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RECEIVED

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MT Dept. of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau

PHILLIPS 66

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e-RETURN RECEIPT REQUESTED

September 30, 2019

Craig Henrikson, P.E.
Air Quality Bureau
Montana Department of Environmental Quality
PO Box 200901
Helena, MT 59620-0901

Re: Regional Haze Four-Factor Analysis
Phillips 66 Billings Refinery

Dear Mr. Henrikson:

The attached report is in response to an email request from the Montana Department of Environmental Quality (MDEQ) to prepare a Regional Haze four-factor analysis for specific units located at the Phillips 66 Billings Refinery.

The analysis itself relates to the second planning period (Round 2) of development of a State Implementation Plan (SIP) to address Regional Haze in Montana Class I areas. 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 facilities in Montana that, if implemented, could be used to attain reasonable progress toward the visibility goals.

The four-factor analysis was conducted for oxides of nitrogen (NOx) on Boilers 1 and 2 as described by April 24 and May 3, 2019 emails from the MDEQ along with a more limited sulfur dioxide (SO2) discussion.

The results of the analysis have indicated that additional controls on Boilers 1 and 2 are not necessary to make reasonable progress due to costs and the lack of a measurable impact by Phillips 66 on any nearby Class I area.

Please feel free to contact me if you have any questions or if you need additional information.

Sincerely,

Steven R Torpey

Steven R. Torpey

Attachment

BISON
ENGINEERING, INC.

Regional Haze
Four-Factor Analysis

Phillips 66 Company

PHILLIPS
66

Billings Refinery
401 South 23rd Street
Billings, Montana

September 2019

Prepared by:
Bison Engineering, Inc.
1400 11th Avenue, Ste. 200
Helena, MT 59601

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by the Phillips 66 Company – Billings Refinery (Phillips 66) to prepare a four-factor analysis for specific units located at their petroleum refinery sited in Billings, MT. The four-factor analysis was requested by the Montana Department of Environmental Quality (MDEQ) in an email (and follow up discussions) between Steve Torpey (Phillips 66) and Craig Henrikson (MDEQ) 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 Phillips 66 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) on Boilers #1 and #2 (also referred to as emitting units #51 and #52 in the MDEQ annual emission inventory) at the Phillips 66 Billings Refinery as described by April 24 and May 3, 2019 emails from Craig Henrikson of MDEQ along with a more limited sulfur dioxide (SO_2) discussion. In addition, facility-wide emissions reduction efforts have also been described in this analysis. The results of the analysis have indicated that additional controls on Boilers #1 and #2 are not necessary to make reasonable progress due to costs and Phillips 66'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 ACRYNOMS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Bison	Bison Engineering, Inc
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FCCU	Fluidized Catalytic Cracking Unit
FGD	Flue gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
ID Fan	Induced Draught Fan
Jupiter Plant	Jupiter Sulphur LLC sulfur recovery operations
Lb/MMBtu	Pounds per Million British Thermal Units
MDEQ	Montana Department of Environmental Quality
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
NO_x	Oxides of Nitrogen
O_2	Oxygen
O&M	Operations and Maintenance
Phillips 66	Phillips 66 Company – Billings Refinery
ppm_v	parts per million by volume
r	Pearson Correlation Coefficient
r^2	the square of the correlation coefficient r
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
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
ULNB	Ultra-Low NO_x Burners

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. (The entire visibility program is found in 40 CFR 51.300 to 309). These requirements state individual states are required to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 (40 CFR 51.308(d)(1)).

The Environmental Protection Agency (EPA), via a Federal Implementation Plan (FIP) promulgated the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) and a four-factor analysis for various sources in Montana.[1] Phillips 66 and the other Montana refineries were not considered for analysis at the time presumably due to their recent investment in and installation of pollution control technologies as a result of the EPA Refinery Consent Decree process. 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 Phillips 66 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. Additional discussions with MDEQ (as described by April 24 and May 3, 2019 emails from Craig Henrikson of MDEQ) narrowed the four-factor analysis to NO_x on Boilers #1 and #2 at Phillips 66 with broader SO_2 and NO_x discussions across the refinery units. 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. Phillips 66 chose the

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

2017-2018 annual emission years as that representative baseline. Those 2017-2018 annual emissions years are also used as a basis for this four-factor analysis.

2.1 Facility Information

Phillips 66 is an integrated petroleum refinery that includes crude oil distillation, delayed coking, fluid catalytic cracking, hydrotreating, alkylation, and other associated petroleum refining processing units and auxiliary operations. Associated with Phillips 66 are the adjacent Jupiter Sulphur LLC sulfur recovery operations (Jupiter Plant), which recover sulfur from the sour-acid gas streams generated at Phillips 66. For air permitting purposes, the Phillips 66 and Jupiter Plant are treated as a single stationary source.

Phillips 66 encompasses approximately 200 acres and the location of the main refinery gate is 401 South 23rd Street, Billings, Montana. The legal description of the site location is NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County, Montana. The site elevation is 3,125 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 Phillips 66. *Figure 2* is a printout of a Google Earth satellite photo of the area surrounding the facility, with the site location indicated.

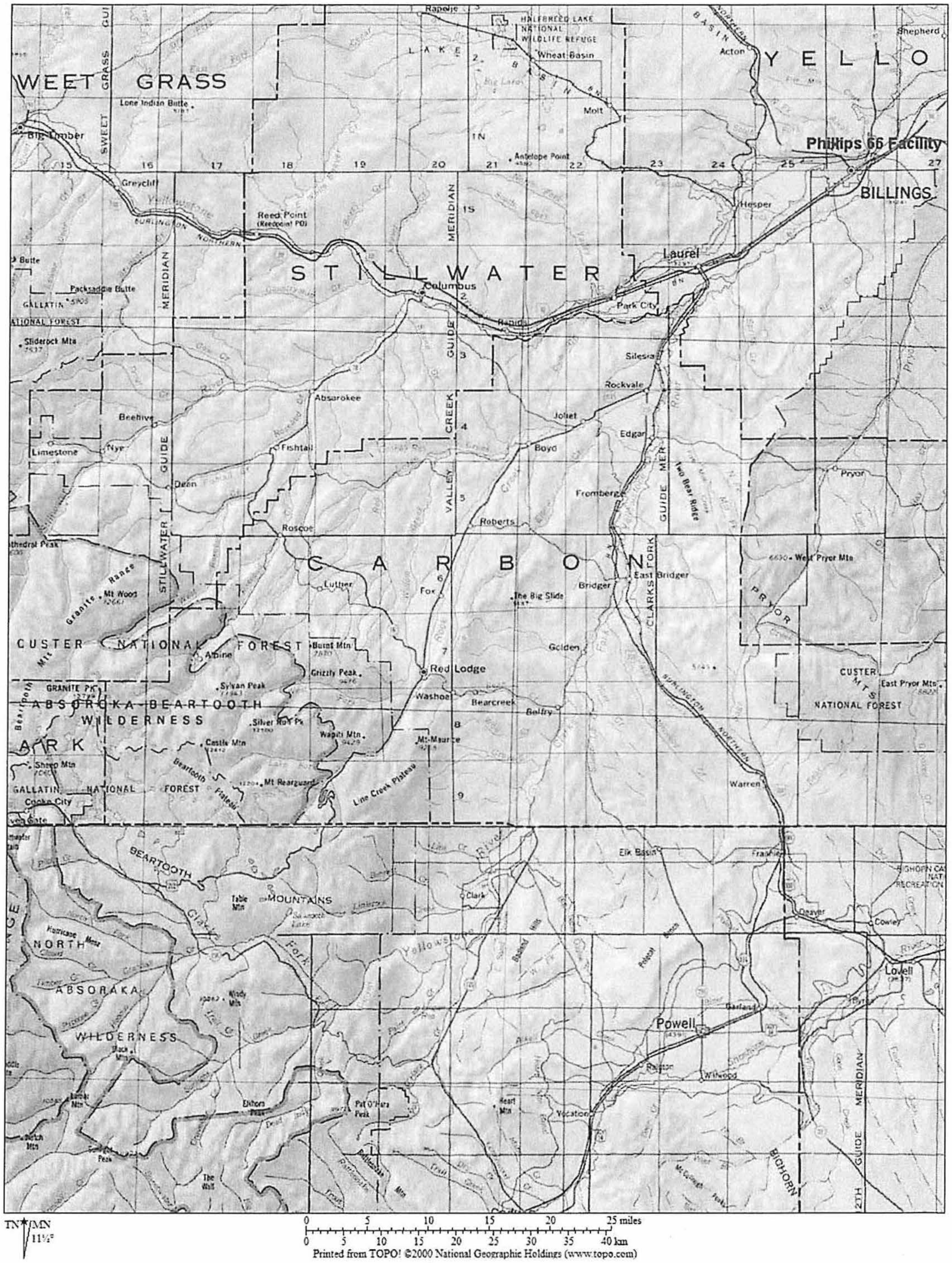

Figure 1: Topographic Map of Phillips 66 in relation to nearest Class I area

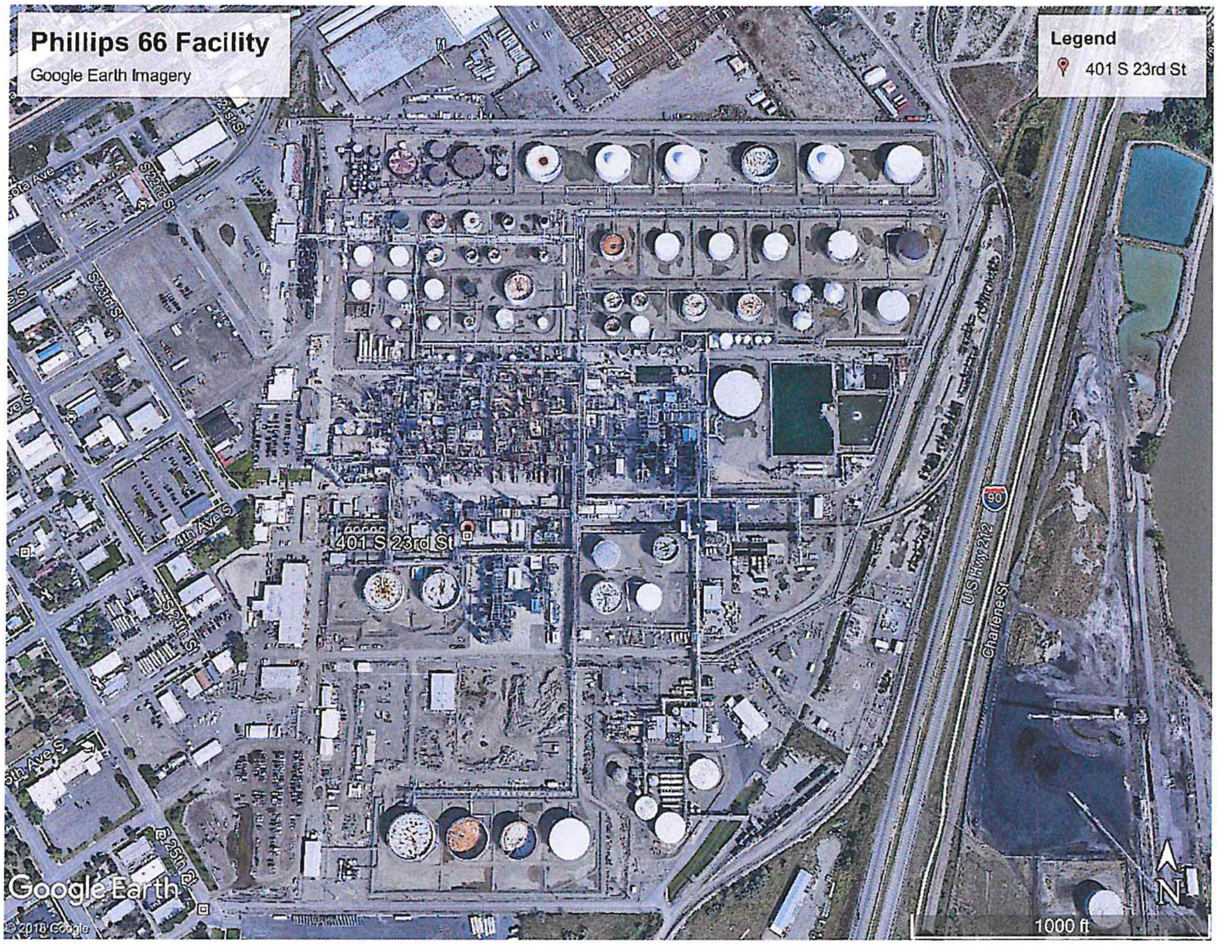

Figure 2: Google Earth representation of Phillips 66 facility

3.0 PROGRAM SUMMARY and STATUS

As previously stated, the Regional Haze program is an attempt to attain 'natural' (nonanthropogenic) visibility conditions in all mandatory Class I areas[2] by 2064. The RHR itself was promulgated in substantially its current form in 1999 with adjustments made in 2017.[3] 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[4] the four-factor program, applied to 'larger' facilities who had a potential of impacting (visibility) in a mandatory Class I area. Phillips 66 was excluded from both analyses under Round 1.

3.1 Montana Initiatives

For Montana, the 1st planning period (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.[5] Following much discussion and analyses, EPA six years later promulgated a FIP as it applied to sources in Montana.[6] As previously discussed, Phillips 66 was not included in the FIP, therefore, no additional or new controls were required for Phillips 66 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

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[2] 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.

[3] 64 FR 35765; July 1, 1999; and 82 FR 3124; Jan. 10, 2017.

[4] The BART program is more fully explained in 40 CFR 51.308(e).

[5] Letter from DEQ to EPA dated July 19, 2006.

[6] The proposed FIP was published April 20, 2012 at 77 FR 23988 and became final on Sept. 18, 2012 at 77 FR 57864.

land managers (primarily the National Park Service and the US Forest Service). The 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 Phillips 66 for the given time period (4.51 specifically, based on the 2014-2017 annual emission inventory period) and thus was chosen by MDEQ for a four-factor analysis for Round 2.

The Western Regional Air Partnership (WRAP), which Montana is a member, proposed Q/d > 10 as the analysis threshold, which would not have included Phillips 66. Montana decided to use 4 as the screening level; therefore Phillips 66 was not screened out of this analysis. See Table 1 for the relationship of Phillips 66 to other facilities included in the Round 2.

Table 1: Montana Permitted Stationary Sources With Q/d >4 (Q- Avg NO_x +Avg SO_2)

COMPANY	FACILITY NAME	"Q" NOx+SO2	Nearest CIA	"d" Distance to CIA (km)	Q/d
TALEN MONTANA LLC	COLSTRIP STEAM ELECTRIC STATION #1-4	22,865	U.L. Bend	198.9	114.96
WEYERHAEUSER NR - COLUMBIA FALLS	WEYERHAEUSER-CFALLS	984	Glacier	13.3	74.01
ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT	1,235	Gates of the Mts	30.6	40.36
MONTANA DAKOTA UTILITIES CO	MDU - LEWIS & CLARK STATION	1,052	Teddy Roosevelt	51.8	20.31
OLDCASTLE MATERIAL CEMENT HOLDINGS, INC.	TRIDENT	1,488	Yellowstone	97.4	15.28
YELLOWSTONE ENERGY LIMITED PARTNERSHIP	YELLOWSTONE POWER PLANT	2,136	N Absaroka	143.8	14.86
ROSEBURG FOREST PRODUCTS CO	ROSEBURG FOREST PRODUCTS	303	Selway Bitterroot	26.6	11.38
COLSTRIP ENERGY LTD PARTNERSHIP	COLSTRIP ENERGY LTD PARTNERSHIP	1,936	U.L. Bend	188.7	10.26
MONTANA SULPHUR & CHEMICAL CO	MONTANA SULPHUR & CHEMICAL	1,310	N Absaroka	137.5	9.53
GRAYMONT WESTERN US INC	GRAYMONT WESTERN US INC	524	Gates of the Mts	57.1	9.18
EXXONMOBIL FUELS & LUBRICANTS COMPANY	EXXONMOBIL BILLINGS REFINERY	1,034	N Absaroka	143.7	7.20
CENEX HARVEST STATES COOPERATIVE INC	CHS INC REFINERY LAUREL	629	N Absaroka	113.5	5.54
F H STOLTZE LAND & LUMBER CO	F.H. STOLTZE LAND AND LUMBER CO	75	Glacier	14	5.37
SIDNEY SUGARS INC	SIDNEY SUGAR FACILITY	269	Teddy Roosevelt	51.9	5.18
PHILLIPS 66 CO	**BILLINGS REFINERY**	645	N Absaroka	143	**4.51**
WEYERHAEUSER NR - KALISPELL	WEYERHAEUSER-EVERGREEN	134	Glacier	30.5	4.40
NORTHERN BORDER PIPELINE CO	N. BORDER PIPELINE CO STA. 3	96	Medicine Lake	22.8	4.20

3.2 Federal Initiatives

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

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

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

The visibility program may be thought of as the implementation of two sub-programs. One regards new source review (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 Phillips 66 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 as a direct result of the application of the control (i.e., a discernible improvement in deciviews[7]) in a Class I area.

To that end, Phillips 66 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.[8] 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].

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[7] The definition of a deciview is as follows: Deciview haze index=10 $\ln_e(b_{ext}/10\ \mathrm{Mm}^{-1})$. 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.

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

As will be presented in following sections of this document, no measured evidence of any impact by Phillips 66's operations on the visibility in any mandatory Class I airshed was established.

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.

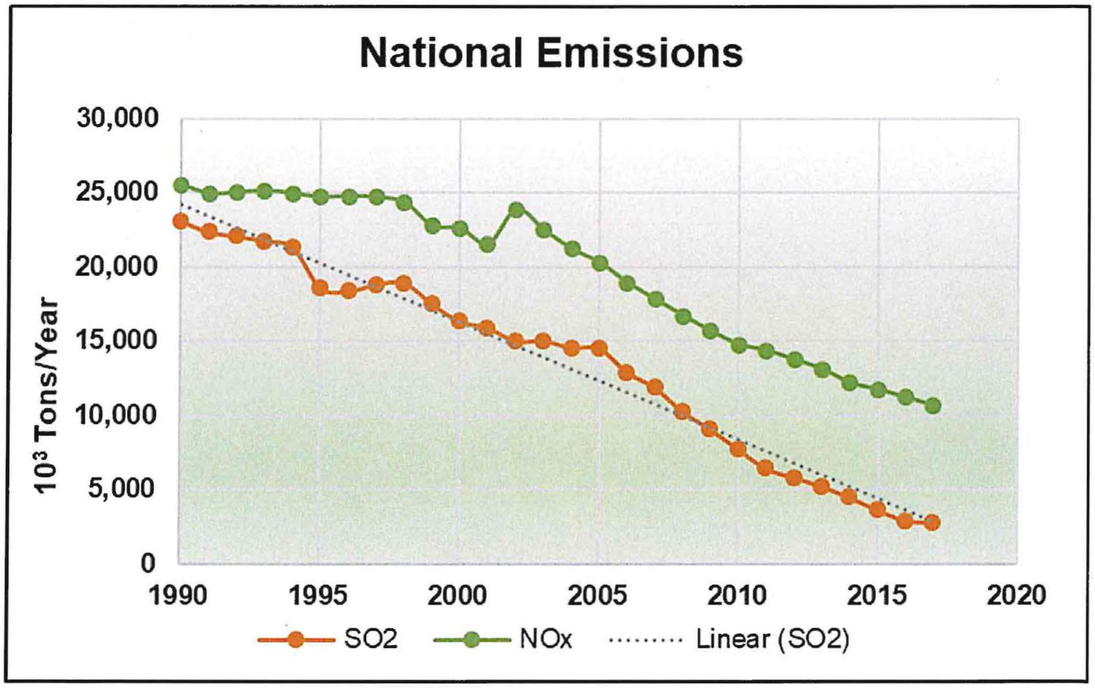

Figure 3: National Emission trends of SO_2 and NO_x

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 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.

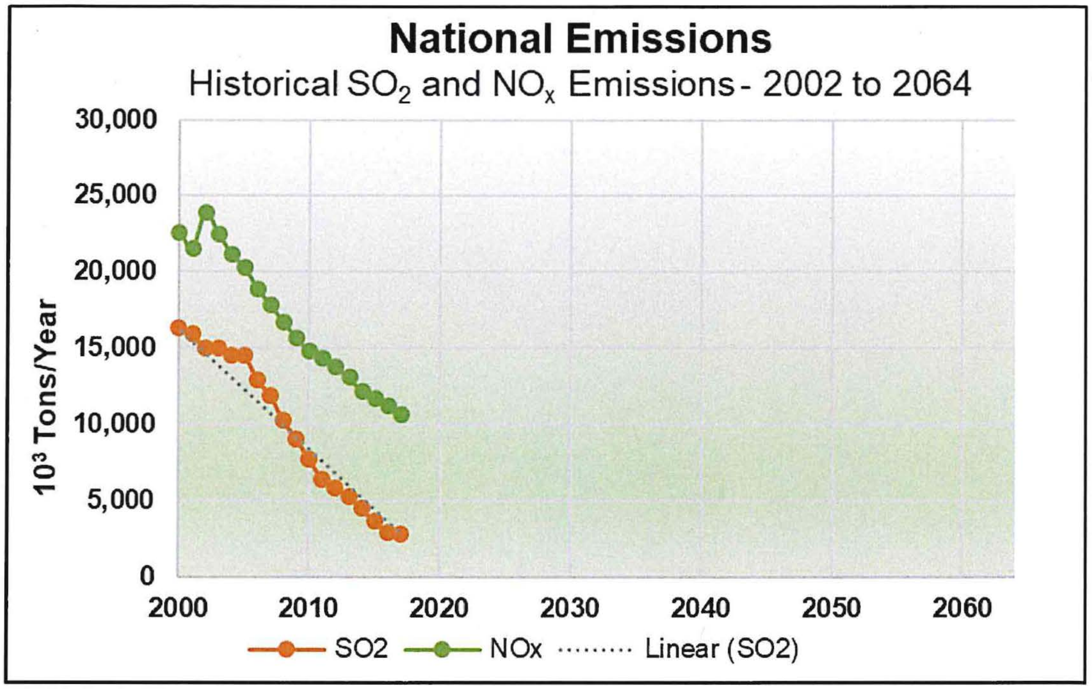

Figure 4: Historical SO_2 and NO_x Emissions

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; Montana has been doing its part to reach the national goal.[9]

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[9] 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 Phillips 66 NOx and SO_2 emissions in particular and a measurable impact on visibility (expressed in deciviews).

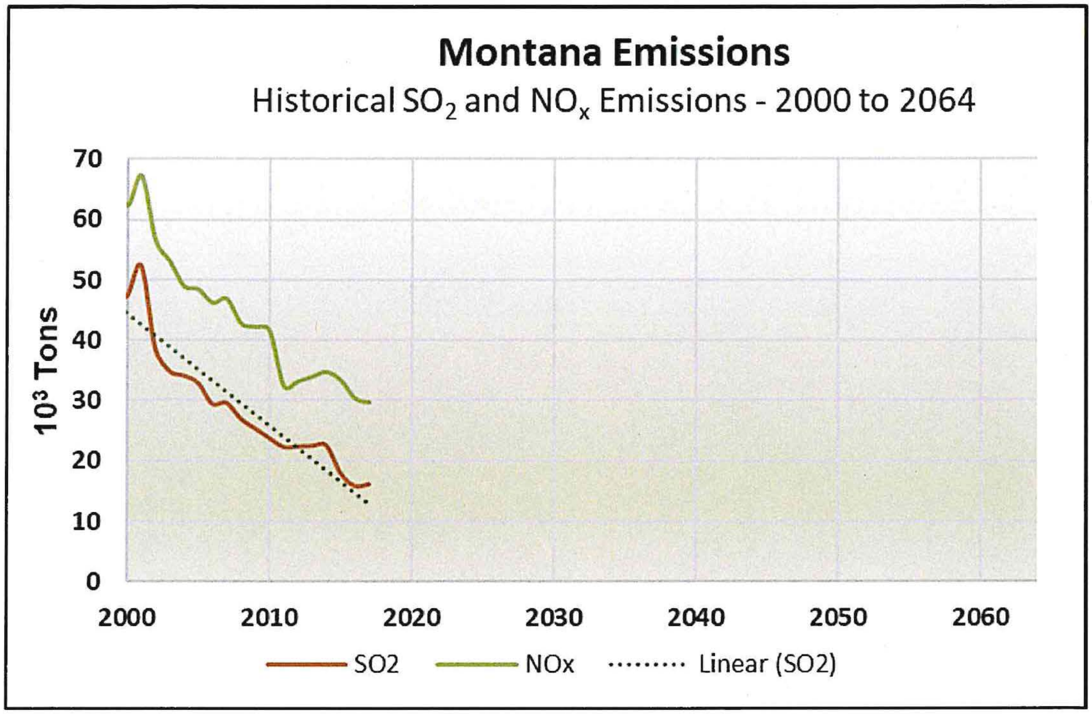

Figure 5: Montana Industrial SO_2 and NO_x emissions

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.[10]

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 Phillips 66, the CHS Laurel Refinery, the ExxonMobil Billings Refinery, Montana Sulphur and Chemical Company, Western Sugar, and Yellowstone Energy Limited Partnership. 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 as dramatically.

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[10] 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, Phillips 66 included, does not translate to an improvement in Class I visibility; linear or otherwise.

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.

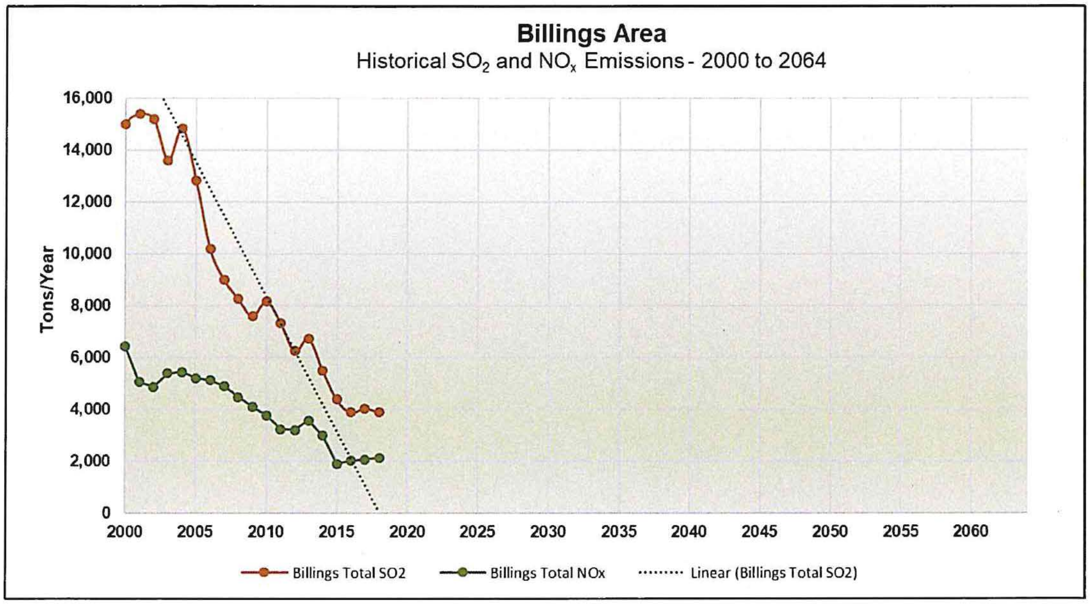

Figure 6: Billings Area SO_2 and NO_x Emissions from 2000 to 2064

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 done more than its fair share for the RHR program and no further action is recommended for Round 2.

4.4 Phillips 66 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 ascertain important criteria that will lead to the selection of specific reasonable progress requirements.

The RHR program (under MDEQ or EPA) has not previously considered Phillips 66's emissions as appropriate candidates for additional control under the reasonable progress (or any other) criteria. First, Phillips 66's emissions (historical and current actuals) have been addressed and controlled by separate implementation plans, voluntary emission limitations, the federal refinery consent decree, and by subsequent federal implementation plan actions between 1998 and 2008.

Second, Montana and more particularly Billings-area emission inventory data (shown above) clearly shows substantial and adequate 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 roughly 85% 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].[11] 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.

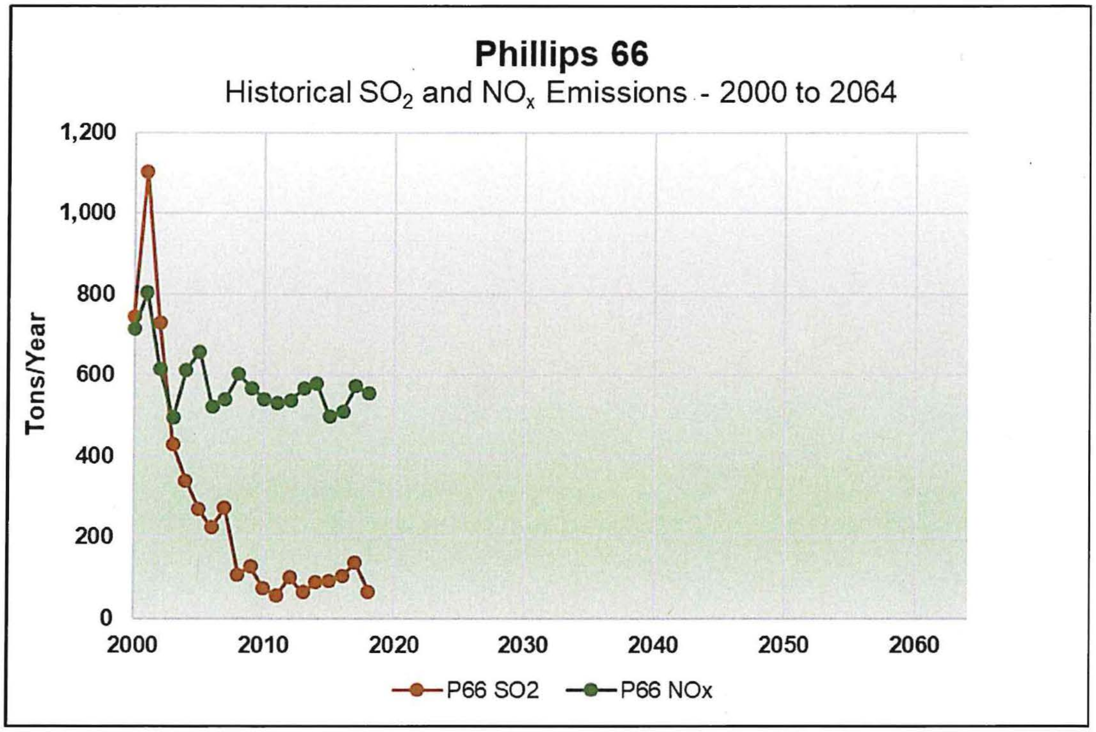

Figure 7: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2064

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[11] 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.

Consistent with previously shown data, the rate of reduction of emissions represents a rate that is beyond "reasonable progress" in attaining the national goal, particularly with respect to SO_2.

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 emissions. A review of anthropogenic sources, and to what extent, these sources actually impact the Class I area of interest was completed to determine the anthropogenic impact on visibility. There are several methods one may employ to determine if any emission reduction would lead to an improvement in visibility at a 'nearby' Class I areas. This analysis reviews the information in retrospect, and also discusses how that data informs predictions of future visibility impacts.

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from Phillips 66 itself or combined with other nearby sources.

In addition to emissions data, there is concurrent visibility data at all the 'nearby' Class I areas, see Table 2. Visibility data from these areas was taken from WRAP[8] and generated from the Interagency Monitoring for Protected Visual Environments (IMPROVE)[1,2,9]. These areas and their closest proximity to Phillips 66 are shown below.

Table 2: Nearby Class I Areas and Proximity

Nearby Class I Area	**Approximate Distance from Phillips 66 (*kilometers*)**
North Absaroka Wilderness Area	143
Yellowstone National Park	145
UL Bend Wilderness Area	190
Gates of the Mountains Wilderness Area	270
Theodore Roosevelt National Park	405

Emissions data from Phillips 66 spans both the baseline period for the visibility program (2000 to 2004) as well as Round 1 (2005 to 2018). 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 Phillips 66 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

Phillips 66 has a significant increase or decrease in emissions during the monitoring period (2000 to present), it is logical to assume that the deciview parameter followed 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 Phillips 66. It is roughly 143 kilometers SW of 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].

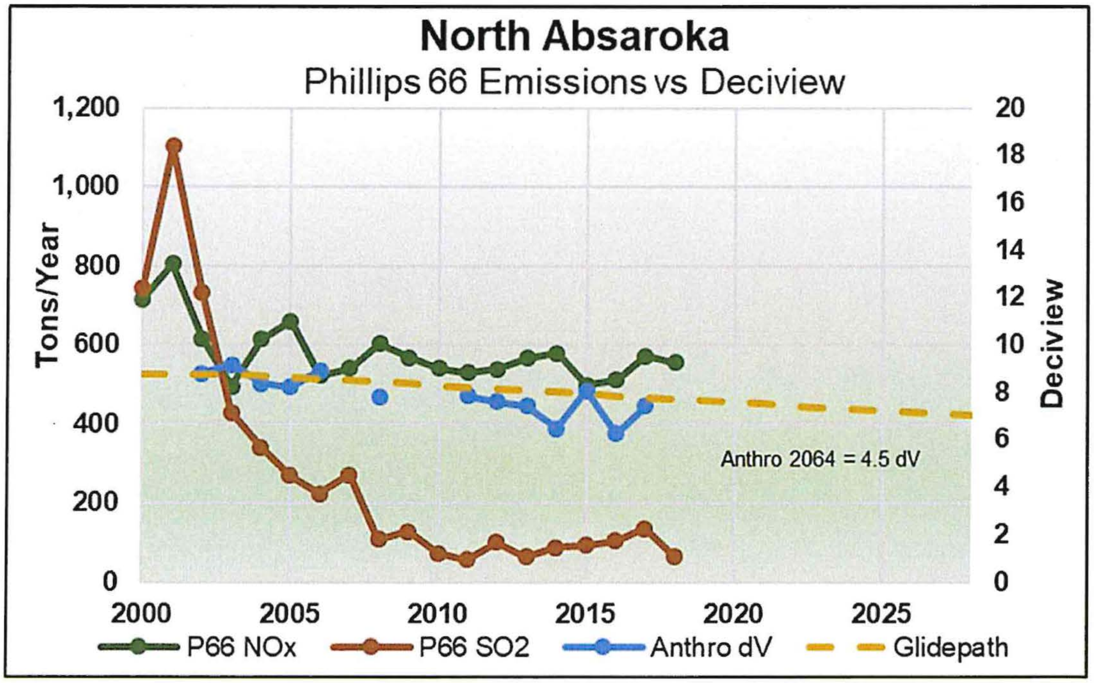

Figure 8: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2018 compared with the North Absaroka Wilderness Area visibility glidepath through 2028

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[12] at North Absaroka Wilderness Area with Phillips 66 SO_2 and NO_x

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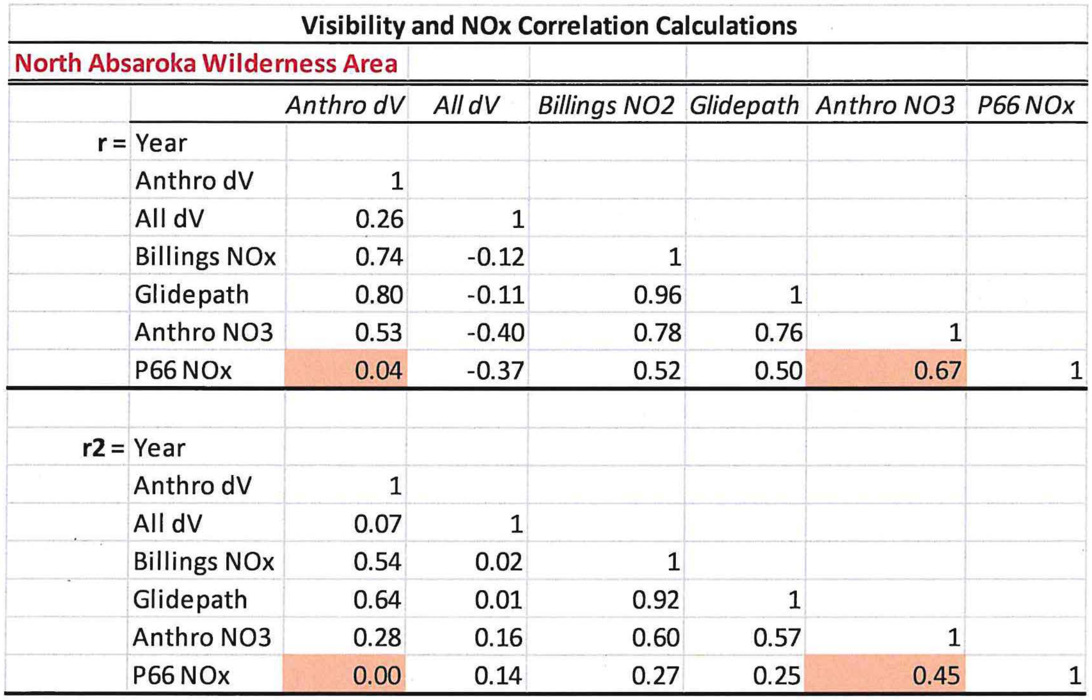
[12] The "glidepath" is a straight line of deciviews starting at the baseline (≈ 2000-2004) through the 2064 endpoint of the RHR program. The "endpoint" is the final desired deciviews which represents "remedying of … existing impairment of visibility … which … results from manmade pollution." (Clean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

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.

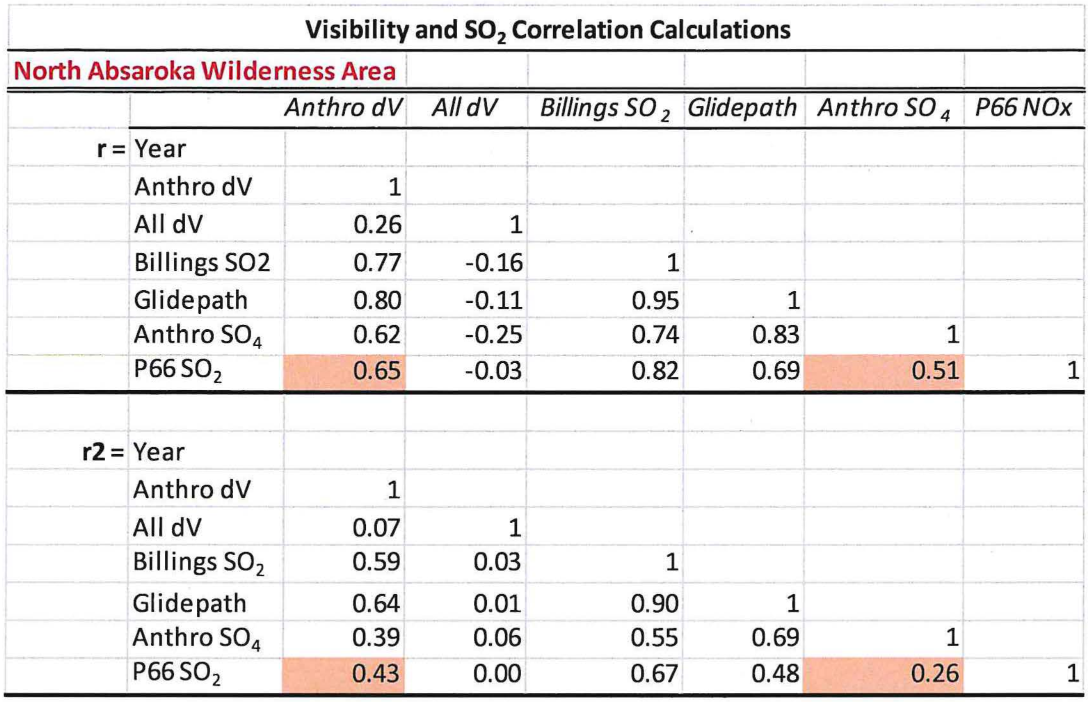


Visibility and NOx Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.53	-0.40	0.78	0.76	1	
	P66 NOx	0.04	-0.37	0.52	0.50	0.67	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 NO3	0.28	0.16	0.60	0.57	1	
	P66 NOx	0.00	0.14	0.27	0.25	0.45	1

Figure 9: Correlation Analysis for Phillips 66 NO_x and Visibility Indicators at North Absaroka Wilderness Area



Visibility and SO_2 Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	All dV	Billings SO_2	Glidepath	Anthro SO_4	P66 NOx
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Billings SO2	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	
	P66 SO_2	0.65	-0.03	0.82	0.69	0.51	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	
	P66 SO_2	0.43	0.00	0.67	0.48	0.26	1

Figure 10: Correlation Analysis for Phillips 66 SO_2 and Visibility Indicators at North Absaroka Wilderness Area

To complete the evaluation a correlation analysis is also presented in *Figures 9 and 10*. 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 Phillips 66 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, Phillips 66 NO_x emissions were not at all related to Anthro dV (overall human caused visibility impairment)[13] at an r value of 0.04 but was somewhat related to the Anthro NO_3 value (the portion of anthropogenic visibility impairment tied to NO_3 compounds) at 0.67. With respect to SO_2, a slight trending relationship was seen

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

between Anthro dV, Anthro SO_4 (the portion of anthropogenic visibility impairment tied to SO_4 compounds) and Phillips 66 SO_2 emissions (at r values of 0.65 and 0.51, respectively), likely because all three were trending down. Correlation does not imply causation, as is suggested here. However, no clear correlations/relationships in data were observed.

4.5.2 Yellowstone National Park Visibility vs Emissions

Yellowstone National Park is the next Class I area for consideration. It is roughly 145 kilometers WSW of the facility to the border of the national park. The figure compares visibility (Anthro dV) and the RHR glidepath at Yellowstone National Park with Phillips 66 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. In addition, the rate of SO_2 emission reduction from Phillips 66 vastly outpaces the modest rate of visibility improvement.

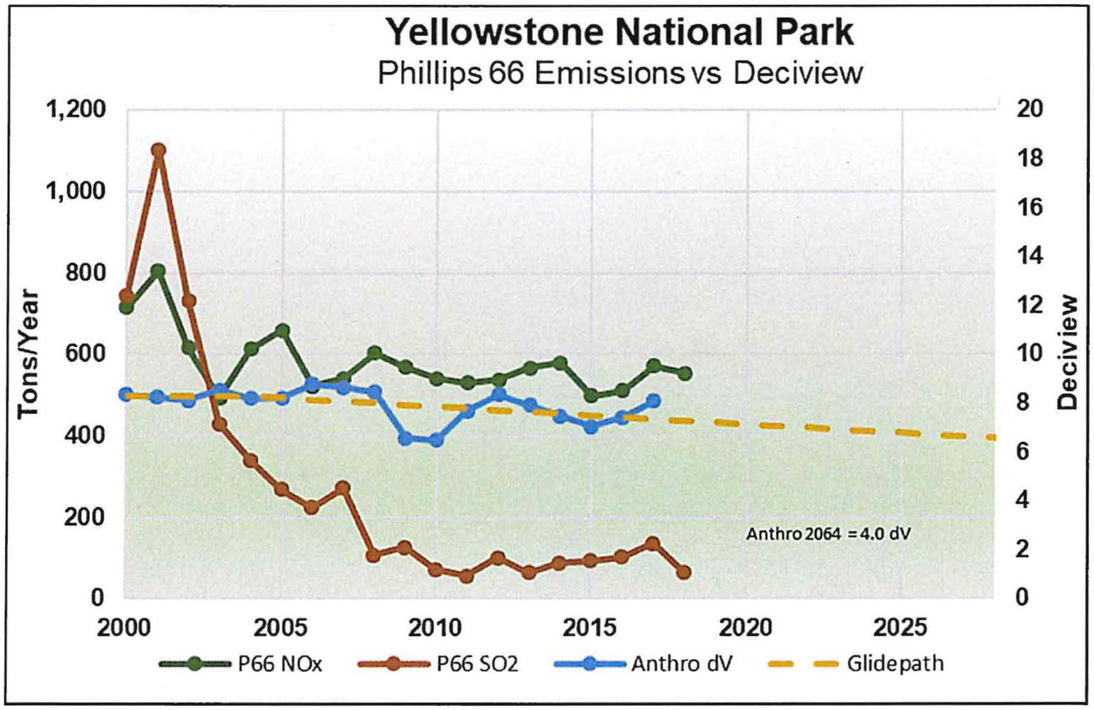

Figure 11: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2018 compared with the Yellowstone National Park visibility glidepath through 2028

The full correlation analysis results are available in *Appendix A*, but no evident correlations are seen between the visibility data and Phillips 66 emissions with the exception of sharing a general downward trend.

4.5.3 UL Bend National Wildlife Refuge Visibility vs Emissions

Another Class I area to consider is the UL Bend National Wildlife Refuge. This area is located about 190 kilometers NNE of the Phillips 66 refinery. A graphical review of the emissions and visibility data over time is provided below.

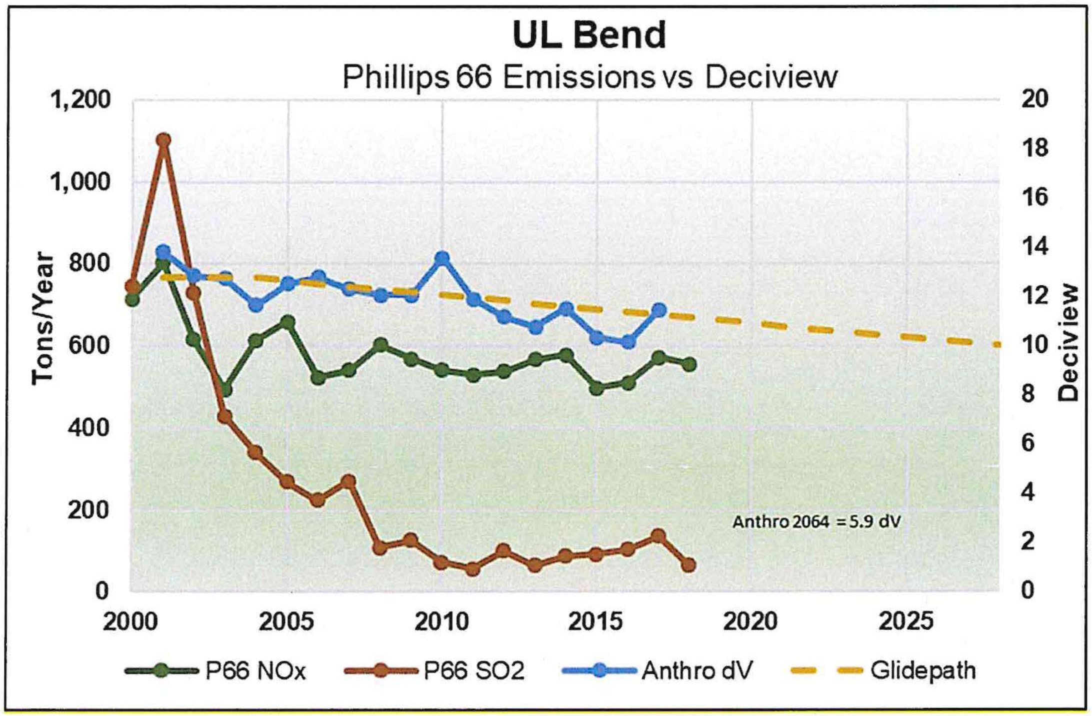

Figure 12: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2018 compared with the UL Bend National Wildlife Refuge visibility glidepath through 2028

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

In addition to the graphic, the correlation data in *Appendix A* shows a possible trending relationship between Anthro dV, Anthro NO_3 (the portion of anthropogenic visibility impairment tied to NO_3 compounds) and Phillips 66 NO_x emissions (at r values of 0.49 and 0.46, respectively), likely because all three were trending down. However, the r^2 data shows that less than 24% and 21% of the data indicate linear correlation. Again, no clear correlations/relationships in data were observed.

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 WNW of the Phillips 66 refinery making it an area very unlikely to be impacted by Phillips 66. Nonetheless a review of that data was undertaken. A graphical review of the emissions and visibility data over time is provided below.

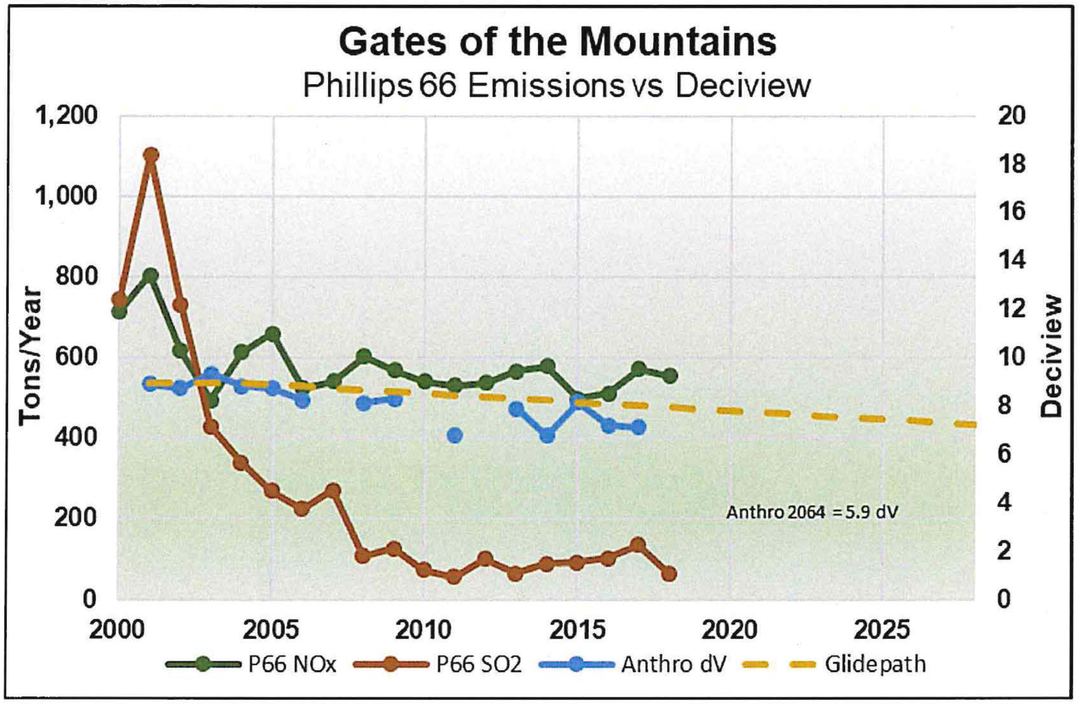

Figure 13: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2018 compared with Gates of the Mountains Wilderness Area visibility glidepath through 2028

The graphic reveals a few interesting features. First, the rate of emission improvement for Phillips 66 emissions reductions is faster than any rate of change for deciviews. Second the visibility improvement is ahead of the desired uniform rate of progress wanted for the program. Finally, the current visibility (mean for past 5 years) is at or near the desired level for this 2nd planning period.

No correlations greater than 0.50 are seen in the correlation analysis in *Appendix A*, which is to be expected given the distance and the prevailing winds. Any small correlation would be assumed to be related to the overall downward trending.

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 NW of Phillips 66 and is therefore highly unlikely to be impacted by Phillips 66 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.

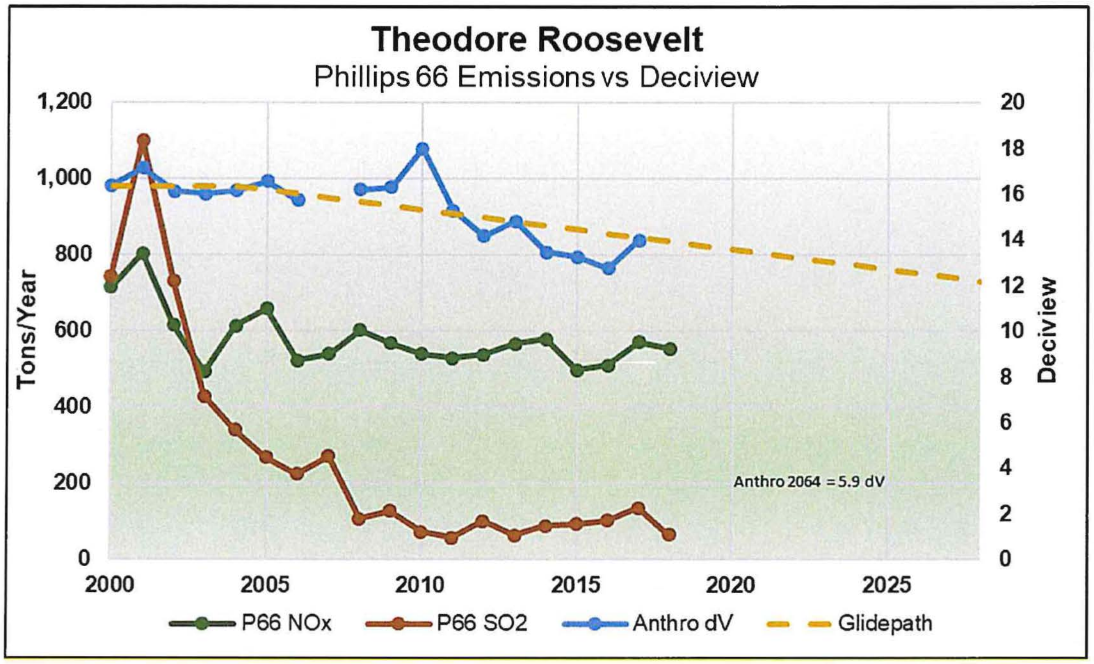

Figure 14: Phillips 66 SO_2 and NO_x Emissions from 2000 to 2018 compared with Theodore Roosevelt National Park visibility glidepath through 2028

The graphic reveals a faster rate of change (improvement) in Phillips 66 emissions (particularly SO_2) than a concurrent improvement in visibility. Thus, it would not be logical to equate a change in Phillips 66 emissions with a measurable improvement in visibility.

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 Phillips 66, however, do not share this same trend. Again, a reduction in emissions does not seem to suggest an improvement in visibility impairment data.

Given the great distances involved and the fact that there is minimal correlation between visibility data and Phillips 66 emissions (the only r value above 0.50 is the Anthro NO3 and Phillips 66 NO_x emissions, both trending downward overall), it is reasonable to conclude that Phillips 66 is not a candidate for emissions reductions to improve visibility at this National Park.

5.0 FOUR-FACTOR ANALYSIS

Per the email from MDEQ dated March 13, 2019, a four-factor analysis was completed for Phillips 66. This facility was selected by the MDEQ because of a "Q/d" analysis, used by MDEQ to screen facilities for Round 2.[14] MDEQ's Q/d analysis used 4.0 as their action threshold for analysis. The Phillips 66 Billings Refinery had a Q/d of 4.51, just over the action threshold for 2014-2017 average emissions. Refineries, such as Phillips 66, are non-typical emissions sources with respect to previous RHR rule analyses because they are made up of many smaller emissions units, as opposed to one or two large emissions sources from other MDEQ identified facilities with Q/d ratios over 4. As indicated in *Table 1*, Phillips 66 is ranked 15 out of 17 facilities subject to analysis in Round 2.

This analysis focuses on emissions originating from the #1 and #2 Boilers at the facility because these two units are responsible for approximately 22% of the NO_x emissions from the plant (based on 2018 emissions). In an email dated, April 24, 2019, MDEQ stated "*Montana DEQ believes characterizing current controls and possible additional controls for Boiler #1 and Boiler #2 would satisfy the four-factor analysis. For 2018, these two boilers combined had NO_2 emissions totaling over 120 tpy.*" SO_2 emissions will also be addressed generally and refinery-wide below.

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 is 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

The most common SO_2 control practice that may be applied to typical refinery boilers and other combustion devices (heaters, flares, etc.), specifically those fired with refinery fuel gas, is compliance with the Standards of Performance for Petroleum Refineries (NSPS, 40 CFR 60, Subpart J and Ja). That standard includes a hydrogen sulfide content limit of 162 parts per million by volume (ppm_v) or less in refinery fuel gas on a 3-hour rolling average basis. All combustion devices fired with refinery fuel gas at the Phillips 66 Billings Refinery are subject to and comply with this standard. In addition, other standards apply from terminated EPA Consent Decree requirements (that have largely been memorialized in permit conditions), state SIP requirements, and other NSPS limits to further control SO_2 emissions from the fluidized catalytic cracking unit (FCCU), among other units.

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

5.1.1 SO_2 Four-Factor Analysis and Summary

For the 2017-2018 baseline summary, Phillips 66 averaged 100.67 tons per year of SO_2 emissions over 38 emissions sources/points that have the potential to emit SO_2. While those emissions are not evenly distributed over those sources, many of the SO_2 sources are small boilers or heaters subject to NSPS Subpart J/Ja or other requirements or are larger well-controlled SO_2 sources (the FCCU or sulfur recovery units, for example).

5.2 NO_x Control Measures

As previously discussed with respect to SO_2, the terminated EPA Consent Decree included significant emissions reductions for units across the refinery. These reductions included a NO_x Control Plan for heaters and boilers (implementing NO_x controls on at least 30% of the heater and boiler capacity greater than 40 million British Thermal Units per hour, MMBtu/hr) as well as catalyst additive demonstrations at the FCCU (with an associated NO_x emission limit). NO_x reductions were evaluated and implemented on units where the investment would provide the most efficient emission reduction value. Phillips 66 has made great efforts through the terminated Consent Decree and beyond, to reduce NO_x emissions in the recent past.

The NO_x analysis also focuses on Boilers #1 and #2 as these two units are responsible for approximately 23% of the NOx emissions from the plant (based on the 2017-2018 baseline emissions). Twenty-one other NO_x sources (with greater than five tpy emissions) split the other 77% of the NO_x emissions, with three of those sources being grouped sources (gasoline engines, for example, or units with multiple fuel types in the inventory). Many of those twenty-one sources already have seen recent emissions control upgrades under the terminated Consent Decree.

There are several ways to control NO_x emissions from a boiler. Some methods utilize combustion modifications that reduce NO_x formation in the boiler itself, while others utilize add-on control devices at various points in the exhaust path to remove NO_x after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NO_x. The identified applicable NO_x control technologies are described below and include: Ultra Low NO_x Burners with Flue Gas Recirculation, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction. The NO_x basis ("uncontrolled emissions") for Boilers #1 and #2 is the current MDEQ annual emission inventory factor of 0.27451 lb/MMBtu.

5.2.1 Combustion Controls – Ultra Low NO_x Burners with Flue Gas Recirculation

Combustion controls are features of the boiler that reduce the formation of NO_x at the source. Ultra Low NO_x Burners (ULNB) are a common combustion control, particularly for new boilers, which typically include Flue Gas Recirculation (FGR), and are intrinsic to boiler operation when installed. Each is addressed separately below.

5.2.1.1 ULNB

ULNB 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. ULNB may result in increased carbon monoxide (CO) and hydrocarbon emissions, decreased boiler efficiency and increased fuel costs.

5.2.1.2 FGR

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 oxygen (O_2) concentration in the combustion zone.

Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NO_x reductions), they generally occurred on smaller, newer, low burner count units. While EPA has noted efforts to provide cost control information for low NO_x and ultra-low NO_x burners, none has been completed [12]. Based on corporate information, practices and similar unit Consent Decree-required retrofits, Phillips 66 believes this type of a retrofit for Boilers #1 and #2 would be a difficult and expensive effort that would likely result in complete demolition and replacement of both boilers, at an estimated cost of $40 million for both ($20 million per boiler).

To annualize that cost and provide a cost per ton value for new RFG-(Refinery Fuel Gas) fired boilers equipped with ULNB and FGR, a NO_x limit of 0.03 lb/MMBtu was used. This assumes the new boilers are of the same general size/capacity as Boilers #1 and #2 and general utilization. The 0.03 lb/MMBtu NO_x limit comes from the recent retrofit of Boiler-5 and Boiler-6 at the Phillip 66 Billings Refinery. The $40 million total cost includes capital expenditures and demolition for both boilers but does not include annual maintenance costs associated with UNLB/FGR.

5.2.2 Selective Non-Catalytic Reduction (SNCR)

Per the April 2019 update of the EPA Cost Control Manual [13], 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 NOx 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 NOx 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 NOx vary considerably for this technology, depending on inlet NOx 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. None of the *refinery* process units or industrial boilers listed in EPA's applicable information collection request [13,14] used ammonia; all used urea based on the unique operational considerations. Therefore, urea was employed as the reagent in the Phillips 66 SNCR cost analysis.

The median reductions for urea based SNCR systems in various industry source categories range from 25 to 60 percent [13]. Additional industry-specific unit information included in the SNCR White Paper [15], provided boiler size and associated NO_x reductions. In the "Refinery Process Units and Industrial Boiler" section, for units less than 200 MMBtu/hr (the Phillips 66 Boilers #1 and #2 are both rated 120 MMBtu/hr). The 200 MMBtu/hr was used as a logical cut-off for smaller industrial boilers and the range estimated a 40 to 62.5% NO_x reduction. An average reduction of 58.5% was used in the cost efficiency calculations.

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 (<50 MW) due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers[13]. The costs provided for SNCR in the Four-Factor Analysis were calculated using EPA's SNCR Cost Calculation Spreadsheet and use the "retrofit factor" of 1 – average retrofit. The Spreadsheet states that its use is particularly for boilers (coal-, oil-, and natural gas-fired) with maximum heat capacities greater than or equal to 250 MMBtu/hr. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, Phillips 66 believes that the costs calculated are highly conservative.

5.2.3 Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH_3) or urea is used as the reducing agent.

SCR is typically implemented on stationary source combustion units requiring a higher level of NO_x reduction than may be achievable by SNCR or combustion controls. Theoretically, SCR systems can be designed for NO_x removal efficiencies up close to 100 percent. In practice, 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. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu) [15,16][15]. Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for Boilers #1 and #2 is 85.4%. This is based on current engineering mass balance/emissions factor of 0.2745 lb/MMBtu in the annual emissions reporting to 0.04 lb/MMBtu.

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 [17]. 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 [17]. 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 (and is the default for the EPA's SCR Cost Calculation Spreadsheet), it was used in the reagent calculations for Boilers #1 and #2 [18].

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

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

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.

Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). 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. For this application, both boilers combust clean fuels (refinery fuel gas), and particulate loading is not anticipated to be a problem, therefore a low dust SCR would be appropriate

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 (not applicable for this purpose) 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 [19]. Specific factors that impact the retrofit costs include the following [17]:

- Amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing electrostatic precipitators (ESPs) or particulate control devices, 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 devices; and
- Number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

As previously discussed for SNCR, there is an efficiency of scale associated with pollution control equipment installation. Because the cost calculator is based on units with a heat capacity greater than 250 MMBtu/hr, those efficiencies are included in the EPA spreadsheet estimates. The costs provided for SCR in the four-factor analysis that follows are calculated using EPA's SCR Cost Calculation Spreadsheet also use the "retrofit factor" of 1 – average retrofit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, Phillips 66 believes that the costs calculated for SCR are also highly conservative.

5.3 Four-Factor Analysis and Summary - NO_x

5.3.1 Factor 1 – Cost of Compliance

For replacement of Boilers #1 and #2, the $40 million total estimate ($20 million each) was based on demolition of the existing boilers and replacement with new RFG-fired boilers of the same general capacity and utilization equipped with ULNB and FGR. The cost estimated was established from corporate experience/vendor estimates with that type of refinery boiler work. The annualized cost was determined using the following equation, using a present value of $20 million for each replacement boiler, an interest rate of 5.5%, and capital recovery period of 20 years:

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

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 [20].

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 Boilers #1 and #2 were taken from the baseline emission rate agreed to by MDEQ of 2017 and 2018 annual emission inventory years it relates to Round 2.

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 Table 3. Details of the calculations may be found in *Appendix B.*

Table 3: Estimated Costs of NOx Control Options for Phillips 66, ranked by Control Efficiency

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	Total Annual Cost (in 2018 dollars)	Cost Effectiveness ($/ton)
Boiler #1 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5	36	$233,041	$6,427
	SCR	85.4	56	$378,163	$6,791
	Replacement with new boiler equipped with ULNB and FGR	89.0	58	$1,673,587	$28,855
Boiler #2 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5	36	$232,805	$6,445
	SCR	85.4	55	$378,069	$6,816
	Replacement with new boiler equipped with ULNB and FGR	89.0	58	$1,673,587	$28,855

The costs for additional control at Boilers #1 and #2 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 economies of scale associated with much larger (minimum twice as large) as Boilers #1 and #2 and use an "average" retrofit factor. EPA anticipates such retrofits are to be much more costly/more complex on smaller boilers. In addition, due to the lack of available space (footprint), the cost of SCR or SNCR would be higher than this calculation. However, even at this conservative level, these costs exceed BACT level cost per ton values at recently permitted units, even under major source permitting efforts.

5.3.2 Factor 2 – Time Necessary for Compliance

The Phillips 66 Billings Refinery relies on the consistent operation Boilers #1 and #2 for steam, which is intrinsic to refinery operation. Therefore, any major retrofits or maintenance on major refinery units is scheduled during every-five-year maintenance turnarounds. The last refinery turnaround was 2017, therefore any major control installation at either boiler would have to wait until the 2022 or more probably 2027 turnaround. Also, it is likely that the boilers could not be down at the same time, so any significant downtime of the boilers (which any of the proposed controls would require) would have to be staggered between two turnarounds: (1) 2022 and 2027 or (2) 2027 and 2032. However, Phillips 66 does not expect both boilers to be selected in Round 2.

EPA does not provide a time necessary for compliance basis for replacement of the boilers with new RFG-fired units equipped with ULNB/FGR. However, as discussed below with respect to SCR (Selective Catalytic Reduction), such a replacement would require extensive design and commissioning to incorporate new units into the refinery in addition to demolition. On that basis, the timeline would be a minimum of 30 months for design, permitting, financing, etc. through commissioning with additional time needed for demolition.

For SNCR, EPA states in its Cost Control Manual, "Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions."[13] EPA also states in its 2008 Electric Generating Unit (EGU) NO_x Mitigation Strategies Proposed Rule Technical Support Document (TSD) for the Cross State Air Pollution Rule for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) [21], that "SNCR ... requires 12 months from contract award through commissioning." In addition, SNCR would require additional time for "conceptual design, permitting, financing, and bid review." Given that, Phillips 66 is estimating SNCR would require approximately 24 months for design, permitting, financing, etc. through commissioning.

For SCR, as previously mentioned, EPA states in its Cost Control Manual, "In retrofit installations, new ductwork is required to integrate the SCR system with the existing equipment."[17] Because Boiler #1 and #2 are refinery fuel gas-fired units and have negligible particulate emissions, consideration of high-dust SCRs would not be necessary, and the focus would be on either low-dust or tail-end installations (tail-end refers to following all pollution control devices; for Boilers #1 and #2, the options would be essentially the same). "In low-dust SCR systems for utility and industrial boilers, the SCR reactor is located between the outlet duct of the particulate control device and the air heater inlet duct. In tail-end SCR systems for utility and industrial boilers, the ductwork tie-ins are downstream of the FGD system and also require the integration of the flue gas reheating equipment."[17] EPA also states in the TSD for the Cross State Air Pollution Rule for the 2008 Ozone NAAQS [21]· that "The time requirements for an SCR retrofit exceeds 18 months from contract award through commissioning." In addition, SCR would also require additional time for "conceptual design, permitting, financing, and bid review." Given that, Phillips 66 is estimating SCR would require approximately 30 months for design, permitting, financing, etc. through commissioning.

5.3.3 Factor 3 – Energy and Non-air Environmental Impacts

In general, the use of combustion controls for reducing NO_x formation can have a slightly adverse effect on the formation of CO.

SCR and SNCR both present several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

Energy impacts are included in annual operation and maintenance costs.

5.3.4 Factor 4 – Remaining Useful Life of Source

Neither of the boilers are 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.

However, since the boilers are over 70 years old, Phillips 66 is reluctant to spend significant capital, such as SCR/SNCR, on these boilers.

6.0 CONCLUSIONS

A four-factor analysis at the Phillips 66 Billings Refinery was conducted to meet the requirements of "Round 2" to develop a SIP to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, MDEQ requested this analysis from Phillips 66.

The four factors analyzed were based on the MDEQ correspondence and the RHR to determine if there are emission control options at Phillips 66 that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and the remaining useful life of the existing source subject to these requirements.

The four-factor analysis was conducted for NO_x on Boilers #1 and #2 at the Phillips 66 Billings Refinery with additional discussion regarding facility-wide emissions reduction efforts. Phillips 66 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, are apparent in Section 3 of this analysis, as was the lack of correlation between Phillips 66 emissions and visibility in nearby Class I areas (hinted at by the Q/d factor of 4.5, barely above MDEQ's intended action level of 4.0).

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 Boilers #1 and #2 are not necessary to make reasonable progress due to costs and Phillips 66's lack of a measurable impact on any nearby Class I area, particularly in light of recent emissions reductions by Phillips 66 and other regional and state facilities. It is concluded that this facility does not qualify for additional emission controls or limitations based on this analysis.

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APPENDIX A: CORRELATION ANALYSES

Visibility and NOx Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.53	-0.40	0.78	0.76	1	
	P66 NOx	0.04	-0.37	0.52	0.50	0.67	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 NO3	0.28	0.16	0.60	0.57	1	
	P66 NOx	0.00	0.14	0.27	0.25	0.45	1

Visibility and NOx Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.37	-0.07	0.60	0.57	1	
	P66 NOx	0.25	0.01	0.52	0.50	0.39	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 NO3	0.14	0.01	0.36	0.32	1	
	P66 NOx	0.06	0.00	0.27	0.25	0.15	1

Visibility and NOx Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.77	0.23	0.39	0.45	1	
	P66 NOx	0.49	-0.09	0.52	0.44	0.46	1

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 NO3	0.59	0.05	0.15	0.20	1	
	P66 NOx	0.24	0.01	0.27	0.19	0.21	1

Visibility and NOx Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.78	-0.11	0.79	0.84	1	
	P66 NOx	0.34	-0.12	0.52	0.50	0.47	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		
	NO3	0.61	0.01	0.62	0.71	1	
	P66 NOx	0.12	0.01	0.27	0.25	0.22	1

Visibility and NOx Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings NO2*	*Glidepath*	*Anthro NO3*	*P66 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 NO3	0.89	0.70	0.65	0.62	1	
	P66 NOx	0.49	0.25	0.52	0.50	0.53	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 NO3	0.79	0.49	0.42	0.38	1	
	P66 NOx	0.24	0.06	0.27	0.25	0.28	1

Visibility and SO_2 Correlation Calculations

North Absaroka Wilderness Area

	Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
r = Year						
Anthro dV	1					
All dV	0.26	1				
Billings SO2	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	
P66 SO_2	0.65	-0.03	0.82	0.69	0.51	1

	Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
P66 SO_2	0.43	0.00	0.67	0.48	0.26	1

Visibility and SO_2 Correlation Calculations

Yellowstone National Park

	Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
P66 SO_2	0.39	0.01	0.82	0.69	0.22	1

	Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
P66 SO_2	0.15	0.00	0.67	0.48	0.05	1

Visibility and SO_2 Correlation Calculations

UL Bend Wilderness Area

	Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
P66 SO_2	0.61	0.17	0.82	0.66	0.14	1

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	
	P66 SO_2	0.37	0.03	0.67	0.44	0.02	1

Visibility and SO_2 Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
	P66 SO_2	0.62	-0.08	0.82	0.70	0.45	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	
	P66 SO_2	0.38	0.01	0.67	0.49	0.20	1

Visibility and SO_2 Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Billings SO_2*	*Glidepath*	*Anthro SO_4*	*P66 NOx*
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	
	P66 SO_2	0.47	0.37	0.82	0.69	0.37	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	
	P66 SO_2	0.22	0.14	0.67	0.48	0.14	1

APPENDIX B: COST ANALYSES

Replacement Boiler Cost Estimation (per boiler)

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

Where P = $20,000,000 (capital cost, current year)
i = 5.5%
n = 20 years

$$A = \$20M\frac{0.055(1+0.055)^{20}}{(1+0.055)^{20} - 1}$$

Annual disbursement on capital cost = *$1,673,587*

Boiler 1 - SNCR Economic Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial ▼

What type of fuel does the unit burn? Natural Gas ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 120 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 21,105 Btu/lb

What is the estimated actual annual fuel consumption? 22,503,300 scf/year

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous ▼

Enter the sulfur content (%S) = 1.84 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.2745	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1218	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.00	

Plant Elevation 3125 Feet above sea level

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

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

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

Select the reagent used Urea ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	2.40	\$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

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

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.40	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	49,808,102	scf/year	
Actual Annual fuel consumption (Mactual) =		22,503,300	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.45	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3958	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	56	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.32	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	36.26	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at 3125 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	43	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	86	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	9.1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	3.8	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.04	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$520,497 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$814,974 in 2018 dollars
Total Capital Investment (TCI) =	$1,736,113 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$520,497 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) = $814,974 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$86,947 in 2018 dollars
Indirect Annual Costs (IDAC) =	$146,094 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$233,041 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$26,042 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$59,527 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,010 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$368 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2018 dollars
Direct Annual Cost =		$86,947 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$781 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$145,313 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$146,094 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$233,041 per year in 2018 dollars
NOx Removed =	36 tons/year
Cost Effectiveness =	$6,427 per ton of NOx removed in 2018 dollars

Boiler 1 - SCR Economic Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial ▼

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

What type of fuel does the unit burn? Natural Gas ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	120 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	21,105 Btu/lb
What is the estimated actual annual fuel consumption?	22,503,300 scf/year
Enter the net plant heat input rate (NPHR)	8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 3125 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous ▼

Enter the sulfur content (%S) = 1.00 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
○ Method 2
● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	165 days
Number of days the boiler operates (t_{plant})	165 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.2745 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	20 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

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

Select the reagent used Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	49,808,102	scf/year
Actual Annual fuel consumption (Mactual) =		22,503,300	scf/year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.452	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3958	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	85.4	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.14	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	55.69	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.07	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	55,577	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	113.91	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1452	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	487.92	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	58	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	67	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	38	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,700	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	61.70	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$0	in 2018 dollars
Reagent Preparation Cost (RPC) =	\$0	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2018 dollars
Balance of Plant Costs (BPC) =	\$0	in 2018 dollars
Total Capital Investment (TCI) =	\$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = \$0 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = \$0 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = \$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$47,385 in 2018 dollars
Indirect Annual Costs (IDAC) =	$330,777 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$378,163 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,675 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$5,842 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$16,508 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$5,361 in 2018 dollars
Direct Annual Cost =		$47,385 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,424 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$329,353 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$330,777 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$378,163 per year in 2018 dollars
NOx Removed =	56 tons/year
Cost Effectiveness =	$6,791 per ton of NOx removed in 2018 dollars

Boiler 2 - SNCR Economic Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial ▼

What type of fuel does the unit burn? Natural Gas ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 120 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 21,105 Btu/lb

What is the estimated actual annual fuel consumption? 22,416,276 scf/year

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous ▼

Enter the sulfur content (%S) = 1.84 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	3125 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.2745 lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1218 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	2.00	*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).	

Concentration of reagent as stored (C_{stored})	50 Percent
Density of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	50 percent
Number of days reagent is stored ($t_{storage}$)	14 days
Estimated equipment life	20 Years
Select the reagent used	Urea

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Fuel ($Cost_{fuel}$)	2.40 $/MMBtu*	
Reagent ($Cost_{reag}$)	1.66 $/gallon for a 50 percent solution of urea*	
Water ($Cost_{water}$)	0.0042 $/gallon*	
Electricity ($Cost_{elect}$)	0.0676 $/kWh*	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	$/ton	

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.40	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	49,808,102	scf/year	
Actual Annual fuel consumption (Mactual) =		22,416,276	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.45	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3942	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	56	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.32	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	36.12	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at 3125 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	43	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	86	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	9.1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	3.8	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.04	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$520,497 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	\$814,974 in 2018 dollars
Total Capital Investment (TCI) =	\$1,736,113 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$520,497 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$814,974 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$86,711 in 2018 dollars
Indirect Annual Costs (IDAC) =	$146,094 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$232,805 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$26,042 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$59,297 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,006 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$366 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2018 dollars
Direct Annual Cost =		$86,711 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$781 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$145,313 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$146,094 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$232,805 per year in 2018 dollars
NOx Removed =	36 tons/year
Cost Effectiveness =	$6,445 per ton of NOx removed in 2018 dollars

Boiler 2 - SCR Economic Analysis

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial ▼

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

What type of fuel does the unit burn? Natural Gas ▼

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 120 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 21,105 Btu/lb

What is the estimated actual annual fuel consumption? 22,416,276 scf/year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 3125 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous ▼

Enter the sulfur content (%S) = 1.00 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
○ Method 2
● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	164 days
Number of days the boiler operates (t_{plant})	164 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.2745 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	20 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

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

Select the reagent used: Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018 | 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	49,808,102	scf/year	
Actual Annual fuel consumption (Mactual) =		22,416,276	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.450	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3942	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	85.4	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.14	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	55.47	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.07		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	55,577	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	113.91	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.12		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1452	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	487.92	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	58	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	67	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.2	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	52	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	38	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,700	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	61.70	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$0	in 2018 dollars
Reagent Preparation Cost (RPC) =	$0	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$0	in 2018 dollars
Total Capital Investment (TCI) =	$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $0 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $0 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = $0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$47,299 in 2018 dollars
Indirect Annual Costs (IDAC) =	$330,770 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$378,069 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$19,675 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$5,819 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$16,445 in 2018 dollars
Annual Catalyst Replacement Cost =		$5,361 in 2018 dollars
	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	
Direct Annual Cost =		$47,299 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$1,417 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$329,353 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$330,770 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$378,069 per year in 2018 dollars
NOx Removed =	55 tons/year
Cost Effectiveness =	$6,816 per ton of NOx removed in 2018 dollars