2021 Regional Haze Four Factor Initial Control Determination

Facility: Tucson Electric Power, Irvington Generating Station

Air Quality Division
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1 ADEQ Initial Regional Haze Four Factor Control Determination

1.1 ADEQ Initial Control Determination for TEP Irvington

ADEQ's initial decision is to find that in considering the four statutory factors and visibility benefits, it is reasonable to require additional controls on TEP Irvington Generating Station (IGS) during this planning period in order to make reasonable progress toward natural visibility conditions. ADEQ proposes that emission reductions equivalent to the installation of combustion control technologies to reduce nitrogen oxide (NO_X) emissions from Unit 3 at IGS are reasonable for regional haze progress. ADEQ is requesting feedback on an emission limit of 0.10 lb/MMBtu on a 30-day rolling average, which is consistent with the installation of combustion controls. ADEQ is also requesting feedback on an alternative compliance method (see Appendix A), a NOx cap of 2,420 tons over the remaining useful life of Unit 3 in combination with an annual emission limit of 335 tpy.

1.2 ADEQ Control Determination Finalization Timeline

In order to meet the State rulemaking and Regional Haze state implementation plan (SIP) timeline, ADEQ must finalize all four factor analyses as expeditiously as possible. To provide an opportunity for interested stakeholders to review and comment on ADEQ's initial decision prior to finalization, the department intends to post initial decisions on the agency webpage along with the original source submitted four factor analyses. Once ADEQ has reviewed relevant stakeholder comments, the agency will revise its initial decisions if necessary and post final decisions (see Figure 1). ADEQ welcomes feedback on these initial decisions and invites any interested party to send their comments by **April 22, 2021** to:

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Please note that this review and feedback opportunity does not constitute an official state implementation plan or state rulemaking comment period. The agency intends to provide an official 30 day comment period on any proposed SIP or rulemaking action in accordance with Arizona Revised Statutes §§ 41-1023, 49-425, and 49-444.

Figure 1: Four Factor Control Determination Process Map

2 ADEQ Four Factor Analysis

2.1 Summary

TEP completed and submitted a four factor analysis report for NOx emissions from Unit 3 at IGS to ADEQ on March 31, 2020. TEP subsequently submitted an IGS Visibility Modeling Report to ADEQ on October 30, 2020. Additionally, TEP submitted a second supplement on January 18, 2021. The four factor analysis considered the addition of combustion controls such as low-NO_X burners and flue gas recirculation, as well as add on pollution control devices such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). The controls were evaluated for technical feasibility, cost, time necessary for compliance, the remaining useful life of the source, and the non-air quality environmental impacts. ADEQ did not identify any other pollution control devices which could be installed on unit.

ADEQ reviewed the four factor analysis report for completeness and accuracy and modified two variables from TEP's analysis: the life expectancy of an SCR and the interest rate used in the cost calculations. TEP proposed a 20-year life expectancy for installing the SCR based on the life expectancy used in Regional Haze Round 1. ADEQ adjusted the life expectancy to 30 years to be consistent with the updated version of the EPA Cost Control Manual.[1] The cost calculations submitted by TEP utilized an interest rate of 5.25%, which was lowered to 4.75% (the approximate average bank prime interest rate for the last 3 years) to recalculate the control costs submitted in the four-factor analysis.[2] In the initial four-factor analysis TEP inadvertently included the sales tax for the pollution control devices, which is exempt under Arizona Revised Statute (ARS) 43-1081.B; however, this was corrected in TEP's October 2020 supplement.

Considering the four statutory factors and visibility benefits (an optional factor), ADEQ determines that the emission reductions associated with combustion controls for Unit 3 are necessary to make reasonable progress towards natural visibility at Class I areas during this implementation period. ADEQ is requesting feedback on an emission limit of 0.10 lb/MMBtu on a 30-day rolling average, which is consistent with the installation of combustion controls.[3] ADEQ is also requesting feedback on an alternative compliance method, a NOx cap of 2,420 tons over the remaining useful life of Unit 3 in combination with an annual emission limit of 335 tpy.

[1] EPA Cost Manual Section 4, Chapter 2, page 80.

[2] ADEQ calculated the three-year average monthly bank prime rate for 2017-2019 and 2018-2020 as 4.83% and 4.78%, respectively. Based on these averages, ADEQ finds that 4.75% is a representative interest rate.

[3] Please note that 0.1 lb/MMBTU was assumed achievable on a long-term averaging scale for the purposes of the 4-factor analysis which relies on annual emissions. Where a shorter term limit is established, such as the 30-day rolling average presented in this document, additional analyses by ADEQ may need to be performed to ensure this limit is achievable with the increased operational variability assumed at these time-scales.

2.2 Facility Overview

2.2.1 Process Description

The IGS includes two (2) fossil fuel-fired electric utility steam-generating units, designated as Units 3 and 4; two (2) simple cycle combustion turbines; ten reciprocating internal combustion engines; and various ancillary units used to produce electricity for consumers. Unit 3 began operation in 1962 and has a nameplate capacity of 113.6 megawatts (MWe).

Table 1 Historical Emissions for IGS Unit 3

Year	Throughput (MMScf/yr)	NO_x (tpy)	Pollution Control Device
2016	1933.3	185	None
2017	1764.8	189	None
2018	3431.4	392	None

Unit 3 is a tangentially fired boiler capable of burning both natural gas and fuel oil, however, the unit exclusively combusts natural gas. The boiler is not currently subject to any emission limitation for nitrogen oxides (NO_X) and does not have any pollution control devices installed on the unit. Table *2* above reflects the NO_X emissions and fuel usage for Unit 3 from 2016-2018.

2.3 ADEQ Screening Methodology

ADEQ considered processes that underwent evaluation in Regional Haze Round 1, BACT analysis post 2014 or other SIP actions to achieve compliance with the NAAQS as effectively controlled for the purposes of this regional haze analysis[4]. Unit 1 and 2 at IGS were decommissioned due to a prevention of significant deterioration (PSD) permitting action for the installation of 10 reciprocating internal combustion engines (RICE), which was issued on August 8, 2018[5]. Unit 4 at IGS was subject to the best available retrofit technology (BART) analysis during round one of regional haze and elected for a better than BART alternative to combust solely natural gas and landfill gas[6].

Emission processes of PM_{10}, SO_2 and NO_X that were not considered effectively controlled were summed to determine the ton per year emissions (Q) for the facility. If the Q value exceeded 10, ADEQ determined the distance (d) of the facility to the border of the nearest Class I area and calculated the ratio of emissions to distance (Q/d). If the Q/d value exceeded 10, then the

[4] Mercury Air Toxic Standards (MATS) controls were not considered since ADEQ was only focused on NOx, SO2, and PM10 controls.
[5] Pima County Department of Environmental Quality. August 8, 2018. Prevention of Significant Deterioration Air Quality Permit for Tucson Electric Power Irvington Generating Station.
[6] EPA. September 2, 2014. Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan (https://beta.regulations.gov/document/EPA-R09-OAR-2013-0588-0072)

facility was subject to four factor review. The Q/d value for IGS was determined to be 34, making the remaining processes at the facility subject to four factor review.

ADEQ evaluated the top 80% of the emissions not effectively controlled for four factor analysis. Unit 3, Cooling Towers 1-3, and emergency engines were not considered to be effectively controlled, therefore the emissions from each process were added together to determine the total emissions. Next, the emissions from each pollutant and unit were organized in order of decreasing magnitude and the percent of the total emissions were calculated for each pollutant. NO_X emissions from Unit 3 contributed to 90% of the total emissions considered not effectively controlled, therefore, only NO_X emissions from the unit are considered in this analysis.

2.4 Control Overview

2.4.1 Baseline Control Scenario (Projected 2028 Emissions Profile)

To calculate the 2028 projected emissions, ADEQ relied on the emissions inventory data from Pima County. The method used emissions and throughput data from 2016 – 2018 for the 2028 emissions projections. The projected air pollutants include PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, and VOCs.

A scaling factor was determined for each pollutant and emission unit by dividing the annual emissions by the annual throughput for each of the three years. An average of the scaling factor and process throughput were calculated. Emissions for each pollutant were calculated by multiplying the average scaling factor and average throughput for each emission unit. Using this methodology, ADEQ estimated the 2028 emissions of NO_X from the unit to be 251 tons per year.

Table 2 ADEQ 2028 Emissions Projection Methodology

Year	Throughput (MMScf/yr)	NO_x (tpy)	Scaling Factor	Average Scaling Factor	Average Throughput (MMScf/yr)	2028 Projected NO_X Emissions (tpy)
2016	1933.3	185	0.096	0.106	2376.5	251
2017	1764.8	189	0.107			
2018	3431.4	392	0.114			

2.4.2 Evaluated Controls

NO_X emission reductions for natural gas-fired boilers can be accomplished by two general methodologies: pollution preventative measures, such as flue gas recirculation or low-NO_X burners, and add-on pollution control devices. Pollution prevention methodologies include staged combustion or recycling the flue gas into the boiler to reduce the temperature of combustion and lower the concentration of oxygen present in the boiler. A reduction in the combustion temperature prevents the formation of thermal NO_X generated during the combustion process.

Combustion Control Options:

- Low NO_X burners, flue gas recirculation or other combustion controls

Post-Combustion Control Options:

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

2.5 Four Factor Analysis Review

2.5.1 Technical Feasibility

Table 3 below contains a summary of the control technologies considered and whether or not they are technically feasible control options for Unit 3 at IGS.

Table 3 Evaluated Controls and NOx Emission Estimates[1]

Control Option	Technically Feasible (Y/N)	Control Efficiency (%)	Emission Factor (lb/MMBtu)	Heat Input Rate (MMBtu/hr)	NO_X Emission Rate (tpy)
Combustion Controls	Y	52	0.10	277	121
SNCR	Y	18	0.17	277	206
SCR	Y	81	0.04	277	48
Combustion Controls + SCR	Y	90	0.02	277	24

[1] Using a capacity factor of 27%

2.5.1.1 Baseline Scenario:

The 2028 projections estimate the uncontrolled emissions from Unit 3 to be 251 tons per year. A 0% control efficiency was assumed because Unit 3 does not have combustion controls or add-on pollution control devices installed on the unit.

2.5.1.2 Combustion Controls

TEP identified retrofitting Unit 3 with combustion controls such as low-NO_X burners, flue gas recirculation or other combustion controls to reduce NO_X emissions. Combustion controls are regularly installed on natural gas-fired boilers to reduce NO_X emissions and are considered technically feasible.

EPA documents suggest that combustion control technologies have a typical control efficiency ranging from 33% to 50%[7] for pre-NSPS tangentially fired-boilers depending on the technology used. A combination of combustion control technologies could result in emissions reductions between 50-83%[8], however, the Department believes it is unlikely that Unit 3 at IGS could achieve these emissions reductions as the uncontrolled emission rate is approximately half of what is considered in the NEPSIS report. For these reasons, ADEQ agrees with TEP's estimate that retrofitting the unit with combustion controls would result in a NO_X emission rate of 0.10 lb/MMBtu, a 52% reduction in emissions.

2.5.1.3 SNCR

SNCR involves the non-catalytic reduction of NO_X to nitrogen and water. Pollution control devices such as a SNCR are commercially available for installation on natural gas-fired boilers, therefore, this control device is considered technically feasible.

Typical SNCR control efficiencies for tangential-fired boilers range from 25-40%[9], however pre-NSPS boilers do not perform at these levels. EPA documents estimate the control efficiency of these units to be between 16 and 33% with emission rates between 0.2 and 0.25 lb/MMBtu[10]. TEP estimated a NO_X emission rate of 0.17 lb/MMBtu, or a control efficiency of 18%, for the installation of an SNCR in their four factor analysis report. ADEQ agreed an 18% control efficiency was a reasonable estimate for IGS Unit 3.

2.5.1.4 SCR

SCR technologies reduce the amount of NO_X in the exhaust by reacting ammonia or urea with NO_X in the presence of a catalyst. The reaction causes NO_X to decompose into water and elemental nitrogen. SCR is commonly used to control NO_X emissions from natural gas fired boilers and is considered a technically feasible control technology for Unit 3.

SCR technologies installed on pre-NSPS natural-gas boilers have a typical control efficiency of 80-90%[11] with NO_X emission rates between 0.03 to 0.10 lb/MMBtu[12]. TEP estimates the installation of an SCR has the potential to reduce NO_X emissions from Unit 3 to 0.04 lb/MMBtu, a NO_X reduction of 81%. ADEQ agrees that 0.04 lb/MMBtu is reasonable and consistent with EPA documents for these controls.

[7] Environmental Protection Agency. July 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 4: Natural Gas Combustion Sources. https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf
[8] US Environmental Protection Agency Office of Air and Radiation, Office of Air Quality Planning and Standards. March 1994. Alternative Control Technologies Document NO_X Emissions from Utility Boilers. https://www3.epa.gov/ttn/catc/dir1/utboiler.pdf
[9] Environmental Protection Agency. July 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 4: Natural Gas Combustion Sources. https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf
[10] US Environmental Protection Agency Office of Air and Radiation, Office of Air Quality Planning and Standards. March 1994. Alternative Control Technologies Document NO_X Emissions from Utility Boilers. https://www3.epa.gov/ttn/catc/dir1/utboiler.pdf
[11] See Reference 6.
[12] See Reference 7.

2.5.1.5 SCR and Combustion Controls

SCR coupled with combustion control technologies is a common control technology used to control NO_X emissions from natural gas-fired utility boilers and is considered technically feasible. A SCR operated with combustion controls has the highest control efficiency for reducing NO_X emissions with a potential to reduce emissions by up to 93%[13]. TEP proposed a NO_X reduction of 90% with the use of SCR and combustion controls. The resulting emissions from Unit 3 would result in an annual emission rate of 24 tons per year or 0.02 lb/MMBtu. Since the emission rate is within the range suggested by EPA documentation, ADEQ agrees that this emission rate is acceptable.

2.5.2 Cost of Compliance

Table 4 below depicts a summary of the cost estimates for the control measures considered in this four factor analysis.

Table 4 Control Option Cost Effectiveness

Control option	Capital cost	Annualized capital cost	Annual operating & maintenance cost	Total annual cost ($/yr)	Emission reduction (tpy)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Combustion controls	$3,408,000	$267,700	$79,753	$347,453	130	$2,673	n/a
SNCR[1]	$4,033,735	n/a	n/a	n/a	45	n/a	n/a
SCR[2]	$14,642,790	$925,424	$252,837	$1,178,261	202	$5,823	$11,484
Combustion Controls & SCR	$18,050,613	$1,193,113	$316,797	$1,509,910	227	$6,654	$11,992

[1]SNCR is more expensive and less effective than combustion controls and was not considered any further in the 4 factor analysis since combustion controls are considered cost effective.
[2]SCR was calculated using the incremental cost effectiveness since combustion controls are cost effective.

The cost effectiveness of SCR and SNCR were calculated using EPA's cost calculators. The combustion control retrofit capital and operating costs were calculated based on the Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 9: Five-Factor Reasonable Progress (RP) Analyses for TEP Springerville, APS Cholla, TEP Sundt, CalPortland Cement and Phoenix Cement Plants report by Andover technologies and the underlying calculations[14]. The

[13] US Environmental Protection Agency Office of Air and Radiation, Office of Air Quality Planning and Standards. March 1994. Alternative Control Technologies Document NO_X Emissions from Utility Boilers. https://www3.epa.gov/ttn/catc/dir1/utboiler.pdf

[14] Report: www.regulations.gov/contentStreamer?documentId=EPA-R09-OAR-2013-0588-0006&attachmentNumber=4&contentType=pdf
Calculations: http://www.regulations.gov/contentStreamer?documentId=EPA-R09-OAR-2013-0588-0007&attachmentNumber=48&contentType=excel12book

remaining life of the control was set at 30 years for SCR, and 20 years for SNCR and combustion controls.

Combustion controls were considered cost effective on a dollar per ton basis and the incremental cost-effectiveness of SCR was considered high.

2.5.3 Time Necessary for Compliance

As will be discussed in more details in Section 2.5.6, the only cost effective control measure determined by ADEQ is the installation of combustion controls. ADEQ proposes the compliance deadline should be (three years after promulgation of a final, non-reviewable SIP approval regulation.

2.5.4 Remaining Useful Life of Source

TEP estimates the remaining useful life of Unit 3 would not exceed the life of the controls installed. However, without an enforceable requirement for shutdown, ADEQ used thirty years as the useful life of the SCR based on EPA Cost Manual and twenty years as the useful life for the combustion controls.

2.5.5 Visibility Modeling

TEP submitted Irvington Generating Station Visibility Modeling Report to ADEQ on October 30, 2020. The visibility modeling was performed by Ramboll US Consulting, Inc. (Ramboll) with the Comprehensive Air-quality Model with extensions (CAMx) photochemical grid model. Two emission scenarios for Unit 3 were modeled, 2028 base case scenario (251 tpy for NOx) and 2028 control scenario (121 tpy for NOx using the combustion controls).

The modeled results indicate that the contributions from Unit 3 in terms of light extinction are highest at Saguaro Wilderness Area (Saguaro), the nearest Class I Area to the IGS. Unit 3 without additional controls contributed 0.00995 Mm^{-1} of light extinction on the 20% most impaired days at Saguaro.[15] Comparatively, the contribution with the combustion controls was 0.00685 Mm^{-1}. Therefore, the emission reduction of 130 tpy for NOx resulting from the combustions controls would yield a predicted visibility improvement of 0.0031 Mm^{-1}. Additionally, the modeling report calculates the relative contribution of the 2028 base emissions to total visibility impairment. Unit 3 contributes 0.033% to the total visibility impairment in terms of light extinction (30.18 Mm^{-1}) at Saguaro on the 20% most impaired days. By excluding the Rayleigh scattering (10 Mm^{-1}) component from the total light extinction,

[15] A key aspect of regional haze planning is the tracking of progress. In EPA's 2017 Regional Haze Rule, EPA altered progress tracking in that they "revised the way in which some days during each year are to be selected as the 20 percent most impaired days and then used for purposes of tracking progress towards natural visibility conditions. This change focuses attention on days when anthropogenic emissions impair visibility instead of days when wildfires and natural dust storms are the greatest contributors to reduced visibility." (EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 2019). Therefore, ADEQ is reporting modeling results with a focus on the "most impaired days".

ADEQ estimated that Unit 3 contributed approximately 0.05% to the aerosol light extinction at Saguaro on the 20% most impaired days.

ADEQ also reviewed the modeled results of the 2028 emissions scenario (2028OTBa2) from the Western Regional Air Partnership (WRAP)/Western Air Quality Study (WAQS) Regional Haze photochemical grid modeling platform[16]. The aerosol light extinction is 19.29 Mm^{-1} at Saguaro on the most impaired days. The contribution from ammonium nitrate is approximately 7%, or 1.368 Mm^{-1}. A sensitivity analysis also indicates that CAMx tends to underestimate the contribution from ammonium nitrate.[17] ADEQ reviewed the 2014-2018 Interagency Monitoring of Protected Visual Environments (IMPROVE) data and found that ammonium nitrate typically accounts for approximately 10% of the aerosol light extinction at Saguaro on the most impaired days[18].

2.5.6 Determining Control Measures that are Necessary to Make Reasonable Progress

A state must consider the four statutory factors to determine what control measures are necessary to make reasonable progress. Per Guidance on Regional Haze State Implementation Plans for the second implementation period, a state has the flexibility to select or not select to take the visibility impacts of a source and the visibility benefits of feasible control options into account.

To help make a determination, ADEQ reviewed Best Available Retrofit Technology (BART) and Reasonable Progress (RP) determinations during the first regional haze second planning period. EPA and States heavily weighed two factors for their determinations: cost-effectiveness (average and incremental) in conjunction with visibility improvements in Class I areas. For the most expensive controls such as SCR, significant weightage was apportioned to visibility benefits. Based on the data ADEQ gathered, EPA and several States found SCR reasonable when the cost-effectiveness was less than 5,000 $/ton and the control achieved a visibility improvement of 0.5 deciviews (dv) or above. In contrast, less weight was put on visibility benefits for less expensive control options. For example, multiple SNCR cases were found to be reasonable in which the SNCR control only resulted in approximately 0.2 dv improvement at the maximum Class I Areas. Colorado additionally found and EPA approved a LNB+SOFA case with a cost-effectiveness of 3,200 $/ton despite a resulting visibility improvement of 0.08 dv (Colorado Energy Nations Company Boiler 4).

These reference values on visibility benefits above are not very useful in this round determinations due to the fundamental differences in modeling visibility impacts between two modeling systems. CALPUFF was predominantly used in the first implementation period while a full photochemical grid model (PGM) is exclusively used in the second implementation period. In the BART analysis for Coronado Generating Station, ADEQ found that modeled visibility

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16 https://views.cira.colostate.edu/tssv2/
17 https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
18 http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

impacts using CAMx (a PGM) were much lower in magnitude than modeled visibility values with CALPUFF. Additionally, deciview units were typically used in BART and RP analyses in the first implementation period. However, EPA recommends that visibility benefits of a control measure be expressed in units of light extinction rather than deciviews in the second implementation period. Finally, as the EPA states, because regional haze results from a multitude of sources over a broad geographic area, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement. Because of the above reasons, establishing a visibility benefit threshold to evaluate control measures appears to be infeasible.

Based on the EPA's decisions during the first implementation period and the EPA's Guidance for the second implementation period, ADEQ is using an average cost-effectiveness of 4,000 $/ton as a threshold to determine whether it is necessary to consider the visibility benefits or not for a control measure decision. Specifically, any controls having an average cost-effectiveness of 4,000 $/ton or lower are deemed to be cost effective unless there are compelling or extraordinary circumstances. If the average cost-effectiveness for a control is more than 4,000 $/ton, the Department will consider the balance between the cost of compliance and the visibility benefits to make a decision on a case-by-case basis.

2.5.6.1 Combustions Controls

As shown in Table 4, the average cost-effectiveness for combustion controls is 2,673 $/ton, which is significantly lower than the threshold of 4,000 $/ton as ADEQ established. Although the IGS Modeling Report indicates that the visibility benefits from the combustion controls are small, it is more compelling to conclude that the combustion controls are cost effective because the average cost-effectiveness number is well within the range ADEQ considers reasonable. Considering that IGS is the largest industrial source near Saguaro and ammonium nitrate accounts for approximately 10% of the aerosol light extinction at Saguaro on the most impaired days, ADEQ determines that it is reasonable to require TEP to add the combustion controls to reduce the NOx emissions at Unit 3.

2.5.6.2 SCR

The average cost-effectiveness for SCR is $5,823 $/ton, which falls in a range that may be cost-effective, depending on additional considerations. However, the SCR control option has an incremental cost-effectiveness of $11,484/tons (over the combustion controls), which is cost excessive. It also should be addressed that the average and incremental cost-effectiveness are estimated using a remaining useful life of 30 years for the control device. However, it is expected that the remaining useful life for Unit 3 would be shorter than 30 years. In the letter to ADEQ dated October 30, 2020, TEP indicated that the unit was expected to retire permanently by 2032. The average and incremental cost-effectiveness would be higher if using a shorter remaining useful life such as 20 years as opposed to a 30-year remaining useful life. However, given that a shut-down is not enforceable through rule or permit, ADEQ continues to rely on a 30 year useful life for this determination.

ADEQ also examined the visibility benefits due from SCR. Because TEP did not directly model the SCR control scenario in the IGS Modeling Report, ADEQ assumed that SCR would remove the entire baseline emissions of 250 tpy instead of 202 tpy. With this assumption, SCR would yield a total visibility improvement of 0.007 Mm^{-1} and 0.016 Mm^{-1} over 25 Class I Areas on the best 20% days and the 20% most impaired days, respectively. Among the 25 Class I Areas, the maximum visibility benefit occurs at Saguaro but only accounts for approximately 0.03% of the total light extinction at Saguaro on the 20% most impaired days. As shown in Table 4, the total annual cost of SCR at Unit 3 is $1.18 million. Therefore, the costs of SCR in terms of dollar per light extinction units ($/$Mm^{-1}$) are $168 and $73 million/$Mm^{-1}$ for the best 20% days and the 20% most impaired days, respectively. ADEQ determines that the visibility benefits from SCR are small and the cost in terms of $/Mm is large.

Based on the average cost-effectiveness, the excessive incremental cost-effectiveness, and the correspondingly small visibility benefits, ADEQ rejects SCR as a reasonable control.

2.6 Emission Limits

Based on the four-factor analysis as discussed above, ADEQ determines that the combustion controls for Unit 3 are necessary to make reasonable progress. Specifically, ADEQ is requesting feedback on an emission limit of 0.10 lb/MMBtu on a 30-day rolling average, which is consistent with the combustion controls.[19] ADEQ is also requesting feedback on an alternative plan, a NOx cap of 2,420 tons over the remaining useful life of Unit 3 in combination with an annual emission of 335 tpy. For detailed discussions, please see Appendix A.

TEP must select one option no later than one year after the SIP approval. TEP must comply with the selected option no later three years after the SIP approval.

[19] Please note that 0.1 lb/MMBTU was assumed achievable on a long-term averaging scale for the purposes of the 4-factor analysis which relies on annual emissions. Where a shorter term limit is established, such as the 30-day rolling average presented in this document, additional analyses by ADEQ may need to be performed to ensure this limit is achievable with the increased operational variability assumed at these time-scales.

3 Appendix A: Alternative Control Scenario

Based on the four factor analyses performed for IGS Unit 3, ADEQ is requesting feedback on the determination that enhanced combustion controls are reasonable for Round 2 Regional Haze planning. The installation of these controls will result in an approximate 52% reduction of NO_x emissions from Unit 3. While these emissions reductions are substantial, ADEQ is also soliciting stakeholder feedback on alternative control limits that would result in increased long-term visibility improvement through the eventual shutdown of Unit 3. These visibility enhancements would be achieved through the application of a remaining useful life emission cap for IGS Unit 3 to ensure the eventual shutdown of the unit while also minimizing shorter-term visibility impacts through the additional implementation of an annual emission cap for the unit.

ADEQ presents the dual emission cap, the historical precedence for this approach, and a comparative analysis of the dual emission cap and the installation of enhanced combustion controls in the sections below. ADEQ welcomes stakeholder feedback on this approach as an alternative compliance method to the installation of enhanced combustion controls.

3.1 Dual Emission Cap Proposal

ADEQ is proposing the following emission caps as an alternative compliance method to the combustion controls outlined in the four factor analysis previously presented. The proposal includes a combination of an annual emission limit (tpy) and a cumulative emission limit (tons) over the remaining useful life (RUL) of Unit 3:

1. 2,420 tons of NO_x over the RUL and
2. 335 tons of NO_x per year, on a rolling 12-month basis

This approach would limit the remaining life of the unit through the RUL while providing a shorter-term annual limit to reduce the risk of visibility degradation while the unit is still in operation. The method by which these limits were established is presented below.

3.1.1 RUL emission cap development

ADEQ established the 2,420 tons of NO_x RUL emission cap by relying on the results of the four factor analysis for combustion controls. Average baseline emissions without controls in the four factor analysis was determined to be 251 tpy of NO_x from Unit 3. ADEQ estimates the post-combustion control annual emission rate to be 121 tpy. Assuming a 20 year RUL for the unit, ADEQ estimates that an equivalent RUL emission cap would be 2,420 tons:

$$121\text{tpy} * 20\text{years RUL} = 2{,}420 \text{ tons NOx for RUL}$$

This would achieve identical emissions reductions (2,600 tons over a 20-year lifespan) to the installation of the enhanced combustion controls. Additionally, it would ensure the unit would cease operation once this cap is met.

3.1.2 Annual emission cap development

While the application of the RUL emission cap ensures enhanced visibility in the future, ADEQ must also protect visibility while the unit is still in operation. As such, ADEQ is proposing to additionally require an annual emission limit for IGS Unit 3. This emissions limit will ensure visibility does not deteriorate as compared to baseline conditions.

While the average annual emissions during the baseline period was 251 tpy, annual NO_x emissions from Unit 3 ranged from 185 – 392 tpy between 2016 and 2018. As such, ADEQ recognizes that there is significant variability in operation of Unit 3, which is likely to continue into the future. Given this variability, ADEQ is proposing an annual emission limit of 335 tpy NO_x from Unit 3. This value was determined through the following methodology:

1. Calculate the average of the three highest emission rate factors (lb/MMBTU) between 2015 and 2019.
2. Calculate the average of the three highest heat inputs (MMBTU) between 2015 and 2019.
3. Calculate the product of the average max emission rate factor and average max heat input.
4. Convert to tpy

Based on the steps outlined above, ADEQ estimated an annual NO_x emission cap of 335 tpy utilizing the information provided in Table 5. ADEQ is soliciting feedback on whether this emission cap will provide sufficient flexibility to the source for normal variations in operations and demand, while also protecting visibility from deterioration as compared to the baseline.

Table 5: Annual Emission Cap Estimation for IGS Unit 3

Scenario	Emission Rate Factor (lb/MMBTU)	Heat Input (MMBTU)	Annual NO_x (tpy)
Average of three highest emission rate factors[1] * Average of three highest heat inputs[2]	0.1958	3,422,378	335

[1] The years with the three highest emission rate factors were 2017, 2018, and 2019

[2] The years with the three highest heat inputs were 2016, 2018, and 2019

3.2 Emission Cap Legal and Historical Justification

Under the Federal Regional Haze Rule (RHR) each state must submit a long-term strategy that includes “the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress”.[20] When establishing enforceable emission limits EPA’s final regional haze guidance specifies that limits must also include “provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.”[21] For establishing emission limit averaging times the guidance outlines that both throughput and mass based emission limits are permissible under the RHR and point to a “cap on 30-operating day mass emissions” as an example of such a mass based limit.[22] While the guidance identifies 30 days as being a common averaging time, nothing in the RHR or guidance precludes the use of a longer averaging time (e.g. 12-month rolling average tpy). In the first regional haze implementation period EPA adopted 12-month rolling average tpy limits for both Phoenix Cement in Arizona and HELCO in Hawaii as appropriate averaging times for reasonable progress determinations.[23] In the case of Phoenix Cement, EPA further clarified its position in responding to an adverse comment on the form of the limit by stating “the RHR does not preclude the establishment of an annual emission limit for the purpose of achieving emissions reductions for reasonable progress.”[24]

Based on the flexibility of the RHR in establishing emission limit averaging times and on the historical use of annual emission caps during the first implementation period, ADEQ is soliciting stakeholder feedback on the herein proposed dual emission cap limits to provide TEP with an alternative compliance method that does not require the application of a specific control technology.

3.3 Dual Emission Cap & Combustion Control Comparison

Photochemical visibility modeling analyses have not been performed to compare the visibility impacts of the dual emission cap to that of the enhanced combustion control installation. As such, ADEQ is performing a comparative analysis of the two control scenarios by analyzing potential emission trends.

Given the flexibility associated with the emission cap approach, ADEQ is presenting 3 scenarios by which the emission trends could be realized under this scenario. The results are presented in Figure 2. These three scenarios represent the following:

[20] *See* 40 CFR 51.308(f)(2)
[21] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. U.S. Environmental Protection Agency, EPA-457/B-19-003, August 2019. Page 42.
[22] *Id*. at 44.
[23] *See* 79 FR 52420, 52460 (September 3, 2014) and 77 FR 61478, 61492. (October 9, 2012)
[24] *See* 79 FR 52420, 52460 (September 3, 2014)

1. Cap Scenario 1: TEP maximizes the annual emissions cap (335 tpy) until RUL cap is reached
2. Cap Scenario 2: TEP operates Unit 3 at baseline average emissions (251 tpy) until RUL cap is reached
3. Cap Scenario 3: TEP operates Unit 3 at an annual emission rate equivalent to combustion controlled emissions (121 tpy) until RUL cap is reached

While these only represent 3 possible scenarios, they provide for a good comparative analysis between the possible NO_x emissions scenarios for Unit 3.

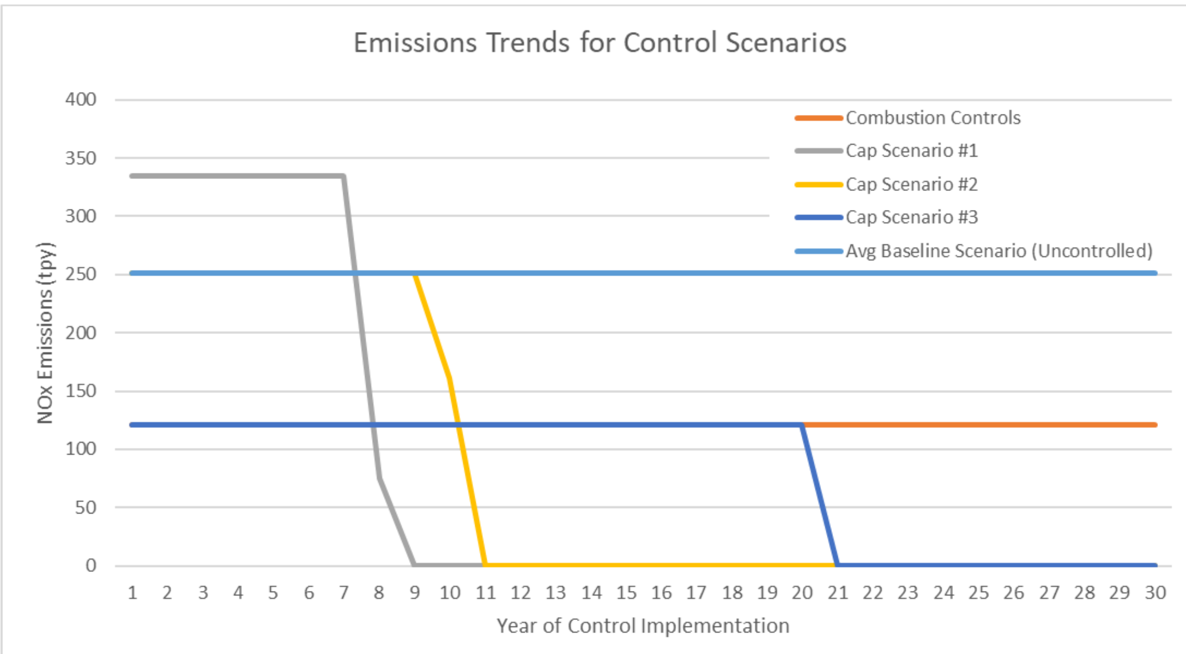

Figure 2: Comparison of emissions trends between the average baseline scenario, the installation of enhanced combustion controls, and three scenarios for the emission cap proposal

Additionally, for this comparison, ADEQ has assumed that the combustion controls will result in an annual emission rate of 121 tpy (the equivalent of a 52% reduction of the baseline emissions, 251 tpy). This may be an over or under assumption of future annual emissions and would ultimately be dependent on the actual NO_x emissions rate achieved by the enhanced combustion controls and heat input.

Finally, ADEQ presents in Figure 2 the scenario of the uncontrolled average baseline emissions continuing to 2030 for comparison purposes. As for the combustion control scenario, this may be an over or under assumption of future annual emissions and would ultimately be dependent on the actual NO_x emissions rate achieved and the heat input.

Under the assumed scenarios described above, ADEQ presents multiple scenarios for the emission cap approach to show a range of possible outcomes that could be realized. Under Cap Scenario #1, Unit 3 could produce higher emissions as compared to the baseline average and the combustion control scenario for the first 7 years of control implementation. At year 8, the Cap Scenario #1 would fall below the annual emissions of both the average baseline scenario and the combustion controls scenario. At year 9 and beyond, Cap scenario #1 would not experience any additional NO_x emissions from Unit 3 as the RUL cap would be met.

Under Cap Scenario #2, the Unit 3 annual NO_x emissions would equal those of the Average Uncontrolled Baseline Scenario until year 10. At this point, the annual emissions would fall to 161 tpy and would reach the RUL cap. From year 11 onward, Unit 3 emissions would be zero.

Finally, under Cap Scenario #3, the Unit 3 annual NO_x emissions would equal those of the combustion control scenario for 20 years. At this point, the RUL cap would be reached and the unit would not be allowed to emit any additional NO_x.

It is highly unlikely that any of the presented scenarios would be realized in operation but they do represent a range of possibilities. Similarly, the unit could operate past 20 years, but would have to operate at a lower average annual emission rate than would be achieved through combustion control installation.

ADEQ recognizes that the approach of the dual emissions cap may not achieve the same short-term emissions reductions realized by the installation of enhanced combustion controls; however, it does offer long-term benefits in a form permissible under the RHR which could help ADEQ reach natural conditions by 2064 and is therefore potentially better aligned with the ultimate goals of the Regional Haze program.