approximately one year.

5.4.2 Installation of NOx Controls

Due to the complexity of the existing infrastructure and severely limited space, the installation of SCR is estimated to take approximately 26 months. The installation of SNCR is less complex and would take approximately 24-30 weeks. Please see the attached report included in *Appendix B* for more information.

5.5 Factor 3 – Energy and Non-air Environmental Impacts

5.5.1 Energy Impacts: SO_2 Controls

FGD systems require electricity to operate. The FGD systems being analyzed use electricity primarily for the ID fan, lime/limestone handling equipment and baghouse blowers. SDA, DSI and HAR systems have been estimated to consume 0.1% to 0.5% (parasitic load) of the total plant generation.

5.5.2 Energy Impacts: NOx Controls

The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. On the other hand, SCR would cause a significant backpressure in the CFBC boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, YELP would be subject to the additional cost of reheating the exhaust gas, which is an inefficient use of energy and additional fuel.

5.5.3 Non-Air Quality Impacts: SO_2 controls

The addition of the SO_2 controls would result in increased ash production at the YELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. The loss of this market would cost YELP approximately $2,300,000 year at the current ash value and production rates (approximately 170,000 tons of ash/year). The loss of this market would also result in BGI having to dispose of the ash at its current landfill, which is approximately 80 miles from the YELP plant. YELP currently pays a fixed fee of approximately $500,000 a year to manage this landfill. YELP incurs a fee of $3.56/ton on ash taken to the pit that is in excess of 140,000 tons/year. At its current production and ash disposal costs, this would result in an increased cost to BGI of approximately $96,000/year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $2,400,000/year.

Another potential impact would be to mercury emissions. YELP has recently determined that mercury content in its limestone feed has contributed to a violation of the federal Mercury Air Toxics Standard. Additional use of limestone (which is included in the SO_2 controls listed above) would trigger added costs and control to address potential mercury emissions resulting from that limestone.

5.5.4 Non-Air Quality Impacts: NOx Controls

The addition of chemical reagents in SNCR and SCR controls would add equipment for its storage and use. The storage of on-site ammonia would pose a risk from potential releases to the environment. An additional concern is the loss of ammonia, or “slip” into the emissions stream from the facility; this “slip” contributes another pollutant to the environment, which has been implicated as a precursor to fine particulate formation in the atmosphere. The additional costs of chemicals and catalysts have been included in the cost analysis.

SCRs can also contribute to fouling in backpass equipment due to ammonia bisulfate formation. Equipment fouling could reduce unit efficiency and increase flue gas velocities. Additionally, the ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste. On some installations, catalyst life is very short, and SCRs have fouled in high dust environments. This had led to boiler downtime in some installations. The presence of vanadium in the petroleum coke fuel has also led to reduced catalyst life on SCR units. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor. Metso details the risks associated with using SCR to control boilers using petroleum coke as fuel. Regarding vanadium poisoning SCR catalyst, the vendor states in their proposal in *Appendix B* that:

> "It is proven that vanadium poisons SCR catalysts. The catalyst life for this unit is likely to be short (likely months instead of years). This will likely reduce the availability of this unit and subject the facility to significant operating and maintenance costs. The catalyst life is difficult to quantify without a further extensive study by a catalyst supplier. It is unlikely or would be costly to obtain a lengthy catalyst life guarantee from a catalyst supplier for this application.
>
> Fouling of petcoke fired units occurs on superheater surfaces. The superheater is upstream of this SCR. The fouling will likely cause plugging and blinding of the SCR catalyst when it breaks loose from the superheater surfaces. This will increase maintenance costs at this facility and subject the unit to increased downtime.
>
> Metso would be hesitant to install an SCR on a petroleum coke fired boiler."

5.6 **Factor 4 – Remaining Useful Life of Source**

The CFBC Boilers at YELP are not planned for retirement at this time. Therefore, as dictated in discussions and correspondence with MDEQ, the remaining useful life of the sources is assumed to be 20 years.

6.0 CONCLUSIONS

A four-factor analysis was conducted for the YELP facility to meet the requirements of "Round 2" of the RHR in order to develop a SIP addressing 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 YELP.

The four factors analyzed were based on the MDEQ correspondence and the RHR to determine if there are emission control options at YELP 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 SO_2 and NO_x on the CFBC boilers at YELP with additional discussion regarding facility-wide and regional emission reduction efforts. The Billings area, collectively, has made considerable investment in reducing emissions through the Refinery Consent Decree process as well as corporate efficiency initiatives and continues to be a good environmental steward. The downward trend in visibility-impairing pollutants, both NO_x and SO_2, was apparent in Section 3 of this analysis, as was the lack of correlation between YELP emissions and visibility in nearby Class I areas.

As requested by MDEQ, BGI has analyzed its two CFBC boilers at the YELP facility for the purposes of meeting the Reasonable Progress Goals of the Regional Haze Rule. BGI retained Metso, the Harris Group, and Bison to assist in evaluating possible control alternatives at YELP. The analysis identified two technically feasible controls for NO_x (SCR and SNCR) and three technically feasible controls for SO_2 (HAR, SDA, and DSI).

As part of the analysis, EPA requested that BGI analyze the costs of compliance. The EPA's document "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program" [20] states:

> "…the cost of compliance factor can be interpreted to encompass the cost of compliance for individual sources or source categories, and more broadly the implication of compliance to the health and vitality of industries within a state."

The two technically feasible NOx control options identified in the Metso study would have major impacts on the facility and its ability to remain in operation. To put this discussion in context, YELP has a long-term fixed rate contract through 2028 with NorthWestern Energy to sell its electrical output. That contract determines the rates to be paid, and does not allow any pass-through of any costs, whether capital, operating, financing, or otherwise. Therefore, to the extent it can do so, the entire burden (including lost revenue, as well as all other impacts) of implementation of any required control method will be borne by the YELP facility. The YELP facility has struggled to maintain operation and has done so through borrowing and depreciation. The YELP facility has never paid any return on equity. The YELP facility provides many benefits to the state and community, including a key environmental value by scrubbing ExxonMobil refinery coker flue gas (previously emitted) through its boilers, reducing materially the SO_2 content of the Billings, Montana, airshed.

As can be seen in this response and the attachments hereto, the two NO_x control options (SCR and SNCR) bring with them capital costs and installation of $32,460,000 and $1,020,000 and annual operating costs of $4,200,000 and $600,000, respectively. These operating costs would double or quadruple YELP's current budgeted costs for similar requirements. They also have the potential to cost the project on the order of $2,500,000 annually in lost revenue and incurred disposal costs for ash presently sold, and in the case of SCR, include an extraordinary downtime of two to three months for implementation, resulting in a loss of revenue which is neither insured nor passed through to NorthWestern.

The addition of SO_2 controls would have a similar impact to YELP's ability to remain in operation. Bison identified three technically feasible SO_2 controls, which are HAR (capital investment $35,800,000 - annual operating cost $5,800,000), SDA (capital investment $45,300,000 - annual operating cost $7,500,000), and DSI (capital investment $23,500,000 - annual operating cost $5,000,000), also bringing with them lost revenue and increased costs for ash disposal, and downtime of four to six months to modify YELP's boilers.

YELP has no capacity for further borrowing to implement the costs of any of the alternatives (SO_2 or NO_x), either for capital improvements or operations. The downtime alone for implementation of the SCR alternative or any of the SO_2 alternatives would cause YELP to be unable to meet ongoing operating cost obligations. YELP is financed, in part, by tax exempt bonds issued by the State of Montana. Should YELP be required to implement either alternative without a cost pass-through mechanism to the purchaser of its output, the outcome would be bankruptcy for YELP. The consequences to the community and state of such an event would be annual loss of about $18,000,000 in payroll, vendor payments, property taxes, etc., and default on about $220,000,000 in debt-related obligations, as well as the loss of the environmental benefits of scrubbing the ExxonMobil coker flue gas emissions.

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 controls on the CFBC Boilers are not necessary to make reasonable progress due to costs and YELP's lack of a measurable impact on any nearby Class I area, particularly in light of recent emissions reductions by other facilities in the state and Billings 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: CORRELATION ANALYSES

Visibility and NOx Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*YELP NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings NOx	0.74	-0.12	1			
	Glidepath	0.80	-0.11	0.96	1		
	Anthro NO_3	0.53	-0.40	0.78	0.76	1	
	YELP NOx	0.20	-0.27	0.52	0.48	0.40	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings NOx	0.54	0.02	1			
	Glidepath	0.64	0.01	0.92	1		
	Anthro NO_3	0.28	0.16	0.60	0.57	1	
	YELP NOx	0.04	0.07	0.27	0.23	0.16	1

Visibility and NOx Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*YELP NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Billings NOx	0.53	-0.22	1			
	Glidepath	0.48	-0.25	0.96	1		
	Anthro NO_3	0.37	-0.07	0.60	0.57	1	
	YELP NOx	0.23	-0.24	0.52	0.48	0.29	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Billings NOx	0.28	0.05	1			
	Glidepath	0.23	0.06	0.92	1		
	Anthro NO_3	0.14	0.01	0.36	0.32	1	
	YELP NOx	0.05	0.06	0.27	0.23	0.08	1

Visibility and NOx Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*YELP NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings NOx	0.72	0.08	1			
	Glidepath	0.74	0.07	0.97	1		
	Anthro NO_3	0.77	0.23	0.39	0.45	1	
	YELP NOx	0.34	-0.01	0.52	0.48	0.10	1

		Anthro dV	All dV	Billings NOx	Glidepath	Anthro NO_3	YELP NOx
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings NOx	0.51	0.01	1			
	Glidepath	0.55	0.00	0.94	1		
	Anthro NO_3	0.59	0.05	0.15	0.20	1	
	YELP NOx	0.12	0.00	0.27	0.23	0.01	1

Visibility and NOx Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*YELP NOx*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Billings NOx	0.79	-0.26	1			
	Glidepath	0.82	-0.29	0.97	1		
	Anthro NO_3	0.78	-0.11	0.79	0.84	1	
	YELP NOx	0.14	-0.21	0.52	0.48	0.38	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Billings NOx	0.62	0.07	1			
	Glidepath	0.68	0.08	0.93	1		
	Anthro NO_3	0.61	0.01	0.62	0.71	1	
	YELP NOx	0.02	0.04	0.27	0.23	0.14	1

Visibility and NOx Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings NOx*	*Glidepath*	*Anthro NO_3*	*YELP NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Billings NOx	0.76	0.58	1			
	Glidepath	0.79	0.62	0.96	1		
	Anthro NO_3	0.89	0.70	0.65	0.62	1	
	YELP NOx	0.42	0.19	0.52	0.48	0.52	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Billings NOx	0.58	0.34	1			
	Glidepath	0.62	0.38	0.92	1		
	Anthro NO_3	0.79	0.49	0.42	0.38	1	
	YELP NOx	0.18	0.04	0.27	0.23	0.27	1

Visibility and SO_2 Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*YELP SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO_2	0.77	-0.16	1			
	Glidepath	0.80	-0.11	0.95	1		
	Anthro SO_4	0.62	-0.25	0.74	0.83	1	
	YELP SO_2	0.11	0.06	0.13	0.10	-0.26	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings SO_2	0.59	0.03	1			
	Glidepath	0.64	0.01	0.90	1		
	Anthro SO_4	0.39	0.06	0.55	0.69	1	
	YELP SO_2	0.01	0.00	0.02	0.01	0.07	1

Visibility and SO_2 Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*YELP SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Billings SO_2	0.46	-0.23	1			
	Glidepath	0.48	-0.25	0.95	1		
	Anthro SO_4	0.47	-0.13	0.51	0.66	1	
	YELP SO_2	-0.28	0.07	0.13	0.10	0.09	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Billings SO_2	0.21	0.05	1			
	Glidepath	0.23	0.06	0.90	1		
	Anthro SO_4	0.22	0.02	0.26	0.44	1	
	YELP SO_2	0.08	0.00	0.02	0.01	0.01	1

Visibility and SO_2 Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*YELP SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO_2	0.70	0.04	1			
	Glidepath	0.74	0.07	0.95	1		
	Anthro SO_4	0.70	-0.08	0.41	0.51	1	
	YELP SO_2	0.03	-0.09	0.13	0.00	0.23	1

		Anthro dV	All dV	Billings SO_2	Glidepath	Anthro SO_4	YELP SO_2
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Billings SO_2	0.49	0.00	1			
	Glidepath	0.55	0.00	0.90	1		
	Anthro SO_4	0.49	0.01	0.17	0.26	1	
	YELP SO_2	0.00	0.01	0.02	0.00	0.05	1

Visibility and SO_2 Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*YELP SO_2*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Billings SO_2	0.81	-0.22	1			
	Glidepath	0.82	-0.29	0.95	1		
	Anthro SO_4	0.69	-0.37	0.77	0.90	1	
	YELP SO_2	-0.06	0.04	0.13	0.11	-0.07	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Billings SO_2	0.66	0.05	1			
	Glidepath	0.68	0.08	0.90	1		
	Anthro SO_4	0.48	0.14	0.59	0.81	1	
	YELP SO_2	0.00	0.00	0.02	0.01	0.00	1

Visibility and SO_2 Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*YELP SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Billings SO_2	0.72	0.55	1			
	Glidepath	0.79	0.62	0.95	1		
	Anthro SO_4	0.88	0.61	0.53	0.63	1	
	YELP SO_2	0.25	0.28	0.13	0.10	0.17	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Billings SO_2	0.52	0.30	1			
	Glidepath	0.62	0.38	0.90	1		
	Anthro SO_4	0.77	0.37	0.28	0.40	1	
	YELP SO_2	0.06	0.08	0.02	0.01	0.03	1

APPENDIX B: COST ANALYSIS

YELP
Nox Control Cost Summary

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFB with Selective Catalytic Reduction	80%	**$32,460,400**	**$4,153,623**	**323**	**81**	**$ 12,841.39**
CFB with Selective Non-Catalytic Reduction	50%	**$1,020,184**	**$597,303**	**202**	**202**	**$ 2,954.61**

Emissions (2014 - 2017) 404.32 **NO2 tpy**

YELP Nox Control Cost Analysis
SCR Cost Effectiveness Estimation Based on Contractor Estimates

Based on contractor estimates developed by Metso, Inc. and Harris Group, Inc. See attached report.

Cost Item	Cost: 2019 Inflation Adjustment[a]		Cost: 2011 Analysis		Reference
Total Capital Investment					
Metso estimate (two units)	$32,460,400		*$28,000,000*		Metso (Vendor Estimate)
Direct Annual Costs (two units)					
Ammonia System Maintenance =	$23,186		*$20,000*		Contractor Estimate
Soot Blower Maintenance =	$11,593		*$10,000*		Contractor Estimate
Additional Pressure Drop =	$156,095		*$134,646*		Contractor Estimate
ARC =	$243,307	/yr	*$209,874*	*/yr*	Reagent consumption cost
ACRC =	$518,555	/yr	*$447,300*	*/yr*	SCR catalyst, two boilers
	$438,215	/yr	*$378,000*	*/yr*	Catalyst install, two boilers
	$46,372	/yr	*$40,000*	*/yr*	SCR disposal, two boilers
DAC =	$1,437,323	/yr			Direct annual costs
Indirect Annual Costs					
CRF =	$i / (1 - (1 + i)^{-n})$				
i=	*5.5%*				
n=	*20*				
=	0.084				Capital recovery factor
	*CRF * TCI*				
IDAC =	$2,716,300	/yr			Indirect annual costs
Total Annual Costs					
TAC =	$4,153,623				Total annual cost
Tons of Nox, uncontrolled:					
Tons Nox emitted/year	*404.32*	tons			Average of 2014 - 2017 NOx tons as provided by MDEQ
NOx (lbs/hr):	92	lbs/hr			
Tons of Nox, controlled:					
η_{NOX} =	80%	Control efficiency			
NOx (lbs/hr):	18.46	lbs/hr			
Tons Nox emitted/year	80.9	tons			
Tons Nox reduced/year	323.46	tons			
Cost Effectiveness ($/ton)	**$ 12,841.39**				

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

YELP Nox Control Cost Analysis
SNCR Cost Effectiveness Estimation Based on Contractor Estimates

Based on contractor estimates developed by Metso, Inc. See attached report.

Also based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 1

Input Values			**Description**	**Reference**
Q_B =	525.0	MMBtu/hr	Heat input rate	Operation Data
η_{NOX} =	0.5	Control efficiency	SNCR Nox Control Efficiency	Bison Estimate
$NO_{X,IN}$ =	0.094	lb/MMBtu	Inlet NOx factor	Average of 2017 and 2018 EMR data
CF_{PLANT} =	0.92		Capacity factor of plant	Average of 2008 and 2009 Operations
CF_{SCR} =	1.0		Capacity factor of SNCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.06	\$/kWh	Cost of electricity	Bison Estimate
i =	5.5%		Interest rate, assumed	Bison Estimate
Design Values				
CF_{TOTAL} =	$CF_{PLANT} * CF_{SCR}$			Reference 1, Eqn 1.7
=	0.92		(Capacity Factor)	
NSR =	$[2 * NOx_{IN} + 0.7] \eta_{NOx} / NOx_{IN}$			Reference 1, Figure 1.8
=	3.00		(Normalized Stoichiometric Ratio)	
Power =	$0.47 * NOx_{IN} * NSR * Q_B / 9.5$			Reference 1, Eqn 1.23
=	7.32	kw	(Power Consumption Rate)	

SNCR Cost Effectiveness
Continued.

Cost Item	Cost: 2019 Inflation Adjustment[a]		Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Total Capital Investment				
Metso estimate	$1,020,184	Total capital investment	**$1,020,184**	*$880,000*
(adjusted for inflation)		*Contractor estimate*		
Direct Annual Costs (two units)				
Ammonia System Maintenance =	$34,779		**$34,779**	*$30,000*
(adjusted for inflation)				
ARC =	$470,024 /yr	Annual Reagent Cost	**$470,024 /yr**	*$405,438 /yr*
(adjusted for inflation)		*Contractor estimate*		
PWR =	$[0.47 * Q_B * NO_{X,IN} * NSR] / 9.5$			
=	14.6 kW	Power usage rate for both systems		
PC =	$PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$			
=	$7,100			
DAC =	$AMC + ARC + PC + AWC$			
	$511,903 /yr			
Indirect Annual Costs (two units)				
CRF =	$i / (1 - (1 + i)^{-n})$			
i=	*5.5%*			
n =	20.0			
CRF =	0.084	Capital recovery factor		
IDAC =	$CRF * TCI$			
=	$85,400 /yr	Indirect annual costs		

SNCR Cost Effectiveness
Continued.

Cost Item	Cost: 2019 Inflation Adjustment[a]			Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Total Annual Costs					
TAC =	*DAC + IDAC*				
TAC =	$597,303		Total annual cost		
Tons of Nox, uncontrolled:					
NOx (lbs/hr):	92	lbs/hr			
Tons Nox emitted/year	*404.32*	tons	Average of 2014 - 2017 NOx tons *as provided by MDEQ*		
Tons of Nox, controlled:					
η_{NOX} =	50%	Control efficiency			
NOx (lbs/hr):	46.16	lbs/hr			
Tons Nox emitted/year	202.2	tons			
Tons Nox reduced/year	202.2	tons			
Cost Effectiveness ($/ton)	**$ 2,954.61**				

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.
https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

YELP

SOx Cost Summary

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFB with Hydrated Ash Reinjection and Baghouses	50%	**$35,816,983**	**$5,796,240**	**866**	**866**	**$6,693**
CFB with Spray Dry Absorbers and Baghouses	80%	**$45,276,409**	**$7,509,313**	**1,386**	**346**	**$5,420**
CFB with DSI and Baghouses	50%	**$23,446,964**	**$5,062,421**	**866**	**866**	**$5,846**

Emissions (2014 - 2017) 1732.01 **SO2 (tpy)**

YELP

SO2 Cost Analysis

Cost for Hydrated Ash Reinjection

Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT COSTS			
Purchased equipment costs			
Number of hydrated ash systems required:		2	
Plant mW, per boiler (Gross)		32.5	
Cost per system + auxiliary equipment (Bison Estimate)[b]:		$ 4,018,906.67	*$3,466,667*
Total FDA + auxiliary equipment	A	$8,037,813.33	
Instrumentation	0.10 A	$803,781	
Sales taxes	0.03 A	$241,134.40	
Freight	0.05 A	$401,891	
Purchased equipment cost, PEC	B = 1.18 A	**$9,484,620**	
Direct installation costs			
Foundations & supports	0.12 B	$1,138,154	
Handling & erection	0.40 B	$3,793,848	
Electrical	0.01 B	$94,846	
Piping	0.30 B	$2,845,386	
Insulation for ductwork	0.01 B	$94,846	
Painting	0.01 B	$94,846	
Direct installation cost	0.85 B	**$8,061,927**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$10,480,504.81**	
Site preparation	As required, estimate	$ 28,982.50	*$25,000*
Buildings	As required, estimate	$ 57,965.00	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$20,052,072**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$948,462	
Construction and field expenses	0.10 B	$948,462	
Contractor fees	0.10 B	$948,462	
Start-up	0.01 B	$94,846	
Performance test	0.01 B	$94,846	
Contingencies	0.03 B	$284,539	
Total Indirect Cost, IC	0.35 B	**$3,319,617**	
Total Indirect Cost of Required Baghouse (see baghouse calcs):			
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$23,371,689**	

Cost for Hydrated Ash Reinjection Continued.

Cost Item				Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift	30.00 $/hr	$18,781	*$16,200*
Supervisor		15% of operator		$2,817	*$2,430*
Operating Materials	**Utilizes Recycled Lime in Ash**			-	
Maintenance					
Labor		0.5 hrs/shift	30.00 $/hr	$18,781	*$16,200*
Material		100% of maint. labor		$18,781	*$16,200*
Utilities					
Power Consumption:	**1.00% Bison Estimate**	(% of Electrical Generation)			
Electricity	5,694,000 (kWh/yr)				
Rate:	$0.06 $/kWh			$396,063	*$341,640*
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$35,495	
Administrative Charges		2% of TCI		$467,434	
Property Taxes		1% of TCI		$233,717	
Insurance		1% of TCI		$233,717	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)				$1,955,727	
			TOTAL ANNUAL COST (HAR)	**$3,381,313**	
			TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$2,414,927**	
			TOTAL ANNUAL COST FROM BAGHOUSE(S) AND HAR:	**$5,796,240**	
		Uncontrolled Emissions (tons/yr):		1732.01	
		Control Efficiency:		50.00%	
		Controlled Emissions (tons/yr):		866.0	
		Tons Removed (tons/yr):		866.0	
		Cost-Effectiveness ($/ton):		**$6,693**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

b) Capital cost scaled based on estimate from a vendor of $8M for a 75 MW plant.

Capital Recovery Factor $$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n =	20	years
i =	5.50%	interest rate
CR =	0.0837	

YELP

SO2 Cost Analysis

Costs for Spray Dry Absorber

Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	Cost: 2011 Analysis
DIRECT COSTS			
Purchased equipment costs			
Number of SDA systems required:		2	
Plant mW, per boiler (Gross)		32.5	
SDA Cost per kW:[b]		$ 150	
Cost per system + auxiliary equipment:		$ 5,651,587.50	*$4,875,000*
Total FDA + auxiliary equipment	A	$11,303,175	
Instrumentation	0.10 A	$1,130,318	
Sales taxes	0.03 A	$339,095.25	
Freight	0.05 A	$565,159	
Purchased equipment cost, PEC	B = 1.18 A	**$13,337,747**	
Direct installation costs			
Foundations & supports	0.12 B	$1,600,530	
Handling & erection	0.40 B	$5,335,099	
Electrical	0.01 B	$133,377	
Piping	0.30 B	$4,001,324	
Insulation for ductwork	0.01 B	$133,377	
Painting	0.01 B	$133,377	
Direct installation cost	0.85 B	**$11,337,085**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$14,738,210**	
Site preparation	As required, estimate	$ 28,982.50	*$25,000*
Buildings	As required, estimate	$ 57,965.00	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$28,162,904**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$1,333,775	
Construction and field expenses	0.10 B	$1,333,775	
Contractor fees	0.10 B	$1,333,775	
Start-up	0.01 B	$133,377	
Performance test	0.01 B	$133,377	
Contingencies	0.03 B	$400,132	
Total Indirect Cost, IC	0.35 B	**$4,668,211**	
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$32,831,115**	

Costs for Spray Dry Absorber Continued.

Cost Item				Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift	30.00 $/hr	$18,781	*$16,200*
Supervisor	15%	of operator		$2,817	*$2,430*
Operating Materials				-	
SOx to be controlled (tons)			1732.01		
Ratio of sorbent to SOx[c]			1.4		
Lime required:	2122.75	tons/year			
lime cost ($/ton):	$100	estimate			
lime cost ($/year):				$246,091	*$212,275*
Maintenance					
Labor	0.5	hrs/shift	30.00 $/hr	$18,781	*$16,200*
Material	100%	of maint. labor		$18,781	*$16,200*
Utilities					
Power Consumption[d]:	1.75%	(% of Electrical Generation)			
Electricity	9,964,500	(kWh/yr)			
Rate:	$0.06	$/kWh		$693,111	*$597,870*
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$35,495	
Administrative Charges			2% of TCI	$656,622	
Property Taxes			1% of TCI	$328,311	
Insurance			1% of TCI	$328,311	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)				$2,747,286	
			TOTAL ANNUAL COST (SDA):	**$5,094,386**	
			TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$2,414,927**	
			TOTAL ANNUAL COST FROM BAGHOUSE(S) AND SDA:	**$7,509,313**	
		Uncontrolled Emissions (tons/yr):		1732.01	
		Control Efficiency:		80.00%	
		Controlled Emissions (tons/yr):		346.4	
		Tons Removed (tons/yr):		1,385.6	
			Cost-Effectiveness ($/ton):	**$5,420**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.

February 2011 =	$ 100.00
August 2019 =	$ 115.93
Ratio (2019/2011) =	1.1593

b) Lowest Capital Cost in $/kW from EPA Air Pollution Control Fact Sheet for FGD, Dry Systems <200 MW: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

c) Source: Air Pollution Engineering Manual, 2nd Edition, p265

d) Median of values, Source: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 20 years

i = 5.50% interest rate

CR = 0.0837

YELP
SO2 Cost Analysis
Costs for Dry Sorbent Injection
Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT COSTS			
Purchased equipment costs			
Number of hydrated ash systems required:		2	
Plant mW, per boiler (Gross)		32.5	
Cost per system + auxiliary equipment:[b]		$1,883,863	*$1,625,000*
Total FDA + auxiliary equipment	A	$3,767,725	
Instrumentation	0.10 A	$376,773	
Sales taxes	0.03 A	$113,031.75	
Freight	0.05 A	$188,386	
Purchased equipment cost, PEC	B = 1.18 A	**$4,445,916**	
Direct installation costs			
Foundations & supports	0.12 B	$533,510	
Handling & erection	0.40 B	$1,778,366	
Electrical	0.01 B	$44,459	
Piping	0.30 B	$1,333,775	
Insulation for ductwork	0.01 B	$44,459	
Painting	0.01 B	$44,459	
Direct installation cost	0.85 B	**$3,779,028**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$4,912,737**	
Site preparation	As required, estimate	$28,983	*$25,000*
Buildings	As required, estimate	$57,965	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$9,445,600**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$444,592	
Construction and field expenses	0.10 B	$444,592	
Contractor fees	0.10 B	$444,592	
Start-up	0.01 B	$44,459	
Performance test	0.01 B	$44,459	
Contingencies	0.03 B	$133,377	
Total Indirect Cost, IC	0.35 B	**$1,556,070**	
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$11,001,670**	

Costs for Dry Sorbent Injection
Continued.

Cost Item					Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS						
Operating Labor						
Operator	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Supervisor	15%	of operator			$2,817	*$2,430*
Operating Materials					-	
SOx to be controlled (tons)	1732.01					
Ratio of sorbent to SOx[c]:	3					
Lime required:	4548.76	tons/year				
lime cost ($/ton):	$100	estimate				
lime cost ($/year):					$527,337	*$454,876*
Maintenance						
Labor	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Material	100%	of maint. labor			$18,781	*$16,200*
Utilities						
Power Consumption[d]:	0.30%	(% of Electrical Generation)				
Electricity	1,708,200	(kWh/yr)				
Rate:	$0.06	$/kWh			$118,819	*$102,492*
INDIRECT ANNUAL COSTS, IC						
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$35,495	
Administrative Charges			2%	of TCI	$220,033	
Property Taxes			1%	of TCI	$110,017	
Insurance			1%	of TCI	$110,017	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)					$920,612	
				TOTAL ANNUAL COST (DSI):	**$2,101,490**	
				TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$2,960,931**	
				TOTAL ANNUAL COST FROM DSI AND BAGHOUSE(S):	**$5,062,421**	
				Uncontrolled Emissions (tons/yr):	1732.01	
				Control Efficiency:	50.00%	
				Controlled Emissions (tons/yr):	866.0	
				Tons Removed (tons/yr):	866.0	
				Cost-Effectiveness ($/ton):	**$5,846**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

b) Dry Sorbent Injection Systems can cost ~$40 - $50/kW: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

c) Source: Air Pollution Engineering Manual, 2nd Edition, p264

d) Median of values, Source: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n =	20	years
i =	5.50%	interest rate
CR =	0.0837	

YELP
Replacement of Baghouses for SOx Controls

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998)

By these calculations from Chapter 5 of Manual

Stack Flowrate [a]	233,542	ACFM
Stack Flowrate [a]	116,771	dscfm
Operating Hours	8,760	hrs/yr
Pressure Drop:		
Baghouse (mean from Section 5.2.2):	7.5	in. of H_20

Baghouse Electricity Costs:	0.00181(Q)(delta P)(hours per year)	
Power (kWh/yr)=	2,777,215	kWh/yr
Cost per kWh=	$0.060	Bison Estimate
Cost of Electricity=	$166,633	

Compressed Air Costs:	
flow needed (2 scfm/1,000 acfm)	2
cost (per 1,000 scfm)[b]	0.36
cost per min	$0.17
cost per hour	$10.01
cost per year	$87,673.95

Cost of Bags (based on vendor estimate for similar project)	**Cost: 2019 Inflation Adjustment[c]**	***Cost: 2011 Analysis***
Fiberglass Bags	$231,860	*$200,000*

Notes:

a) 2009 Stack Test Data

b) Scaled per the Chemical Engineering Plant Cost Index (1998 & 2010)

Annual avg	CEPCI98 =	389.5
Annual avg (proposed)	CEPCI10 =	556.4

c) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.
https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

YELP
Replacement of Baghouse for SOx Controls
Total Capital Costs for Fabric Filter Baghouse with Fiberglass Bags

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998) and associated CO$T-AIR spreadsheet

Cost Component	Equation	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Direct Costs			
Purchased Equipment Costs			
Baghouses Needed		2	
Capital Cost per scfm:[b]		$ 16	
SCFM:		116,771	
Cost per Baghouse (estimate):		$ 2,165,964.69	*$ 1,868,338*
Total Equipment Costs	Sum=A	$4,331,929	
Instrumentation	0.1A	$433,193	
Equipment Tax:	0.03A	$129,958	
Freight	0.05A	$216,596	
Purchased Equipment Cost	Sum=B	$5,111,677	
Direct Installation Costs			
Foundation and Supports	0.04B	$204,467	
Handling and Erection	0.5B	$2,555,838	
Electrical	0.08B	$408,934	
Piping	0.01B	$51,117	
Insulation for Ductwork	0.07B	$357,817	
Painting	0.04B	$204,467	
Direct Installation Costs	0.74B	$3,782,641	
Retrofit Factor:	1.3		
Direct Installation Costs Including Retrofit Factor		$4,917,433	
Site Preparation		$ 115,930	*$ 100,000*
Facilities and Buildings		Not Calculated	
Total Direct Costs	1.74B + Retrofit	**$10,145,040**	
Indirect Costs			
Engineering	0.1B	$511,168	
Construction and Field Expenses	0.2B	$1,022,335	
Contractor Fees	0.1B	$511,168	
Start-up	0.01B	$51,117	
Performance Test	0.01B	$51,117	
Contingencies	0.03B	$153,350	
Total Indirect Costs	0.45B	**$2,300,255**	
Total Capital Investment	2.19B	**$12,445,294**	

Total Capital Costs for Fabric Filter Baghouse with Fiberglass Bags Continued.
Total Annual Costs

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998)

Cost Component		Equation		Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Direct Annual Costs					
Operating Labor					
	Operator	2 hr/shift x 3 shifts/day x 365 days/yr x $30.00/hr	$	76,166	*$65,700*
	Supervisor	15% of operator	$	11,425	*$9,855*
Operating Materials					
Maintenance					
	Labor	1 hr/shift x 3 shifts/day x 365 days/yr x $30.00/hr	$	38,083	*$32,850*
	Materials	100% of Maintenance Labor	$	38,083	*$32,850*
	Replacement Bags	(Future worth at 3 years and 10%=0.4021*cost of bags)	$	216,165	*$186,462*
Utilities					
	Electricity	0.000181(Q, acfm)(dP, in. H2O)(hr/yr)*$40.00/MWh/yr)		$222,177	
	Compressed Air	2 scfm/1,000acfm(Q)($0.25/1,000scfm)(60min/hr)(hrs/yr)		$175,348	
	Total DC			**$777,447**	
Indirect Annual Costs					
Overhead		60% of sum of Operating Labor and Operating Materials		$98,254	
Administrative Charges		2% of Total Capital Investment		$248,906	
Property Tax		1% of Total Capital Investment		$124,453	
Insurance		1% of Total Capital Investment		$124,453	
Capital Recovery (from TCI spreadsheet)		at 5.5% for 20 years (CRF x Total Capital Investment)		$1,041,414	
	Total IC			**$1,637,480**	
Total Annual Cost ($)		Sum of Total DC and Total IC		**$2,414,927**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

b) Median Value from Air Pollution Control Technology Factsheet, Fabric Filters.http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf

Capital Recovery Factor

n =	20	years
i =	5.50%	interest rate
CR =	0.0837	

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

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ECONOMIC EVALUATION OF NOX CONTROL

Yellowstone Energy Limited Partnership

Billings, Montana

METSO REFERENCE No. 710068

Feb 2011

metso
Expect results

Executive Summary

Metso was contracted to provide an economic evaluation of NOx control for the two Circulating Fluidized Bed Boilers (CFB) at the Yellowstone Energy Limited Partnership (YELP) facility in Billings, Montana. This estimate was compiled using drawings of the plant that are in Metso's archives. The drawings do not show balance of plant piping, cable trays, small bore piping, and modifications that have been made to the facility following initial installation. There could be interferences and significant unknowns that would alter Metso's conclusions contained within this report. This is an order of magnitude estimate.

Metso evaluated the use of Selective Catalytic Reduction (SCR) and Selective Noncatalytic Reduction (SNCR) technology to reduce NOx emissions at the YELP facility. A SNCR is capable of reducing NOx emissions by at least 50% while the SCR is capable of practical reductions of up to 80%, depending on space availability.

The total cost for installing SCRs on both units ranges from $22,000,000 to $28,000,000 whereas the total installed cost for SNCRs would be less than $1,000,000 for both units combined. Since the bulk of the SNCR system will be shared by two units, SCR technology will be between 22 and 32 times the cost for SNCR technology at the facility. The Operation and Maintenance (O&M) costs for the SCR are estimated to be 2.8 times the costs for O&M of the SNCR system. The increased cost for the potential 30% additional reduction in NOx emissions by the installation of an SCR system at this facility is significant.

CFBs are typically inherently lower NOx generators than other boiler types. Petroleum coke fired CFBs emit fewer NOx emissions than those firing coal or other fuels. SNCRs are on many of the boilers that Metso has supplied within the United States. However, none of the Metso-supplied CFB boilers within the United States incorporate SCR technology.

There are risks associated with using an SCR on a boiler utilizing petroleum coke as a fuel source. There is vanadium in petroleum coke. It is proven that vanadium poisons SCR catalysts. The catalyst life for this unit is likely to be short (likely months instead of years). This will likely reduce the availability of this unit and subject the facility to significant operating and maintenance costs. The catalyst life is difficult to quantify without a further extensive study by a catalyst supplier. It is unlikely or would be costly to obtain a lengthy catalyst life guarantee from a catalyst supplier for this application.

Fouling of petcoke fired units occurs on superheater surfaces. The superheater is upstream of this SCR. The fouling will likely cause plugging and blinding of the SCR catalyst when it breaks loose from the superheater surfaces. This will increase maintenance costs at this facility and subject the unit to increased downtime.

Metso would be hesitant to install an SCR on a petroleum coke fired boiler.

TABLE OF CONTENTS

Overview –

There are two Circulating Fluidized Bed Boilers at the YELP facility. Each boiler is rated for 300,000 lb/hr at 1300 psig and 955F main steam. The fuel is petroleum coke and coker gas.

The purpose of this assessment is to provide estimated capital and O&M costs for NOx control solutions.

- The average uncontrolled NOx for Yellowstone (YELP) is .15 lb/MMBTU.

The following solutions were evaluated

- An SNCR system capable of 50% NOx reduction for controlled NOx rates of .075 lb/MMBTU
- An SCR system capable of 80+% reduction for controlled NOx rates of .03 lb/MMBTU.

Both solutions require a method for the storage and supply of ammonia to the process. An aqueous ammonia system was selected for the evaluation.

Aqueous ammonia system

SYSTEM DESCRIPTION:

The ammonia system is similar for both the SNCR and the SCR.

There are two boilers at this facility however a common ammonia system can be used to supply reagent to both units. It is less expensive and more practical to have one larger system than two small systems.

The system consists of a 14,000 gal ammonia tank with metering pumps, filters, tank level sensor and alarm, caged ladder for access to top of tank, and other various attachments. The tank can contain approximately 8.5 days of storage of 19.5% aqueous ammonia using the SNCR system while providing 50% reduction of NOx when both boilers are at full load. The larger tank will allow more flexibility in the filling cycle. The tank is sized to contain slightly more than 2 standard tank truck loads of aqueous ammonia.

LOCATION AND INSTALLATION CONSIDERATIONS OF AMMONIA SYSTEM

The tank and forwarding skid would be located on the ground, outside of the boiler house. A containment dike is installed around the tank to capture the fluid if a leak or rupture occurs.

Selective noncatalytic reduction system (SNCR)

SYSTEM DESCRIPTION:

An SNCR system for a CFB consists of the aqueous ammonia system listed above, small bore piping from the metering skid to the boilers, and injection nozzles at the cyclone inlets for the boilers.

There are two boilers at this facility. A single line will be routed from the forwarding system to the elevation of the cyclone inlet ducts of the two boilers. The line will branch into two lines at this elevation. Each branch line will have a control valve that will meter the required flow to the specific boiler. The line downstream of each control valve will branch again to feed two distribution or metering panels. A distribution panel will be located at each of two cyclone inlet ducts on each boiler. The metering skids will be used to bias ammonia flow to each of the four nozzles on each cyclone inlet duct.

Steam or compressed air is used to atomize and distribute the ammonia into the cyclone inlet ducts. If the system is to be used intermittently, purge air would be installed to keep the nozzles clear of material when the system is not in use.

LOCATION AND INSTALLATION CONSIDERATIONS

The distribution panels and injection nozzles are located near the cyclone inlet ducts. The injection nozzles penetrate and mount to the cyclone inlet ducts. The nozzles are used to inject ammonia into the duct, while distributing the ammonia across as much as the duct as practical. This location provides an area of high velocity and narrow duct width to allow for good penetration and mixing of the ammonia with the flue gas. The ammonia is sprayed upstream of the cyclones on the CFB. The cyclones promote further mixing of the ammonia and the flue gas because of flue gas cyclonic action, direction change, and mixing. Higher reduction rates are achievable on CFBs than for BFBs, and other boiler types because of this optimum spray location and cyclonic mixing. While it may be possible to capture more NOx on a CFB, the standard guaranteed reduction rates are in the 50% range in order to limit slip to 10 ppm.

TIME FOR COMPLIANCE

An SNCR system could be installed within 16-24 weeks. A maximum 2 week outage would be required to make tie-ins.

CAPITAL COSTS AND DOWNTIME

There are two boilers at YELP. A common ammonia system tank and delivery system will be utilized for both boilers. The ammonia tank and forwarding system is the bulk of the cost for supply and installation. The rest of the system consists of supply and installation of small bore piping, distribution skids, and injection nozzles. The majority of the piping is installed for the SNCR for the first unit. The pipe for the second unit branches off at the upper elevation for distribution of ammonia to the second unit. There is a minimal incremental cost for the equipment and installation of SNCR technology for the second unit because of this. The incremental cost is limited to installation of some small bore piping, a control valve, two additional distribution panels, tubing, and nozzles into the cyclones. The installed estimate for the SNCR system is $880,000. This is the installed cost for SNCR technology for NOx control for both units. Control technologies are often evaluated based on $/kw basis. The gross electrical generation for each boiler is 32.5 MW. The estimated cost for SNCR capital costs (supply and installation) is $14/kw.

The tie- in can be made during the normal annual outage. The majority of the system can be installed with boilers on-line. The nozzles would be installed during the annual outage.

OPERATING AND MAINTENANCE CONSIDERATIONS

The O&M costs are estimated to be approximately $220,000 per unit. Most of this is the cost of the ammonia. Ammonia consumption is $203,000 per unit based on $196/delivered ton. Maintenance of the ammonia system and nozzles should average $10,000-15,000 for each unit.

OTHER NON-ENVIRONMENTAL IMPACTS

SNCRs are the primary method of NOx control on the majority of CFBs and no problems have been noted. Metso has not observed nor is aware of any increased fouling, decreased pressure part life, or other issues associated with the use of SNCRs.

Selective catalytic reduction system (SCR)

SYSTEM DESCRIPTION:

An SCR is an array of catalyst installed in an existing duct or in a dedicated enclosure. Ammonia is injected upstream of the catalyst. The catalyst enhances the reaction rate between the ammonia and the NOx, thus high capture efficiencies can be attained.

The temperature range for proper operation of an SCR is between 480F to 800F. The optimum operation of an SCR depends on straight, uniform, and optimum flue gas velocities across the catalyst grid. When optimum conditions exist, SCRs are often capable of up to 90% reduction of NOx in low dust flue gas streams. For practical retrofits, especially on smaller units, optimum conditions do not exist without significant capital modifications.

Installation of an SCR in a low dust flue gas streams is often not practical, especially on an existing boiler. The reason is that the low dust portion of a flue gas stream is located after a baghouse or a precipitator. The temperature of the flue gas stream is too low in these areas for proper operation of an SCR. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400F. This is still too low for the operation of an SCR. Therefore, on some installations, a regenerative SCR is installed. Regenerative SCRs are expensive to install and expensive to operate because an RSCR requires the use of burners to heat up the flue gas stream in order for the NOx capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, Metso did not evaluate the use of an RSCR.

Metso evaluated the use of a high dust SCR for this installation based on the above information.

A vaporizer in the ammonia delivery system is required for an SCR to inject the ammonia in gaseous form.

LOCATION AND INSTALLATION CONSIDERATIONS

The temperature range for proper operation of an SCR is between 480F to 800F. As can be seen from the general arrangements drawings there are two locations that could be utilized for the current configuration. Neither of these two locations have flue gas temperatures in the range listed above. One possible solution is presented. However, the solution will be costly to implement and is not an ideal location for an SCR. Metso believes that a maximum NOx reduction rate of 80% would be the recommended target for an SCR at this facility. CFD modeling and physical modeling, as well as a detailed assessment of catalyst life would need to be performed before any guarantees could be presented. An assumption of 80% NOx reduction was used as a basis for capital and O&M costs.

The two available locations considered were:

1. Upstream of economizer
2. Between the economizer and the baghouse.

Upstream of the economizer –

The temperature upstream of the economizer is between 800-880F. This is too high for the proper operation of an SCR.

Between economizer and baghouse –

The temperature downstream of the economizer is 350F, which is too low for effective operation of an SCR.

Possible Solution

One possible option is to split the economizer since it is constructed in two assemblies with a jumper pipe between the two. The predicted temperature in this area is in the range of 550F. The lower bank of the economizer and the ash hopper could be lowered down approximately 25 ft. This would allow for the installation of 2 levels of catalyst within the duct with a spray grid array above the catalysts.

The practical limit for SCRs in high dust, in-duct installations, approaches 80%. To meet this level of reduction for each of these units would require two layers of catalyst. While not completely investigated, it may be possible, but will be challenging to install two layers of catalyst in this location. Obtaining evenly distributed flue gas at optimum velocities in this area is the challenge.

TIME FOR COMPLIANCE

The normal lead time for an SCR is 16-24 months, with an additional 2 months to make the necessary modifications and tie-ins.

CAPITAL COSTS AND DOWNTIME

The engineering and supply estimate for the SCR is $4,000,000-5,000,000 for each boiler.

The area where modifications are required is quite congested. There is uncertainty in the installation estimate due to significant mechanical modifications required at the site. Rigging, ductwork modifications, and installation of the SCR will be a challenge. The Harris Group Inc. has estimated the installation costs to range between $6,100,000 and $9,100,000 for each SCR.

The total installed estimated for an SCR solution for each unit is between $11,000,000 and $14,000,000. This equates to a range of $338/kw (gross electric) and $431/kw (gross electric) per unit. The estimated gross electrical generation is 32.5 MW per boiler. The total installed cost for two SCRs, one for each unit, is between $22,000,000 and $28,000,000. There would be minimal savings realized from duplicate units, since the majority of the cost is equipment costs and installation costs.

Significant mechanical modifications will be required. A 2-3 month outage would be required to make the necessary modifications and tie-ins. <u>The cost of lost generation has not been estimated</u> since Metso does not know the load profile and power sales rate structure.

OPERATING AND MAINTENANCE CONSIDERATIONS

(O&M costs are for each unit, there are two units at YELP – multiply by two for plant yearly costs)

The O&M costs are expected to be approximately $620,000 per unit for the SCR when catalyst costs and installation are factored in. Catalyst Maintenance costs for the SCR are expected to annually average $430,000 for each unit. These estimates are based on typical catalyst life. The costs are likely low because of the higher potential for catalyst poisoning resulting from the presence of vanadium in the flue gas stream. Vanadium has been shown to poison catalysts. Catalyst poisoning would cause difficulty in maintaining compliance. Unit availability and revenues will likely decrease because of catalyst maintenance events. It is recommended that a detailed review of tube fouling and catalyst fouling potential be performed prior to selecting SCR technology as a method of NOx control on this unit.

Maintenance of the SCR and catalyst will also be difficult due to limited working area. The performance and the reliability of the SCR could be compromised for various reasons including limited straight duct above the SCR. Ideally, an SCR should have additional space available for the future addition of another layer of catalyst. Because of limited available room, only two layers of catalyst can be installed. There is not enough room for the future addition of the third layer of catalyst. This additional expansion slot (third layer) would provide more performance flexibility as well as reduce the outage time for catalyst replacement. In most installations, new catalyst can be installed in the third row while the exhausted catalyst is being removed from one of the two in-service rows. In this installation, it is likely that one row of catalyst will have to be removed completely and then fresh catalyst will be installed in its place. This will cause more unit downtime, which translates into less availability and a decrease in revenue.

Petroleum fired coke units often have fouling that occurs on superheater surfaces upstream of where this SCR is to be located. It has been shown on other petroleum coke fired units that the debris from fouled tubes have broken loose and plugged up airheater tubes downstream of the superheaters. It is likely that deposits on superheaters, which are known to exist at YELP will break loose and foul an SCR downstream of this superheater bundles. This could significantly increase the maintenance costs for the SCR.

An SCR also introduces additional pressure drop in the system. A 4” pressure drop translates into $70,000 per year at $.06/kw. This is a per unit cost.

The ammonia usage is less for an SCR than an SNCR. The predicted ammonia consumption will add $105,000 to the operating costs for each boiler.

OTHER NON-ENVIRONMENTAL IMPACTS

SCRs can contribute to airheater fouling due to ammonia bisulfate formation. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion.

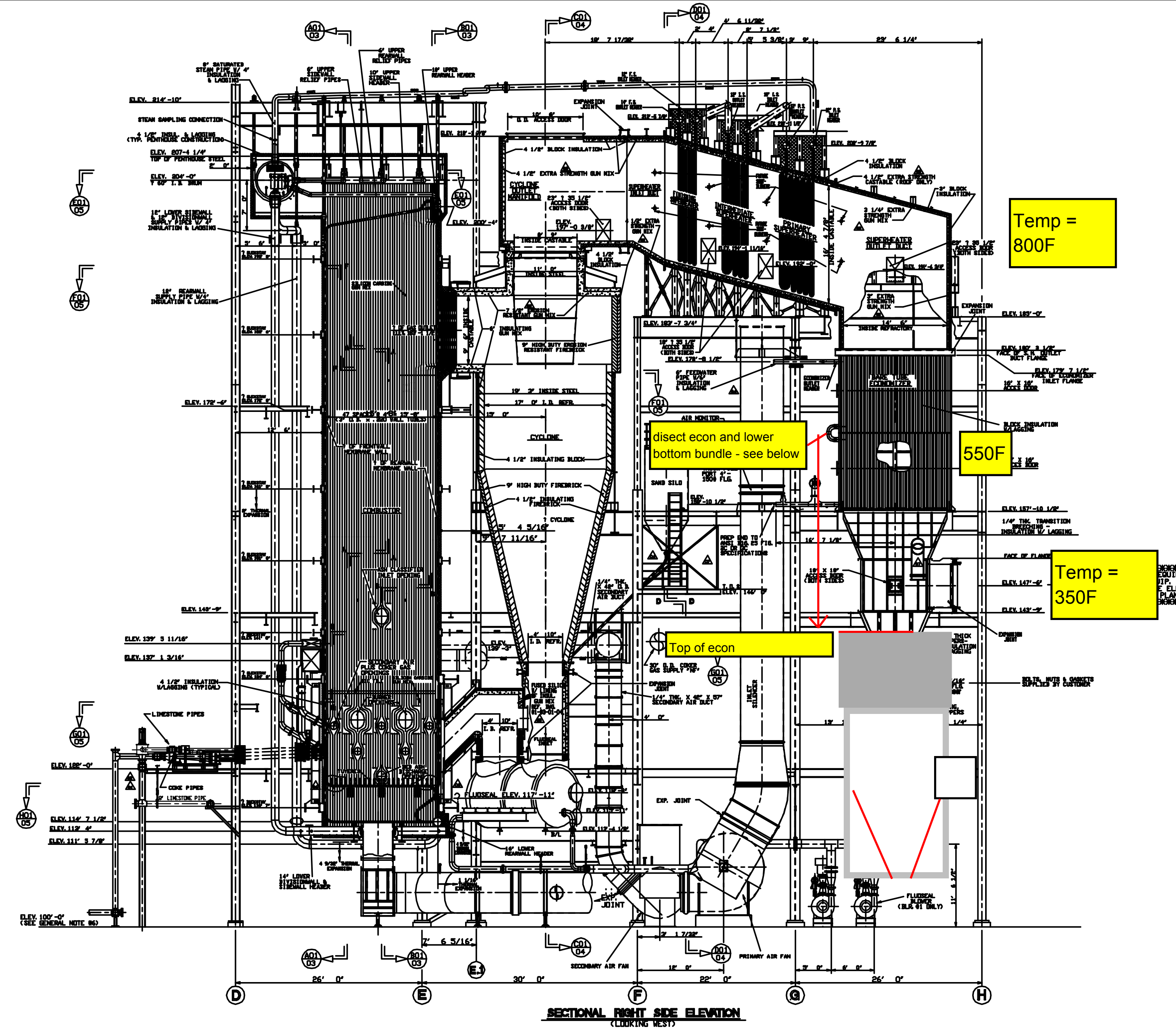
On some installations, catalyst life is very short and SCRs have fouled in high dust environments. This had led to downtime on other units within the fleet in overseas installations. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor. The presence of vanadium in the fuel has led to reduced catalyst life on prior units.

In summary, Metso does not believe that SCR technology would be the most practical solution for NOx reduction at this facility because of the many likely operating and maintenance issues presented above. SNCR technology is proven and is capable of at least 50% reduction of NOx emissions.

TABLE 1: Summary Table of Assessment of NOx Control Economic Evaluation

				Yellowstone Billings		
				capital and install for SNCR is for both units	SCR Cost Range (each boiler)	
				SNCR(50%)	**SCR(~80%)**	**SCR(~80%)**
Cost of compliance	Eng and Supply			$ 685,000	$ 5,500,000	$ 5,500,000
	Installation			$ 195,000	$ 5,500,000	$ 8,500,000
	Total installed costs			**$ 880,000**	**$ 11,000,000**	**$ 14,000,000**
				SNCR cost above for both units combined	**SCR Costs are for each of the two units**	
				All costs below are per unit		
	Other Capital Costs	ID fan upgrade			may need to upgrade ID fan (estimate include in above)	
	O&M(avg yearly) for each unit - **subtotal of costs below**		$/yr	**$ 217,719**	**$ 619,910**	
		Ammonia sys maint	$/yr	$ 15,000	$ 10,000	
		sootblower	$/yr		$ 5,000	
		SCR catalyst	$/yr		$ 223,650	
		Catalyst install	$/yr		$ 189,000	
		SCR disposal	$/yr		$ 20,000	
		additional pressure drop	$/yr		$ 67,323	
		Ammonia cost (each unit)	$/yr	$ 202,719	$ 104,937	
Time necessary for compliance	supply and install			24-30 wks	26 months	
Energy and non-air quality environmental impacts of compliance	unit downtime, loss of revenue			2 week outage	lost revenue for 2 month outage	
	ash resale problems			none observed	unknown	
	fouling			not expected	airheater fouling	
Remaining useful life of affected source				24	24	

SCR Installation order of magnitude estimates by Harris Group Inc.



SECTIONAL RIGHT SIDE ELEVATION
(LOOKING WEST)

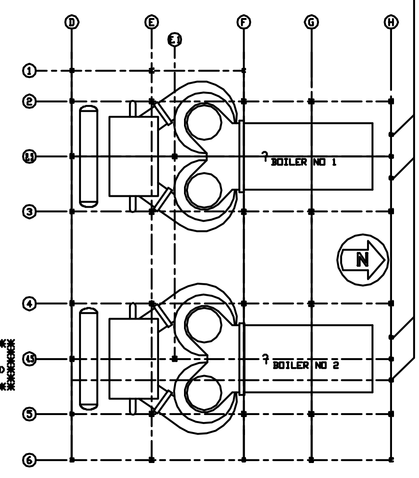
DESIGN DATA

1. STEAM CAPACITY-CONTINUOUS........................300,000#/HR.
2. DESIGN PRESSURE........................1575 PSIG.
3. OPERATING PRESSURE AT STEAM OUTLET(S.H. HEADER).....1300 PSIG.
4. STEAM TEMPERATURE(AT NON-RETURN VALVE OUTLET).......955°F. (513°C)
5. FEEDWATER TEMPERATURE AT ECONOMIZER INLET...........250°F.
6. COMBUSTOR VOLUME(INCLUDING DENSE BED)...............31,800 FT³
7. TYPE OF FIRING........................CIRCULATING FLUIDIZED BED
   START-UP BURNER........................NO. 2 OIL
8. ECONOMIZER DESIGN PRESSURE(TUBE SIDE)...............1650 PSIG.

HEATING SURFACE

1. COMBUSTOR-FLAT PROJECTED........................8,837 FT²
2. SUPERHEATER (TOTAL)........................15,534 FT²
   A. PRIMARY.............6,803 FT²
   B. INTERMEDIATE.......5,103 FT²
   C. FINISHING..........3,628 FT²
3. ECONOMIZER........................36,687 FT²

BETWEEN ELEV. 143'-9" & 157'-10 1/2" ONLY



KEY PLAN VIEW
(1/16"=1'-0")

GENERAL NOTES

1. FOR ADDITIONAL GENERAL ARRANGEMENT VIEWS & SECTIONS, REFER TO DRAWINGS NO. 01-03-01-02, 01-03-01-03, 01-03-01-04, 01-03-01-05, 01-20-01-01, & 01-20-01-02.
2. FOR PRESSURE PART ARRANGEMENT DETAILS, REFER TO DRAWINGS 01-05-01-01 THRU 01-05-01-06.
3. 'N/F' DENOTES NOT FURNISHED BY TAMPELLA POWER CORP.
4. FOUNDATION & FOUNDATION WORK N/F.
5. FOR PLOT PLAN, REFER TO DRAWING NO. 01-08-01-01.
6. DATUM ELEVATION 100'-0" IS EQUIVALENT TO 3116'-6" ABOVE SEA LEVEL.
7. INSULATION, LAGGING, & REFRACTORY BY TAMPELLA POWER.
8. INSULATION & LAGGING THICKNESS ARE SHOWN FOR REFERENCE ONLY.
9. STRUCTURAL STEEL SHOWN ON THIS DRAWING IS FOR CONCEPTUAL USE ONLY.

REV.	REVISIONS	DATE	BY	CK'D	REV.	REVISIONS	DATE	BY	CK'D
						REVISED REFRACTORY CALLOUTS	5-12-94	ADS	KES
						ADDED P.A. FAN INLET DUCT, SAND BIN & REV. LINE & COKE PIPES	4-11-94	MLW	KES
	ADDED AIR INLET TO ECON. HOPPER	2/06/96	KES	JFL		GENERAL REVISIONS	3-2-94	WPW	KES
	ADDED ACCESS PLATFORM @ ELEV. 146' 0"	2/06/96	KES	JFL		GENERAL REVISIONS	1-24-94	SAM	CRP
	REMOVED REFRACTORY @ FLOOR; MOVED SAND FILL PIPE	7-14-94	MLW	KES		GENERAL REVISIONS	1-7-94	SAM	CRP

PROJECT
BGI FLUID
PETROLEUM COKE PROJ.
2-300,000 #/HR.
TYPE 'HCFS' BOILER

THIS DRAWING IS THE PROPERTY OF
Tampella Power
WILLIAMSPORT • PENNSYLVANIA

DRAWN BY	DATE	SCALE
BTS	1-20-92	3/16" = 1'-0"
CHECKED BY	DATE	MADE FROM
CRP	11 24 93	01-03-01-01 FROM 17337
APPROVED BY		Y [X] N [ ] Y [ ] N [X]

GENERAL ARRANGEMENT-
SECTIONAL SIDE
ELEVATION

17434 01-03-01-01 DRAWING NO. 07 REV.

CADAM DRAWING
DO NOT REVISE MANUALLY

February 21, 2011

Mr. Scott Siddoway
Rosebud Operating Services, Inc.
1087 W. River Street, Suite 200
Boise, ID 83702

Via E-mail: scott.siddoway@rosi-boise.com

Reference: Montana Power Plants
Review of Economic Evaluation of NO_x Control at YELP and CELP
Harris Group Inc. Project No. 65353

Dear Scott,

Harris Group Inc. (HGI) has reviewed two reports prepared by Metso titled "Economic Evaluation of NO_x Control; Colstrip Energy Limited Partnership" and "Economic Evaluation of NO_x Control; Yellowstone Energy Limited Partnership" per your request. The reports are based on a general review of the two most common technologies for NO_x control in power boilers: Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) with a brief presentation on how to implement each technology in each boiler. The reports present rough order of magnitude equipment costs, installation costs, and operating and maintenance costs for each technology.

The total installed cost for SNCR ($880,000) is in the expected range compared to similar installations that we are familiar with. Operating costs are by far the greatest expense with the cost of the reagent being about 93% of annual operating cost. Metso's estimate of annual operating cost appears to be in the right range. However, the reagent cost is directly affected by the cost of natural gas and will have a tendency to fluctuate quickly when natural gas prices change. The application of SNCR on circulating fluid bed boilers (CFB) is wide spread today as an effective technology for NO_x control; however, the technology is limited to about 50% removal.

The installed costs for SCR appear to be on the low side considering the degree of difficulty associated with the installation on the boilers at these two facilities. The space inside the boiler buildings around the economizers is very limited and working space outside the building at YELP is extremely limited. This makes the engineering design and installation for a retrofit project considerably more difficult than a new installation of the same size and removal efficiency. Based on the equipment cost provided by Metso, HGI's rough order of magnitude installed cost for SCR at YELP is between $11,000,000 and $14,000,000 per boiler. The installed cost at CELP is slightly less at $10,500,000 to $13,000,000. This cost range includes upgrading or replacing the existing ID fans and supporting equipment as it is mostly likely required to overcome the increased flue gas pressure drop through the SCR catalyst. The largest part of the operating cost for SCR is the catalyst replacement cost and because there is limited experience with these fuels and CFBs retrofitted with SCR these costs could be considerable more than indicated in the reports due to fouling and plugging of the catalyst.

Suite 1500
1999 Broadway
Denver, CO 80202-5731
Phone: (303) 291-0355
Fax: (303) 291-0136
www.harrisgroup.com

There is not an extensive list of circulating fluid bed boilers that have been retrofitted with SCR technology in North America. Because of this fact coupled with the unique fuel burned at each of the plants, installation of SCR is not recommended. If forced to install the technology, an extensive research effort is recommended including test burning the fuels with a test catalyst to help determine effectiveness, fouling and plugging potential, and catalyst life expectancy.

If you have any questions and need additional information please call me at 303 223-6726.

Sincerely,

HARRIS GROUP INC.

S. D. McCormick

Steven D. McCormick
Project Manager

SDM:smk

cc: R. D. Wankner
Project File

65353\docs\Siddoway-ROSI_022111.docx