# 2021 Regional Haze Four Factor Initial Control Determination

## Facility: Tucson Electric Power Springerville Generating Station

*Air Quality Division*
*April 13, 2021*

# Table of Contents


Table of Contents ..... ii
List of Figures ..... iii
List of Tables ..... iii
1 ADEQ Initial Regional Haze Four Factor Control Determination ..... 1
1.1 ADEQ Initial Control Determination for TEP Springerville ..... 1
1.2 ADEQ Control Determination Finalization Timeline ..... 1
2 ADEQ Four Factor Analysis ..... 2
2.1 Summary ..... 2
2.2 Facility Overview ..... 3
2.2.1 Process Description ..... 3
2.2.2 Affected Class I Area(s) ..... 5
2.2.3 Baseline Emission Calculations ..... 5
2.3 ADEQ Screening Methodology ..... 6
2.4 Proposed Control Methodology ..... 7
2.4.1 Baseline Control Scenario (Projected 2028 Emissions Profile) ..... 7
2.4.2 Evaluated Controls and Emission Estimates ..... 8
2.5 Four Factor Analysis Review for $PM_{10}$ Emissions ..... 10
2.5.1 Technical Feasibility ..... 10
2.6 Four Factor Analysis Review for $NO_X$ Emissions ..... 11
2.6.1 Technical Feasibility ..... 11
2.6.2 Cost of Compliance ..... 13
2.6.3 Visibility Impact ..... 13
2.6.4 Determining Control Measures that are Necessary to Make Reasonable Progress ..... 14
2.7 Four Factor Analysis Review for $SO_2$ Emissions ..... 16
2.7.1 Technical Feasibility ..... 16
2.7.2 Cost of Compliance ..... 20
2.7.3 Time Necessary for Compliance ..... 23
2.7.4 Energy and Non-Air Quality Impacts ..... 23
2.7.5 Remaining Useful Life of Source ..... 23

2.7.6 Visibility Impact .......... 23
2.7.7 Determining Control Measures that are Necessary to Make Reasonable Progress .......... 24
2.7.8 Emission Limits .......... 26

# List of Figures

Figure 1: Four Factor Control Determination Process Map .......... 1

# List of Tables

Table 1: Proposed Emission Limits .......... 2
Table 2 Pollution Control Devices at SGS .......... 4
Table 3 Current Emission Limits .......... 4
Table 4 Historical Emissions .......... 5
Table 5 Top 80% of emissions at SGS based on 2018 emissions .......... 6
Table 6 Processes included in SGS 4FA based on 2018 emissions .......... 7
Table 7: TEP Springerville 2028 Projections .......... 8
Table 8 Evaluated $PM_{10}$ Controls .......... 10
Table 9 Evaluated $NO_X$ Controls .......... 11
Table 10 $NO_X$ Control Option Cost Effectiveness .......... 13
Table 11 Visibility Improvements from NOx Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018 .......... 14
Table 12 Evaluated $SO_2$ Controls .......... 16
Table 13 $SO_2$ Control Option Cost Effectiveness for 20 Years .......... 22
Table 14 $SO_2$ Control Option Cost Effectiveness for 30 Years .......... 22
Table 15 Visibility Improvements from $SO_2$ Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018 .......... 24
Table 16 Ammonium Sulfate Extinction from U.S. Anthropogenic Sources .......... 25
Table 17 Annual Capped Emissions Limit for Unit 1 and Unit 2 .......... 27

# 1 ADEQ Initial Regional Haze Four Factor Control Determination

## 1.1 ADEQ Initial Control Determination for TEP Springerville

ADEQ's initial decision is to find that it is reasonable to require additional controls on TEP Springerville during this planning period in order to make reasonable progress toward natural visibility conditions. ADEQ proposes, as reasonable controls, additional sulfur dioxide ($SO_2$) controls for Unit 1 and Unit 2 by upgrading the current spray dry absorbers (SDA) or equivalent $SO_2$ emission reductions from Units 1 and 2 achieved through other means. ADEQ additionally proposes that no new emission reductions are reasonable for Units 3 and 4.

## 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 **May 14, 2021** to:

**Ryan Templeton, P.E.**
Senior Environmental Engineer
Templeton.Ryan@azdeq.gov

**Elias Toon, E.P.I.**
Environmental Science Specialist
Toon.elias@azdeq.gov

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

ADEQ is proposing additional sulfur dioxide ($SO_2$) emission limitations for Unit 1 and Unit 2 based on updating the current spray dry absorbers (SDA). TEP contracted Sargent and Lundy (S&L) to evaluate potential upgrades for the units, which concluded updating the SDA could result in emissions reductions of 36%. Based on S&L's analysis, ADEQ is proposing the following combined emission limitations for Unit 1 and Unit 2:

**Table 1: Proposed Emission Limits**

| Unit | Pollutant | Limit | Averaging Period | Corresponding Control Technology |
|---|---|---|---|---|
| **Unit 1 & Unit 2** | $SO_2$ | 17.1 tpd | 30-day rolling average | Upgraded spray dry absorber (SDA) |
| **Unit 1 & Unit 2** | $SO_2$ | 3,729 tpy | 12-month rolling average | Upgraded spray dry absorber (SDA) |

TEP completed and submitted separate four factor analysis reports for SGS Units 1, SGS Unit 2, and another for Unit 3 and 4, to the Department on March 31, 2020. TEP supplied supplemental submittals on November 6, 2020 and December 18, 2020. The four factor analyses considered emissions of nitrogen oxides ($NO_X$), $SO_2$, and particulate matter less than 10 microns ($PM_{10}$) and associated control technologies. The controls were evaluated for technical feasibility, cost of compliance, time necessary for compliance, energy and non-air environmental impacts, and the remaining useful life of the source. In addition to the four factors, the TEP reports assess the visibility impacts of SGS and the visibility benefits of feasible control options.

ADEQ reviewed TEP's four factor analysis report for completeness and accuracy and noted some assumptions which have been updated in subsequent submittals or in this document. These changes included the life expectancy for SCR and $SO_2$ controls, the interest rate used in the cost calculations, and a more thorough review of Wet Flue Gas Desulfurization (wet FGD) and Circulating Dry Scrubbers (CDS). TEP proposed a life expectancy of 20 years for an SCR on Unit 1 and 2, however the EPA Cost Control Manual recommends a life expectancy of at least 30 years for SCRs installed at electricity generating units and 20 to 30 years for $SO_2$ controls[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

[1] EPA Cost Manual Section 4, Chapter 2and EPA Cost control Manual Section 5, Chapter 1.

submitted in the four-factor analysis.[2] In their 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. This was corrected in a supplemental submittal to ADEQ.

## 2.2 Facility Overview

### 2.2.1 Process Description

Springerville Generating Station (SGS) comprises four coal-fired electric generating units with a combined, nominal, net generating capacity of 1,620 megawatts (MWe). Units 1 and 2 at SGS are owned and operated by Tucson Electric Power Company (TEP). Unit 3 is owned by Tri-State Generation and Transmission Association, Inc., and Unit 4 is owned by the Salt River Project Agricultural Improvement and Power District (SRP). All units are operated by TEP.

Unit 1 and Unit 2 boilers are tangentially-fired units, each with a nameplate capacity of 424.8 megawatts. Units 1 and 2 combust subbituminous coal from El Segundo mine, which has a sulfur content of approximately 1% by weight[3]. Unit 3 and Unit 4 boilers are dry bottom wall-fired units each with a nameplate capacity of 458.1 MWe and primarily fire Powder River basin (PRB) coal and other low-sulfur coals which have a typical sulfur content of about 0.2% by weight[4].

In addition to controls in place to meet the requirements of other programs such as Mercury and Air Toxics Standards (MATS) and new source performance standards (NSPS), all four units at SGS are equipped with pollution control devices to control emissions of particulate matter less than 10 microns ($PM_{10}$), nitrogen oxides ($NO_X$), and $SO_2$, which have been summarized in Table 2 below.

[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] US Energy Information Administration. Coal shipment sulfur content: El Segundo (2902257) to Springerville (8223): Subbituminous : quarterly. https://www.eia.gov/opendata/qb.php?category=773545&sdid=COAL.SHIPMENT_SULFUR.2902257-8223-SUB.Q

[4] US Energy Information Administration. Coal shipment sulfur content: North Antelope Rochelle Mine (4801353) to Springerville (8223) : Subbituminous : quarterly. https://www.eia.gov/opendata/qb.php?category=773545&sdid=COAL.SHIPMENT_SULFUR.4801353-8223-SUB.Q

**Table 2 Pollution Control Devices at SGS**[5]

| | **Units 1 and 2** | **Units 3 and 4** |
|---|---|---|
| $PM_{10}$ | Baghouse | Baghouse |
| $NO_X$ | Low $NO_X$ burners and overfire air (OFA) | Low $NO_X$ burners, OFA, and selective catalytic reduction (SCR) |
| $SO_2$ | Spray dry absorbers (SDA) | Spray dry absorbers (SDA) |

Unit 1 and Unit 2 began construction in 1978 and commenced operations in 1985 and 1990, respectively. The boilers are subject to NSPS Subpart D since the capacity of each is greater than 25 MW and commenced construction after 1971. EPA issued an approval to construct with emission limits more stringent than the federal standards; therefore, these limits have been incorporated into the permit.

A prevention of significant deterioration (PSD) permit for the construction and operation of Unit 3 and Unit 4 was issued in 2002. During the permitting action, TEP accepted combined emission limits for $SO_2$ and $NO_X$ for all four units as well as limits for particulate matter (PM) for Units 3 and 4. Because the units are greater than 73 MW and commenced construction after 1978, both units are subject to NSPS Subpart Da. All four units are subject to the MATS rule for coal-fired boilers, thus the emission limits from this subpart are also listed in the air quality permit. A summary of $NO_x$, $SO_2$, and PM emission limits for Units 1-4 can be found in Table 3 below.

**Table 3 Current Emission Limits**

| Emission Source | Pollutant | Emission Limits |
|---|---|---|
| **Unit 1 & Unit 2** | $NO_X$ | 0.22 lb/MMBtu (12-month rolling average); and<br>0.697 lb/MMBtu (avg. of three 1-hr tests) |
| **Unit 1 & Unit 2** | $SO_2$ | 0.27 lb/MMBtu (12-month rolling average);<br>0.690 lb/MMBtu (average of three 1-hr tests);<br>85% reduction (90-day rolling average); and<br>0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit) |
| **Unit 1 & Unit 2** | $PM/PM_{10}$ | 0.034 lb/MMBtu (avg of three 1-hr tests);<br>0.03 lb/MMBtu; and<br>0.3 lb/MWh or 0.03 lb/MMBtu (total PM) |
| **Unit 3** | $NO_X$ | 1.6 lb/MWh (30-day rolling average) |

[5] This list is not inclusive of all controls at SGS. Given that ADEQ is targeting $NO_x$, $SO_2$, and $PM_{10}$ pollution controls, we have chosen to exclude controls required for programs such as the Mercury Air Toxics Standards (MATS).

| Emission Source | Pollutant | Emission Limits |
|---|---|---|
| **Unit 3** | $SO_2$ | 1.2 lb/MMBtu and a 90% reduction; Or 70% reduction when emissions are <0.6 lb/MMBtu; and 0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit) |
| **Unit 3 & Unit 4** | PM | 0.015 lb/MMBtu (excludes condensable PM); and 0.3 lb/MWh or 0.03 lb/MMBtu (total PM) |
| **Unit 3 & Unit 4** | $PM_{10}$ | 0.055 lb/MMBtu (includes filterable and condensable $PM_{10}$) |
| **Unit 4** | $NO_X$ | 1.0 lb/MWh (30-day rolling average) |
| **Unit 4** | $SO_2$ | 1.4 lb/MWh or 95% reduction; and 0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit) |
| **Unit 4** | PM | 0.14 lb/MWh or 0.15 lb/MMBtu; Or 0.03 lb/MMBtu and 99.9% reduction |
| Combined emission limit | $NO_X$ | 9,600 tpy (calendar year and rolling 12-month total) |
| Combined emission limit | $SO_2$ | 10,800 tpy (calendar year and rolling 12-month total); and 8,448 lb/hr (3-hr rolling basis) |

### 2.2.2 Affected Class I Area(s)

There are five Class I areas within 200 km of TEP Springerville. These areas from nearest to furthest are Mount Baldy Wilderness, Petrified National Forest Park, Gila Wilderness, Sierra Ancha Wilderness and Tonto National Forest Wilderness.

### 2.2.3 Baseline Emission Calculations

ADEQ generally established baseline emissions for all sources using emissions from 2016-2018. TEP SGS Unit 1, however, was shut down for four months in 2017 resulting in a lower throughput that year than in normal years. Therefore, baseline emissions were from years 2016, 2018 and 2019 for TEP SGS Units 1 and 2, to ensure that the baseline emissions were representative of normal operations. Table 4 below shows the heat inputs, coal throughputs, and annual emissions of $NO_X$, $SO_2$ and $PM_{10}$ from 2016, 2018 and 2019 for Unit 1 and Unit 2, and 2016-2018 for Units 3 and 4.

**Table 4 Historical Emissions**

| Year | Heat Input (MMBtu/yr) | Coal Throughput (tpy) | $NO_X$ (tpy) | $SO_2$ (tpy) | $PM_{10}$ (tpy) |
|---|---|---|---|---|---|
| | | | **Unit 1** | | |
| **2016** | 21,012,116 | 1,202,152 | 1,864 | 2,207 | 65 |
| **2018** | 26,071,321 | 1,448,446 | 2,188 | 3,494 | 112 |
| **2019** | 25,275,437 | 1,343,462 | 2,235 | 2,979 | 103 |
| | | | **Unit 2** | | |
| **2016** | 26,982,858 | 1,503,358 | 2,341 | 2,516 | 127 |
| **2018** | 26,403,872 | 1,497,576 | 2,406 | 3,632 | 104 |

| Year | Heat Input (MMBtu/yr) | Coal Throughput (tpy) | $NO_X$ (tpy) | $SO_2$ (tpy) | $PM_{10}$ (tpy) |
|---|---|---|---|---|---|
| **2019** | 23,417,570 | 1,349,140 | 2,100 | 2,777 | 92 |
| | | **Unit 3** | | | |
| **2016** | 22,646,321 | 1,222,173 | 852 | 851 | 32 |
| **2017** | 25,715,188 | 1,432,627 | 1,122 | 1,163 | 101 |
| **2018** | 26,938,375 | 1,480,843 | 1,092 | 1,106 | 366 |
| | | **Unit 4** | | | |
| **2016** | 23,845,639 | 1,326,676 | 912 | 1,038 | 18 |
| **2017** | 21,565,128 | 1,196,220 | 878 | 915 | 14 |
| **2018** | 23,281,713 | 1,229,277 | 996 | 1,167 | 60 |

## 2.3 ADEQ Screening Methodology

ADEQ considered unit processes that underwent evaluation in regional haze round 1, BACT analysis post 2014 or other SIP actions to achieve compliance with the NAAQS post 2014 as effectively controlled for the purposes of this regional haze analysis.

Unit Processes that emit $PM_{10}$, $SO_2$ 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 source was subject to four factor review. The Q/d value for SGS was determined to have a Q/d of over 300 for Mount Baldy Wilderness, making the facility subject to four-factor review.

ADEQ's default methodology for conducting a four-factor analysis was to limit the number of processes considered to only those processes that make up the top 80% of emissions at the source. Prior to providing TEP with the result of the screening analysis, discussions with TEP revealed that their reported PM emissions for the cooling towers assumed PM=$PM_{10}$. TEP provided a speciation analysis on particulate matter from cooling towers to demonstrate that $PM_{10}$ was significantly lower than PM and should not be included in the four factor analysis. ADEQ reviewed this analysis and agreed with results of TEP's speciation report. Table 5 shows the top 80% of emissions at SGS after the cooling tower adjustment.

**Table 5 Top 80% of emissions at SGS based on 2018 emissions**

| Emission Unit | Process | Pollutant | Emissions (tpy) | Cumulative % of Emissions |
|---|---|---|---|---|
| **Unit 2 Boiler** | Coal Combustion | $SO_2$ | 3632 | 21% |
| **Unit 1 Boiler** | Coal Combustion | $SO_2$ | 3494 | 40% |
| **Unit 2 Boiler** | Coal Combustion | $NO_X$ | 2406 | 54% |
| **Unit 1 Boiler** | Coal Combustion | $NO_X$ | 2188 | 66% |

| Emission Unit | Process | Pollutant | Emissions (tpy) | Cumulative % of Emissions |
|---|---|---|---|---|
| **Unit 4 Boiler** | Coal Combustion | $SO_2$ | 1167 | 73% |
| **Unit 3 Boiler** | Coal Combustion | $SO_2$ | 1106 | 79% |
| **Unit 3 Boiler** | Coal Combustion | $NO_X$ | 1092 | 85% |

After identifying the top 80% of emissions at SGS, ADEQ considered the unit process emissions that were not included and identified potential emissions that should be added to the four factor analysis. The most significant exclusion was 996 tons per year of $NO_X$ from coal combustion at the Unit 4 boiler, which if added to the screening analysis would represent the top 91% of emissions at SGS. Additionally, based on the magnitude of emissions, ADEQ determined that $PM_{10}$ emissions from coal combustion at all four boilers should also be included in the four factor analysis. This addition resulted in 95% of emissions at SGS being included in the four factor analysis. Table 6 shows the final screening results. All unit process emissions that were not from coal combustion at the boilers were excluded from the four factor analysis.

**Table 6 Processes included in SGS 4FA based on 2018 emissions**

| Emission Unit | Process | Pollutant | Emissions (tpy) |
|---|---|---|---|
| **Unit 2 Boiler** | Coal Combustion | $SO_2$ | 3,632 |
| **Unit 1 Boiler** | Coal Combustion | $SO_2$ | 3,494 |
| **Unit 2 Boiler** | Coal Combustion | $NO_X$ | 2,406 |
| **Unit 1 Boiler** | Coal Combustion | $NO_X$ | 2,188 |
| **Unit 4 Boiler** | Coal Combustion | $SO_2$ | 1,167 |
| **Unit 3 Boiler** | Coal Combustion | $SO_2$ | 1,106 |
| **Unit 3 Boiler** | Coal Combustion | $NO_X$ | 1,092 |
| **Unit 4 Boiler** | Coal Combustion | $NO_X$ | 996 |
| **Unit 3 Boiler** | Coal Combustion | $PM_{10}$ | 366 |
| **Unit 1 Boiler** | Coal Combustion | $PM_{10}$ | 112 |
| **Unit 2 Boiler** | Coal Combustion | $PM_{10}$ | 104 |
| **Unit 4 Boiler** | Coal Combustion | $PM_{10}$ | 60 |

## 2.4 Proposed Control Methodology

### 2.4.1 Baseline Control Scenario (Projected 2028 Emissions Profile)

To calculate the 2028 projected emissions profile, ADEQ relied on the emissions inventory data that was submitted to the Clean Air Markets Division (CAMD) which is summarized in Table 4 above. The 2028 emissions projections for Unit 1 and Unit 2 used emissions and throughput data for 2016, 2018 and 2019. ADEQ determined that 2017 was not a representative year for Unit 1 since it was not operating for several months of the year. The 2028 emissions profile for Unit 3 and Unit 4 were based on the emissions and throughput data from 2016 through 2018. The projected air pollutants include $PM_{10}$, $SO_2$, and $NO_X$.

ADEQ calculated a scaling factor for each emission unit by dividing the annual emissions by the heat input for $SO_2$ and $NO_X$ and dividing the annual emissions by the throughput of coal combusted for $PM_{10}$. Next, ADEQ calculated the average throughput and scaling factor for each unit and pollutant, and then multiplied these values to determine the 2028 emissions projections. Table 7 below summarizes the average scaling factors and process throughputs, and the resulting projected 2028 emissions profile.

**Table 7: TEP Springerville 2028 Projections**

| | Average Scaling factor | | | Average Throughput | | | 2028 Emission Projections (tpy) | | |
|---|---|---|---|---|---|---|---|---|---|
| | $PM_{10}$ (ton/ton coal) | $NO_X$ (ton/ MMBtu) | $SO_2$ (ton/ MMBtu) | $PM_{10}$ (ton coal/yr) | $NO_X$ (MMBtu/yr) | $SO_2$ (MMBtu/yr) | $PM_{10}$ | $NO_X$ | $SO_2$ |
| **Unit 1 Boiler** | 6.92E-05 | 8.70E-05 | 1.19E-04 | 1,331,353 | 24,119,624 | 24,119,624 | 92 | 2,099 | 2,869 |
| **Unit 2 Boiler** | 7.40E-05 | 8.92E-05 | 1.16E-04 | 1,450,025 | 25,601,433 | 25,601,433 | 107 | 2,283 | 2,982 |
| **Unit 3 Boiler** | 1.15E-04 | 4.06E-05 | 4.13E-05 | 1,378,548 | 25,099,962 | 25,099,962 | 158 | 1,019 | 1,036 |
| **Unit 4 Boiler** | 2.45E-05 | 4.06E-05 | 4.54E-05 | 1,250,724 | 22,897,493 | 22,897,493 | 31 | 929 | 1,039 |

### 2.4.2 Evaluated Controls and Emission Estimates

#### 2.4.2.1 Particulate Matter Emission Controls

Particulate matter emissions from pulverized coal-fired boilers are typically comprised of fly ash and incomplete combustion material. Subbituminous coals have an ash content of less than or equal to 10%[6]. Particulates are also formed as an unwanted byproduct as a result of ammonia injection for control technologies such as a selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). The following devices can be used to control particulate matter emissions from coal-fired power plants:

- Baghouse – currently installed Units 1-4
- Wet Electrostatic Precipitator (Wet ESP)
- Dry Electrostatic Precipitator (ESP)
- Wet Scrubber
- Cyclones

[6] Bowen, B, Irwin, M. (October 2008). Coal Characteristics CCTR Basic Facts File #8. West Lafayette, IN: The Energy Center at Discovery Park Purdue University. https://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/outreach/Basics8-CoalCharacteristics-Oct08.pdf

### 2.4.2.2 $NO_X$ Emission Controls:

Coal combustion results in the formation of both fuel and thermal $NO_X$. The production of $NO_X$ depends heavily on the nitrogen content of the fuel and the combustion process of the boiler. TEP combusts subbituminous coal in all four units which has a typical nitrogen content of 0.5 to 2 percent by weight and can result in up to 80% of the total $NO_X$ emissions[7] from these types of facilities.

Emission reductions for coal-fired boilers can be accomplished by two general methodologies: combustion controls and add-on pollution control devices. Combustion controls include technologies such as low-$NO_X$ burners, burners out of service (BOOS) and over fire air (OFA). These techniques reduce the combustion temperature and oxygen concentration which prevent the formation of both thermal and fuel $NO_X$ generated during the combustion process.

**Combustion Control Options:**

- Low-$NO_X$ burners, OFA or other combustion controls – currently installed on all four units

**Post-Combustion Control Options:**

- Selective catalytic reduction (SCR) – installed on Unit 3 and 4
- Selective non-catalytic reduction (SNCR)

### 2.4.2.3 $SO_2$ Emissions:

Sulfur oxides are formed during the combustion process of sulfur containing coal. Subbituminous coals, which contain less than 2% sulfur by weight[8] are combusted in all four units. Similarly to $NO_X$ emissions controls, coal fired electric steam generating units can reduce $SO_2$ emissions using post-combustion control technologies.

**Post combustion control technologies include:**

- Spray Dry Absorber (SDA) – Installed on all four units
- Dry Sorbent Injection (DSI)
- Circulating Dry Scrubber (CDS)
- Wet Flue Gas Desulfurization (FGD)

[7] Environmental Protection Agency. September 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 1: Bituminous and Subbituminous Coal Combustion. https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[8] https://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/outreach/Basics8-CoalCharacteristics-Oct08.pdf

## 2.5 Four Factor Analysis Review for $PM_{10}$ Emissions

### 2.5.1 Technical Feasibility

Particulate matter controls discussed above were evaluated for technical feasibility. A summary of the control technologies and technical feasibility of the devices can be found in Table 8 below. While wet scrubbers and cyclones also represent technically feasible control options for $PM_{10}$ emissions reduction, their control efficiencies range from 95-99% and 90-95% respectively.[9] As such, these control technologies are less effective than the currently installed baghouses and will not be considered further in this evaluation.

**Table 8 Evaluated $PM_{10}$ Controls**

| Emission Unit | Control Option | Technically Feasible (Y/N) | Additional Control Effectiveness (%) |
|---|---|---|---|
| Unit 1-4 | Baghouse | Y | 0% |
| Unit 1-4 | Wet ESP | Y | 0% |
| Unit 1-4 | ESP | Y | 0% |

**Baghouses:**

Baghouses control particulate matter emissions by utilizing fabric filtration and have a control efficiency up to 99.9%[10]. Units 1-4 are each equipped with baghouses to control particulate matter emissions. Therefore, baghouses are not considered further in this analysis.

**ESP and West ESP:**

Electrostatic precipitators are typically separated into two groups: dry ESPs and wet ESPs. The primary difference between the two is the method used to remove particulates from the electrodes. Wet ESPs utilize water sprays to remove particulates from the electrodes and collect the slurry material in a sump while particulate matter from dry ESPs is removed using mechanical methods, such as rapping or vibrating and collected in a hopper below the electrode. ESPs use an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. The collection efficiency of an ESP depends on the resistance of the particles in the flue gas. ESPs have typical collection efficiencies greater than 99% for fine (less than 0.1 micrometer) and coarse particles (greater than 10 micrometers)[10]. Because ESP collection efficiency is comparable to or less than that of the current baghouses installed on the units, ADEQ determined replacing

[9] Environmental Protection Agency. September 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 1: Bituminous and Subbituminous Coal Combustion. https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[10] ibid

the control device with an ESP, while technically feasible, should not be considered further.

**ADEQ Determination:**

ADEQ has determined that the baghouses currently installed on all four units adequately control particulate matter emissions from the boilers and therefore, no additional controls are necessary.

## 2.6 Four Factor Analysis Review for $NO_X$ Emissions

### 2.6.1 Technical Feasibility

A summary of the technical feasibility of the pollution control devices for $NO_x$ can be found in Table 9 below.

**Table 9 Evaluated $NO_X$ Controls**

| Control Option | Technically Feasible (Y/N) | Additional Control Effectiveness (%) | Emission Factor (lb/MMBtu) | Heat Input Rate (MMBtu/hr) | $NO_X$ Emission Rate (lb/hr) | $NO_X$ Emissions (tpy) |
|---|---|---|---|---|---|---|
| **Unit 1[1]** | | | | | | |
| LNB and OFA | Y | 0% | 0.17 | 2753 | 479 | 2,099 |
| SNCR | Y | 14% | 0.15 | 2753 | 413 | 1,809 |
| SCR | Y | 66% | 0.06 | 2753 | 165 | 724 |
| **Unit 2[2]** | | | | | | |
| LNB and OFA | Y | 0% | 0.18 | 2923 | 521 | 2,283 |
| SNCR | Y | 16% | 0.15 | 2923 | 438 | 1,920 |
| SCR | Y | 66% | 0.06 | 2923 | 175 | 768 |
| **Unit 3** | | | | | | |
| LNB, OFA and SCR[3] | Y | 0% | 0.081 | 2865 | 233 | 1,019 |
| **Unit 4** | | | | | | |
| LNB, OFA and SCR[3] | Y | 0% | 0.081 | 2,614 | 212 | 929 |

[1] Capacity factor Unit 1: 65%

[2] Capacity factor Unit 2: 69%

[3] The combination of combustion controls (LNB+SOFA) and SCR is the existing configuration of Units 3 and 4 at SGS. Since this combination represents the most effective control technologies available for $NO_x$ for coal fired EGUs, no further analysis for other control technologies is needed.

**Selective Non-Catalytic Reduction (SNCR):**

SNCR is a selective non-catalytic processes that uses an ammonia type reagent, such as urea or ammonia to reduce $NO_x$ to water and elemental nitrogen. The removal efficiency of $NO_X$ utilizing SNCR technologies for coal fire boilers ranges from 20-83%. For boilers above 400 MW most SNCR removal efficiencies are between 20 and 30% with a maximum of ~55%[11]. Another potential reaction of concern is the reaction of ammonia with sulfur trioxide. The resulting ammonia sulfates can deposit on equipment surfaces and fly ash requiring increased acid washing to preserve equipment and fly ash treatment. These additional considerations result in increased chemical consumption for treatment, and waste water generation.

**Selective Catalytic Reduction (SCR):**

The removal mechanism for SCR is similar to SNCR with the addition of a metal based catalyst with activated sites to increase removal rate. In addition to the faster reaction rate, $NO_x$ removal with SCR requires a lower operating temperature however, the temperature range is catalyst dependent. The removal of $NO_x$ can in theory be as high as over 99% but is dependent on the inlet concentration. In practice outlet $NO_x$ emissions are rarely below 0.04 lb/MMBTU[12].

Unit 1 and Unit 2

Units 1 and 2 currently operate low $NO_x$ burners with OFA to control $NO_X$ emissions. Additional potential controls include SCR and SNCR. SNCR and SCR offer respective 14-16% and 66% emission reductions over LNB with OFA controls currently installed on Units 1 and 2. The outlet emissions for SNCR are expected to be 0.15 lb/MMBTU. This is consistent with 20% efficiency for units starting with 0.2 lb/MMBTU $NO_x$ emissions that has been observed for utility boilers[13]. The expected SCR emissions are consistent with the EPA's RACT/BACT/LAER Clearinghouse (RBLC) emissions. Both of these controls are technically feasible.

Unit 3 and Unit 4

Retrofitting Unit 3 and Unit 4 with SNCR was not considered as a potential $NO_X$ emissions control because the removal efficiency of the control technology is estimated to be between 25-50%[14][13] for coal fired EGUs with nameplate capacities between 400 and 500 MWe. The current controls (LNB, OFA with SCR) represent the most effective $NO_x$ control technologies for coal fired EGUs and are estimated to achieve 85-95%[15] removal efficiency. In addition, ADEQ evaluated the current controls on these units with the RBLC and determined the current controls installed on Unit 3 and Unit 4 constitute best available control technology (BACT) for coal-fired EGUs.

[11] EPA SNCR Cost Manual – Revised April, 2019
[12] EPA SCR Cost Manual – Revised June, 2019
[13] EPA SNCR Cost Manual – Revised April, 2019
[14] See Figure 1.1a in EPA SNCR Cost Manual – Revised April, 2019.
[15] See Table 1.1-2 AP-42 Section 1.1 https://www3.epa.gov/ttncatc1/dir1/cs4-2ch2.pdf

### 2.6.2 Cost of Compliance

The cost of both the SCR and the SNCR control technologies were calculated using the EPA cost calculation spreadsheets[16]. The estimated life for SCR and SNCR were set at 30 and 20 years respectively to match current EPA guidance for these control technologies on utility boilers[17]. TEP's analysis used 20 years based on previous Regional Haze guidance, however, EPA has since reviewed multiple utility boilers and determined 30 years was the appropriate estimated life to use for utility boilers equipped with SCR. ADEQ selected an interest rate of 4.75%.

**Table 10 $NO_x$ Control Option Cost Effectiveness**

| Control option | Capital cost | Annualized Capital Cost | Annual O&M Cost | Total annual cost ($/yr) | Emission reduction (tpy) | Average Cost-effectiveness ($/ton) |
|---|---|---|---|---|---|---|
| **Unit 1** | | | | | | |
| SNCR | $11,422,587 | $897,815 | $1,361,453 | $2,259,269 | 290 | $7,791 |
| SCR | $169,483,516 | $10,711,358 | $1,849,205 | $12,560,563 | 1,375 | $9,133 |
| **Unit 2** | | | | | | |
| SNCR | $11,541,710 | $907,178 | $1,467,335 | $2,374,514 | 363 | $6,539 |
| SCR | $169,907,018 | $10,738,124 | $1,900,270 | 12,638,394 | 1,515 | $8,341 |

### 2.6.3 Visibility Impact

TEP provided a visibility modeling analysis to determine the potential visibility improvements at Class I areas resulting from a hypothetical emission control. TEP modeled a hypothetical $NO_x$ emission reduction of 2,118 tpy, which is approximately equivalent to 0.08 lb/MMBtu for both units when a control measure is implemented. This emission reduction results in a cumulative visibility improvement of 0.028 $Mm^{-1}$ and an average visibility improvement of 0.0005 $Mm^{-1}$ across 65 Class I areas on the 20% anthropogenically most impaired days (MIDs). The highest visibility improvement at a single Class I area on the MIDs, 0.00414 $Mm^{-1}$, was realized at the Salt Creek Wilderness. The visibility improvement at Mount Baldy Wilderness Area, the nearest Class I area to SGS, was 0.00227 $Mm^{-1}$ on the MIDs. For seven Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors within 300-km of the SGS, the average visibility improvement is 0.00078 $Mm^{-1}$ on the MIDs. ADEQ further reviewed the aerosol light extinction (haze budgets) data for these monitors on the MIDs over 2014-2018[18]. ADEQ estimated that the visibility improvements resulted from the hypothetical $NO_x$ emission

[16] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution Accessed: April 15, 2020
[17] EPA SCR Cost manual updated June, 2019
[18] http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

reduction account for less than 0.02% of the aerosol light extinction for any Class I areas (see Table 11).

**Table 11 Visibility Improvements from $NO_x$ Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018**

| IMPROVE Site | Distance to SGS (km) | 5-Year Average Aerosol Light Extinction[1] on MIDs over 2014-2018 ($Mm^{-1}$) | Modeled Visibility Improvement on MIDs ($Mm^{-1}$) | Percentage of Visibility Improvement to Aerosol Light Extinction (%) |
|---|---|---|---|---|
| **Mount Baldy** | 38 | 12.06 | 0.00227 | 0.0188 |
| **Petrified Forest National Park** | 101 | 13.82 | 0.00071 | 0.0051 |
| **Gila Wilderness** | 149 | 12.50 | 0.0003 | 0.0024 |
| **Bosque del Apache Wilderness** | 218 | 19.00 | 0.00234 | 0.0123 |
| **Chiricahua National Monument** | 257 | 15.86 | -0.00003[2] | -0.0002[2] |
| **Saguaro National Park** | 279 | 19.78 | 0.00048 | 0.0024 |
| **San Pedro Parks Wilderness** | 282 | 11.48 | -0.00062[2] | -0.0054[2] |
| **Salt Creek Wilderness[3]** | 449 | 36.40 | 0.00414 | 0.0114 |

[1]Aerosol light extinction includes contributions from seven species (ammonium nitrate, ammonium sulfate, coarse mass, elemental carbon, organic mass, sea salt, and fine soil).
[2]The modeled results indicate that the hypothetical $NO_x$ control slightly degrades the visibility at the two Class I areas.
[3]Although Salt Creek Wilderness is beyond 300 km from SGS, it has the highest visibility improvement in term of light extinction among 65 Class I areas modeled. The visibility improvements are less than 0.002 $Mm^{-1}$ for any other Class I areas that are beyond 300 km from SGS.

By examining a variety of metrics for visibility improvements (cumulative and average for all Class I areas, maximum at a single Class I area), ADEQ concludes that the predicted visibility improvements resulted from the emission reduction of 2,118 tpy are small.

### 2.6.4 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. A state also 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 make a determination, ADEQ considers the balance between the cost of compliance and the visibility benefits.

ADEQ has reviewed Best Available Retrofit Technology (BART) and Reasonable Progress (RP) determinations during the first regional haze second planning period. In particular, ADEQ examined how EPA accepted or rejected SCR. EPA heavily weighed two factors for their determinations: cost-effectiveness (average and incremental) in conjunction with visibility improvements in Class I areas (maximum visibility improvement at a single Class Area and total visibility improvements for all Class I Areas). While EPA did not explicitly state whether they used cost/visibility thresholds or not for their determinations, it appears that EPA would accept SCR if the cost-effectiveness was less than 5,000 $/ton and the control achieved a visibility improvement of 0.5 deciviews (dv) or above. A visibility improvement of 0.5 dv is in line with previous EPA regional haze BART determination guidelines. EPA rejected SCR with a cost-effectiveness of greater than 5,000 $/ton regardless of whether a visibility benefit was significant or not.

Considering the EPA's decisions during the first implementation period and adjusting the costs with an inflation rate, ADEQ is using an average cost-effectiveness of 6,500 $/ton as a reasonable threshold to assess whether a control option is cost excessive or not. Any controls having an average cost-effectiveness of 6,500 $/ton are cost excessive unless there are compelling evidence that the controls would result in a significant visibility improvement at Class I areas. Additionally, ADEQ determines that 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. Controls with an average cost-effectiveness between 4,000 $/ton and 6,500 $/ton are further considered based on additional cost metrics, the remaining three statutory factors, and visibility modeling, if appropriate.

#### 2.6.4.1 SNCR

The SNCR-based control options have an average cost effectiveness of 7,791 $/ton and 6,539 $/ton for Unit 1 and Unit 2, respectively, which are higher than the threshold of 6,500 $/ton ADEQ has established. The SNCR option results in a combined emission reduction of 653 tpy, significantly lower than the modeled emission reduction of 2,118 tpy. Since the modeled visibility improvements are small, it is expected that the visibility improvements from SNCR are marginal. By weighting the factors of cost of compliance and the visibility benefits, ADEQ rejects SNCR as the control to make reasonable progress.

#### 2.6.4.2 SCR

The SCR-based control options have an average cost effectiveness of 9,133 $/ton and 8,341 $/ton for Unit 1 and Unit 2, respectively, which are higher than the threshold of 6,500 $/ton ADEQ has established. It should be addressed that the average 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 1 and Unit 2 would be much shorter than 30 years. As laid out in its 2020 Integrated Resource Plan (IRP), TEP is planning to retire Unit 1 in 2027 and Unit 2 in 2032. The average cost-effectiveness would be higher if using a shorter remaining useful life 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.

The SCR option results in a combined emission reduction of 2,890 tpy, higher than the modeled emission reduction of 2,118 tpy. However, considering the magnitude of modeled emission reductions and corresponding the visibility improvement, ADEQ determines that SCR is unlikely to achieve a significant visibility improvement at Class I areas. By weighting the factors of cost of compliance and the visibility benefits, ADEQ also rejects SCR as the control to make reasonable progress.

## 2.7 Four Factor Analysis Review for $SO_2$ Emissions

### 2.7.1 Technical Feasibility

A summary of the technical feasibility of the pollution control devices for $SO_2$ can be found in Table 12 below.

**Table 12 Evaluated $SO_2$ Controls**

| Control Option | Technically Feasible (Y/N) | Additional Control Effectiveness (%) | Emission Factor (lb/MMBtu) | Heat Rate (MMBtu/hr) | $SO_2$ Emission Rate (lb/hr) | $SO_2$ Emission Rate (tpy) |
|---|---|---|---|---|---|---|
| **Unit 1**[1] | | | | | | |
| Current SDA | N/A | 0% | 0.24 | 2,753 | 655 | 2869 |
| Upgraded SDA | Y | 37% | 0.15 | 2,753 | 413 | 1809 |
| DSI | Y | 24% | 0.18 | 2,753 | 496 | 2171 |
| CDS | Y | 71% | 0.07 | 2,753 | 193 | 844 |
| Wet FGD | Y | 87% | 0.03 | 2,753 | 83 | 362 |
| **Unit 2**[2] | | | | | | |
| Current SDA | N/A | 0% | 0.23 | 2,923 | 681 | 2982 |
| Upgraded SDA | Y | 36% | 0.15 | 2,923 | 438 | 1920 |
| DSI | Y | 23% | 0.18 | 2,923 | 526 | 2304 |
| CDS | Y | 70% | 0.07 | 2,923 | 205 | 896 |
| Wet FGD | Y | 87% | 0.03 | 2,923 | 88 | 384 |
| **Unit 3**[3] | | | | | | |
| Low sulfur coal and SDA | N/A | 0% | 0.083 | 2,865 | 237 | 1,036 |
| **Unit 4**[3] | | | | | | |
| Low sulfur coal and SDA | N/A | 0% | 0.091 | 2,614 | 237 | 1,039 |

[1] Capacity factor Unit 1: 65%
[2] Capacity factor Unit 2: 69%
[3] As will be discussed in Section 2.7.1.1, ADEQ determines that the additional controls for Unit 3 and Unit 4 are not reasonable for this implementation period and no further analysis is needed.

#### 2.7.1.1 Unit 3 and Unit 4

Per Guidance on Regional Haze State Implementation Plans for the Second Implementation Period[19], a state may select to not perform further analysis for a particular unit that already has an effective emission control technology in place. Specifically, the Guidance states:

*"For the purpose of $SO_2$ control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative $SO_2$ emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of $SO_2$ is necessary to make reasonable progress."*

Units 3 and 4 are equipped with SDA systems, one of the flue gas desulfurization technologies. Both units are subject to the 2012 Mercury Air Toxics Standards (MATS) rule. The rule promulgated a single acid gas Hazardous Air Pollutant (HAP) emissions standard for all coal-fired EGUs using hydrochloric acid (HCl) as a surrogate for all acid gas HAP, as well as an alternative emissions standard for sulfur dioxide ($SO_2$) as a surrogate for the acid gas HAP that may be used if a coal-fired EGU is operating some form of flue gas desulfurization (FGD) system and an $SO_2$ continuous emissions monitoring system (CEMS). In the permit issued to TEP, all four units must meet the following emission limits as specified in Table 2 to 40 CFR part 63, subpart UUUUU:

- Total HCl emissions of 0.002 lb/MMBtu or 0.02 lb/MWh; or
- $SO_2$ emissions in excess of 0.2 lb/MMBtu or 1.5 lb/MWh.

ADEQ reviewed the most recent 5 years (2016-2020) of the $SO_2$ emissions data for SGS. The $SO_2$ emission rates for Unit 3 and Unit 4 range from 0.069 to 0.090 lb/MMBtu and from 0.076 to 0.010 lb/MMBtu on an annual basis, respectively. This clearly demonstrates that Unit 3 and Unit 4 have continuously complied with the applicable $SO_2$ emission standard of 0.20 lb/MMBtu.

Based on the above discussions, ADEQ determines that the current $SO_2$ emission control systems are efficient and additional controls on Unit 3 and Unit 4 are not reasonable for this implementation period.

#### 2.7.1.2 Unit 1 and Unit 2

Although both Unit 1 and Unit 2 have SDA systems installed and are also subject to the MATS rule, they are not able to continuously comply with the alternative $SO_2$ emission standard of 0.20 lb/MMBtu. During 2016-2020, the $SO_2$ emission rates for Unit 1 and Unit

[19] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_haze_guidance_final_guidance.pdf Pg.23

2 range from 0.210 to 0.268 lb/MMbtu and from 0.186 to 0.275 lb/MMBtu on an annual basis, respectively. Therefore, ADEQ performed further analysis for the two units.

#### 2.7.1.2.1 Spray Dry Absorber (SDA)[20]:

SDA works by mixing $SO_2$ containing gases with an alkaline solution to cause a reaction that will remove the $SO_2$ from the gas stream. The alkaline solution is introduced to a large vessel via spray nozzles where it can react with the gases for sufficient time to allow the $SO_2$ to be absorbed and react with the alkaline solution. While the reaction is taking place, heat and the gas stream dry the reaction products which can then be captured via particulate capture mechanism such as a fabric filter. The desired operating temperature range is 20 to 50$^{o}$F below saturation temperature of the gas stream. The efficiency of these systems is a function of temperature, pH and gas liquid contact.

The following operational upgrades were evaluated to determine which improvements could be made to the SDA installed on Unit 1 and 2 to reduce $SO_2$ emissions:

- Lime (CaO) quality
- Improved flue gas distribution
- Increase calcium to sulfur stoichiometric ratio
- Approach to saturation temperature
- Atomizer upgrades
- Adding an absorber vessel

##### *2.7.1.2.1.1 Lime Quality*

Sargent and Lundy evaluated the current SDA system at SGS and concluded the scrubber uses high quality lime (90% CaO) and there are no technically feasible improvements to the quality that can be made.

##### *2.7.1.2.1.2 Improved Flue Gas Distribution*

S&L's analysis also indicated there was a flue gas imbalance in the four SDA vessels currently used to control emissions from Unit 1 and Unit 2. The 4$^{th}$ vessel is currently receiving approximately 25% more flue gas than the other three vessels. It is believed that the current lime supply to the unit is insufficient to control the additional $SO_2$ intake into the unit and therefore the $SO_2$ emissions from the unit are 15-20% higher than the other three vessels. The report proposes enhancements such as adding perforated plates as well as a balancing damper on the flue gas inlets to each damper to remove the imbalance. Correcting the maldistribution of the flow will allow for greater residence time and proper reactant injection for each of the vessels.

[20] EPA Air Pollution Control Fact Sheet: Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers

#### *2.7.1.2.1.3 Increased Ca:S Stoichiometric Ratio*

The Ca:S ratio is important in controlling $SO_2$ emissions from the vessels. The ratio can be changed by adjusting the recycle rate of the lime or the rate of fresh lime injection. Currently, TEP recycles approximately 20-55% solids[21]. A further increase in recycle rate is not considered technically feasible. Increasing the fresh lime rate would result in a decrease of $SO_2$ emissions and is considered a technically feasible option.

#### *2.7.1.2.1.4 Approach to Saturation Temperature*

Vessels A-C currently operate 25-30 degrees above the adiabatic saturation temperature. Vessel D, which currently receives 25% more flue gas than the others operates 50 degrees above the saturation temperature. Operating at the proper saturation temperature is critical for removing $SO_2$ as it allows for the correct residence time for $SO_2$ removal. Correcting the flue gas maldistribution is expected to correct the temperature of Vessel D such that it mimics Vessels A-C.

#### *2.7.1.2.1.5 Atomizer Upgrades*

The atomizers in all four units are considered modern, thus, no additional improvements are expected if the atomizers are replaced.

#### *2.7.1.2.1.6 Additional Absorber Vessel*

S&L also considered the addition of a new absorber vessel to increase the residence time and the Ca:S ratio of the scrubbers, however it was determined that an additional unit would not result in any further $SO_2$ reductions.

The specific upgrades being proposed by TEP are to lower the stack emissions set point in order to increase the sorbent injection rate and to balance the distribution of gas in the four current SDA vessels to maximize renewal efficiency.

The current SDA system has a control efficiency of approximately 90%. Upgrading the current SDA for Unit 1 and 2 is considered technically feasible.

### 2.7.1.2.2 Dry Sorbent Injection (DSI)[20]:

DSI injects dry sorbent into the system to react with the gas stream. The resulting dry waste after $SO_2$ removal is captured using standard PM capturing mechanisms and typically involves cooling the gas before it enters the PM control device. The operating temperature depends on where the sorbent is injected into the system, and is as high as 1000ºF if injected into the furnace and as low as 150ºF when injected into the duct. Removal efficiencies of DSI systems depends heavily on an even distribution of sorbent injection and ample residence time for the removal reaction to take place. Typical DSI

[21] S&L Report pg. 6

efficiencies range from 50 to 90% depending on the sorbent used and the size of the boiler with small and medium sized boilers having higher efficiencies. Because DSI technology is commercially available for installation on coal-fired EGUs, DSI is considered technically feasible for Unit 1 and 2.

##### 2.7.1.2.3 Circulating Dry Scrubber (CDS):

CDS works by using a fluidized bed reactor to mix the sorbent agent with the flue gas stream to promote the removal reaction. The resulting mixture containing solid reaction products and other solid material is sent to a standard PM control device where a small portion of the waste product is disposed of while the remaining mixture is recycled, mixed with fresh reagent and reintroduced to the CDS system. Larger units such as utility boilers may require more than one CDS to treat the flue gas. CDS technology has been implemented on coal-fired power plants, therefore the installation of this technology is considered technically feasible.

##### 2.7.1.2.4 Wet Flue Gas Desulfurization (Wet FGD)[20]:

In a wet FGD system the flue gas is mixed with an aqueous solution of sorbent. $SO_2$ dissolves into droplets formed during the mixing process to allow it to react with the sorbent reagent. The slurry falls and is sent to a reaction vessel to complete the removal reactions and the treated gas passes through a mist eliminator. Lime and limestone are the typical reagents, with lime providing greater efficiency but a higher cost. TEP proposes wet FGD systems are commonly installed on coal fired power plants, therefore the replacement of the current SDA with a wet FGD is considered technically feasible.

### 2.7.2 Cost of Compliance

ADEQ calculated the cost effectiveness of the four $SO_2$ control methods that were deemed technically feasible. Table 13 and table 14 show the results of the cost analysis and indicate that the upgraded SDA is the most cost effective control at 20 and 30 years useful life. The following steps were used to calculate the cost of all four control options:

1. Determine the capital cost
2. Determine the annualized capital cost based on a 20 and 30 year life and 4.75% interest (same as $NO_x$)
3. Estimate the annual O&M cost
4. Estimate the potential emissions reductions
5. Use the total annual cost (TAC) and emissions reductions to calculate the cost effectiveness in $/ton

The cost of SDA upgrades was proposed by Sargent & Lundy (S&L) on TEP's behalf. ADEQ accepted Sargent & Lundy's estimates. The capital cost is based off of vendor quotes. Equipment and materials were approximately $2 million. Material taxes was set at 0% and freight was 5%. Labor costs were based on $60 per hour which is consistent with

Bureau of Labor Statistics for employees in the electrical generation field which includes, engineers, managers and legal. The remaining capital costs are based on Sargent & Lundy's estimates of a certain percentage of labor and total direct costs. The direct operating and maintenance costs were based on the cost of waste disposal, lime reagent, and additional power and water requirements. The waste disposal cost was compared to the EPA cost manual for particulate matter where the cost of disposal was $1.50 per ton. The cost of the additional power was compared to Energy Information Administration (EIA) wholesale power prices. These costs were comparable to the estimates provided by S&L. Indirect operating costs were a percentage of the total capital investment (TCI) and were taken from the EPA cost manual.

DSI is less effective than the SDA upgrades removing about 300 less tons of $SO_2$ per year. S&L calculated the cost effectiveness of DSI in a similar fashion to SDA. The equipment cost was over $9 million and total direct costs of $12 million. ADEQ compared this to the total capital cost of DSI for a 1,300 MW boiler controlled by DSI from EIA which was ~$34/kW and would equate to over $14 million for TEP units 1 and 2 each. ADEQ calculated labor in the same manner as for the SDA upgrades. ADEQ calculated the waste disposal, lime cost, auxiliary power, insurance, property taxes and administration in the same manner as the SDA upgrades Table 13 and Table 14 show that DSI is not cost effective at 20 or 30 years of useful life.

Wet FGD capital costs were based on the EPA retrofit cost analyzer. The result is the total capital cost for Wet FGD is $250 million. The CDS capital cost was based on controls identified by the EIA using EIA form 860[22] for generators above 400 MW that were retrofit with CDS. The EPA retrofit cost calculator was used to estimate the operating costs for CDS and Wet FGD. The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD. Table 13 shows that CDS and wet FGD are not cost effective at 20 years life, with average cost-effectiveness approximately or exceeding $6,500 /ton. Table 14 shows that CDS is not cost effective at 30 years but wet FGD requires further consideration at about $5000/ton for each unit.

Incremental cost effectiveness for wet FGD ranges from approximately $7,800 /ton up to just over $11,100 /ton depending on the useful life of the equipment and the unit in question. The exact useful life of wet FGD is unknown (resulting in a range of average and incremental cost-effective values between $4,900 - $6,900 /ton and $7,800 - $11,200 /ton, respectively) and the resulting range of costs are either on the high side or outside of what ADEQ would consider cost-effective. Additionally, while wet FGD provides a larger $SO_2$ emission reduction as compared to upgrading the SDA, ADEQ finds the large capital and annualized costs associated with this technology excessive given the determination that another viable reasonable control exists to reduce $SO_2$ emissions from Units 1 & 2

[22] https://www.eia.gov/electricity/data/eia860/

(upgraded SDA). Therefore, ADEQ finds that wet FGD is not a cost-effective $SO_2$ control. Similarly, CDS also exceeds ADEQ's cost-effectiveness threshold for reasonable controls.

**Table 13 $SO_2$ Control Option Cost Effectiveness for 20 Years**

| Control option | Capital cost | Annualized capital cost | Annual O&M cost | Total annual cost ($/yr) | Emission reduction (tpy) | Cost Effectiveness($/ton) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Average | Incremental |
| **Unit 1** | | | | | | | |
| Upgraded SDA | $3,709,228 | $291,362 | $627,207 | $918,569 | 1,060 | $867 | n/a |
| DSI | $19,287,201 | $1,515,019 | $6,700,270 | $8,215,289 | 699 | $11,753 | n/a[1] |
| CDS[2] | $205,962,996 | $16,178,490 | $695,000 | $16,873,490 | 2,025 | $8,332 | $16,534 |
| Wet FGD[2] | $250,000,000 | $19,637,617 | -$2,544,000 | $17,093,617 | 2,508 | $6,817 | $11,171 |
| **Unit 2** | | | | | | | |
| Upgraded SDA | $3,709,228 | $291,362 | $654,667 | $946,029 | 1,062 | $891 | n/a |
| DSI | $19,287,201 | $1,515,019 | $7,030,712 | $8,545,731 | 678 | $12,604 | n/a[1] |
| CDS[2] | $205,962,996 | $16,178,490 | $638,000 | $16,816,490 | 2,086 | $8,063 | $15,498 |
| Wet FGD[2] | $250,000,000 | $19,637,617 | -$2,850,000 | $16,787,617 | 2,598 | $6,463 | $10,314 |

[1] DSI is less effective and more expensive than SDA and so no incremental cost effectiveness was calculated.

[2] The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD.

**Table 14 $SO_2$ Control Option Cost Effectiveness for 30 Years**

| Control option | Capital cost | Annualized capital cost | Annual O&M cost | Total annual cost ($/yr) | Emission reduction (tpy) | Cost Effectiveness($/ton) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Average | Incremental |
| **Unit 1** | | | | | | | |
| Upgraded SDA | $3,709,228 | $234,458 | $627,207 | $861,665 | 1,060 | $813 | n/a |
| DSI | $19,287,201 | $1,219,133 | $6,700,270 | $7,919,403 | 699 | $11,330 | n/a[1] |
| CDS[2] | $205,962,996 | 13,018,808 | $695,000 | $13,713,808 | 2,025 | $6,772 | $13,318 |
| Wet FGD[2] | $250,000,000 | $15,802,363 | -$2,544,000 | 13,258,363 | 2,508 | $5,287 | $8,561 |
| **Unit 2** | | | | | | | |
| Upgraded SDA | $3,709,228 | $234,458 | $654,667 | $889,125 | 1,062 | $837 | n/a |
| DSI | $19,287,201 | $1,219,133 | $7,030,712 | $8,249,845 | 678 | $12,168 | n/a[1] |
| CDS[2] | $205,962,996 | $13,018,808 | $638,000 | $13,656,808 | 2,086 | $6,548 | $12,468 |
| Wet FGD[2] | $250,000,000 | $15,802,363 | -$2,850,000 | $12,952,363 | 2,598 | $4,986 | $7,854 |

[1] DSI is less effective and more expensive than SDA and so no incremental cost effectiveness was calculated.
[2] The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD.

### 2.7.3 Time Necessary for Compliance

The only cost effective control option at 20 and 30 years for $SO_2$ is upgrading the current SDA system. ADEQ proposes the compliance deadline should be three years after EPA approval of the control into the Arizona State Implementation Plan.

### 2.7.4 Energy and Non-Air Quality Impacts

Upgrading the SDA will lead to additional solid waste from increased lime consumption, additional water consumption and increased energy consumption from handling a higher amount of lime.

### 2.7.5 Remaining Useful Life of Source

The remaining useful life for Units 1 and 2 was estimated at a maximum of 30 years based on the maximum useful life (30 years) used in the four factor analysis for installing an SCR.

### 2.7.6 Visibility Impact

TEP provided a visibility modeling analysis to determine the potential visibility improvements at Class I areas resulting from a hypothetical emission control. TEP modeled a hypothetical $SO_2$ emission reduction of 3,236 tpy, which is approximately equivalent to 0.08 lb/MMBtu for both units when a control measure is implemented. This emission reduction results in a cumulative visibility improvement of 0.625 $Mm^{-1}$ and an average visibility improvement of 0.00962 $Mm^{-1}$ across 65 Class I areas on the MIDs. The highest visibility improvement at a single Class I area on the MIDs, 0.05598 $Mm^{-1}$, was realized at San Pedro Parks Wilderness. The visibility improvement at Mt. Mount Baldy Wilderness Area, the nearest Class I area to SGS, was 0.0357 $Mm^{-1}$ on the MIDs. For seven IMPROVE monitors within 300-km of the SGS, the average visibility improvement is 0.02833 $Mm^{-1}$. ADEQ further reviewed the aerosol light extinction (haze budgets) data for these monitors on the MIDs over 2014-2018. ADEQ estimated that the visibility improvements resulted from the hypothetical $SO_2$ emission reduction account for less than 0.5% of the aerosol light extinction for any Class I areas (see Table 15).

**Table 15 Visibility Improvements from $SO_2$ Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018**

| IMPROVE Site | Distance to SGS (km) | 5-year Average of Aerosol Light Extinction on MIDs over 2014-2018 ($Mm^{-1}$) | Modeled Visibility Improvement on MIDs ($Mm^{-1}$) | Percentage of Visibility Improvement to Aerosol Light Extinction (%) |
|---|---|---|---|---|
| **Mount Baldy** | 38 | 12.06 | 0.0257 | 0.2131 |
| **Petrified Forest National Park** | 101 | 13.82 | 0.0304 | 0.2200 |
| **Gila Wilderness** | 149 | 12.50 | 0.04629 | 0.3703 |
| **Bosque del Apache Wilderness** | 218 | 19.00 | 0.01999 | 0.1052 |
| **Chiricahua National Monument** | 257 | 15.86 | 0.00855 | 0.0539 |
| **Saguaro National Park** | 279 | 19.78 | 0.0114 | 0.0576 |
| **San Pedro Parks Wilderness** | 282 | 11.48 | 0.05598 | 0.4876 |

While the modeled visibility improvements from the $SO_2$ emission control scenario are greater than the $NO_x$ emission control scenario (see section 2.6.3), ADEQ determines that the predicted visibility improvements resulted from the $SO_2$ emission reduction of 3,236 tpy are not large enough to necessitate ADEQ reconsider the determinations previously made based on control cost-effectiveness.

### 2.7.7 Determining Control Measures that are Necessary to Make Reasonable Progress

#### 2.7.7.1 Upgraded SDA

As shown in Table 13, the upgraded SDA control option has an average cost-effectiveness at 20 years of 867 $/ton and 891 $/ton for Unit 1 and Unit 2, respectively. Although the visibility benefits from this control option are likely to be small, it is more compelling to conclude that the control is cost effective because the average cost-effectiveness number is well within the range ADEQ considers reasonable. Therefore, it is reasonable to require TEP to upgrade the current SDA systems to further reduce the $SO_2$ emissions at Unit 1 and Unit 2 or an equivalent $SO_2$ emission reductions from Units 1 and 2 achieved through other means.

#### 2.7.7.2 CDS and Wet FGD

As shown in Table 13 and Table 14, the average cost-effective values for CDS are higher than the ADEQ's cost-effectiveness threshold of 6,500 $/ton. Additionally, the incremental cost-effective values for CDS are above 12,000 $/ton, which is cost excessive.

Incremental cost effectiveness for wet FGD ranges from approximately $7,800 /ton up to just over $11,100 /ton depending on the useful life of the equipment and the unit in question. The exact useful life of wet FGD is unknown (resulting in a range of average and incremental cost-effective values between \$4,900 - \$6,900 /ton and \$7,800 - \$11,200 /ton, respectively) and the resulting range of costs are either on the high side or outside of what ADEQ would consider cost-effective. Additionally, while wet FGD provides a larger $SO_2$ emission reduction as compared to upgrading the SDA, ADEQ finds the large capital and annualized costs associated with this technology excessive given the determination that another viable reasonable control exists to reduce $SO_2$ emissions from Units 1 & 2 (upgraded SDA). Therefore, ADEQ finds that wet FGD is not a cost-effective $SO_2$ control. Similarly, CDS also exceeds ADEQ's cost-effectiveness threshold for reasonable controls.

The CDS and wet FGD control options result in an emission reduction of 4,111 tpy and 5,106 tpy, respectively, higher than the modeled emission reduction of 3,236 tpy. However, considering the magnitude of modeled emission reductions and the corresponding visibility improvements, ADEQ determines that the two control options are unlikely to achieve a significant visibility improvement at Class I areas.

ADEQ also reviewed the source apportionment 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[23]. As shown in Table 15, the $SO_2$-attibuted ammonium sulfate extinction due to U.S. anthropogenic sources accounts for less than 10% of the aerosol light extinction on the MIDs at seven Class I areas within 300 km of SGS. Comparatively, the international anthropogenic sources accounts for up to 25% of the aerosol light extinction (data not shown). In general, the $SO_2$ anthropogenic sources from U.S. are not the major contributor to the visibility impairment at Class I areas of interest.

**Table 16 Ammonium Sulfate Extinction from U.S. Anthropogenic Sources**

| IMPROVE Site | Distance to SGS (km) | Modeled Ammonium Sulfate Extinction from US Anthropogenic Sources ($Mm^{-1}$) | Modeled Aerosol Light Extinction on MIDs ($Mm^{-1}$) | Percentage of Ammonium Sulfate Extinction from US Anthropogenic Sources to Aerosol Light Extinction (%) |
|---|---|---|---|---|
| Mount Baldy | 38 | 0.365 | 8.375 | 4.4 |
| Petrified Forest National Park | 101 | 0.602 | 10.622 | 5.7 |
| Gila Wilderness | 149 | 0.508 | 10.099 | 5.0 |
| Bosque del Apache Wilderness | 218 | 1.265 | 12.912 | 9.8 |
| Chiricahua National Monument | 257 | 0.277 | 7.069 | 3.9 |
| Saguaro National Park | 279 | 0.401 | 19.292 | 2.1 |
| San Pedro Parks Wilderness | 282 | 0.88 | 10.176 | 8.6 |

Based on the above discussions, the visibility benefits resulted from the two control options are not compelling when considering a relatively high average cost-effectiveness,

[23] https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx

an excessive incremental cost-effectiveness, and an excessive capital cost of the controls. Therefore, by weighting the factors of cost of compliance and the visibility benefits, ADEQ rejects CDS and wet FGD as the control to make reasonable progress in the second implementation period.

This determination is also consistent with the EPA's BART Guidelines, which recommend States to evaluate upgrade options for scrubbers currently achieving at least 50 percent removal efficiencies[24]. For existing $SO_2$ controls achieving removal efficiencies of less than 50 percent, the BART Guidelines require States to consider constructing a new FGD system. While these guidelines are for BART sources, ADEQ believes that the same principles are applicable to the RP sources. Since the current SDA systems at Unit 1 and Unit 2 are effective with a control efficiency more than 85%, ADEQ concludes that it is more reasonable to upgrade the SDA systems rather than replacing the systems with a CDS or wet FGD.

### 2.7.8 Emission Limits

Based on the four-factor analysis as discussed above, ADEQ determines that emission reductions equivalent to SDA upgrades at Unit 1 and Unit 2 are necessary to make reasonable progress. Therefore, ADEQ establishes the $SO_2$ emission limits for the two units in lieu of updating the current SDA systems. However, TEP is not required to upgrade the SDA systems to demonstrate compliance with the limits, and may pursue other means of meeting the limits. This is consistent with the EPA's RP determination on Phoenix Cement Company (PCC) in the first implementation period. The EPA established an annual emission limit for PCC Clarkdale Kiln 4 based on SNCR but allowed PCC to comply with the limit using other means such as a reduction of production levels[25].

The form of pounds per MMBtu on a 30-operating day rolling average is most common for EGUs equipped with a CEMs. As stated in the EPA's Guidance[26], the Regional Haze Rule also allows SIPs to contain mass-based emission limits for circumstances under which the state had determined to be reasonable. To support a more responsive and sustainable resource portfolio for power production, TEP may significantly reduce the operating hours and throughputs for Unit 1 and Unit 2 in the future. As discussed in TEP's 2020 Integrated Resource Plan (IRP)[27], Units 1 will transition to seasonal operation in 2023 and Unit 2 in 2024. TEP is planning to retire Unit 1 in 2027 and Unit 2 in 2032. TEP will be very likely to manage its operating level strategically instead of the upgrades of the SDA systems for meeting the RP requirements. Therefore, ADEQ determines that a mass-based emission limit is reasonable.

[24] 70 Fed. Reg. 39171
[25] 79 FR 52460
[26] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_regional_haze_guidance_final_guidance.pdf Pg. 44
[27] https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf

To establish emission limits for Unit 1 and Unit 2, ADEQ considers three key factors: visibility protection, equivalent to upgraded SDA, and compliance flexibility:

- Because the two emission units are identical (capacity, coal-fired method, coal source, and control systems) and have similar emission temporal profiles and stack parameters, it is expected that a unit emission rate (such as 1 ton) from the two emission units would have an identical modeled visibility impact at Class I areas. Therefore, ADEQ is proposing capped emission limits for the two units rather than establishing an individual emission limit for each unit.

- ADEQ is proposing a capped annual emission limit of 3,729 tons per year for the units. This emission limit is derived from an emission rate of 0.15 lb/MMBtu, which is consistent with upgraded SDA as a control technology, and an average annual heat input of 49,721,058 MMBtu over the baseline years (2016, 2018 and 2019). For details, see Table 17.

**Table 17 Annual Capped Emissions Limit for Unit 1 and Unit 2**

| Units | 2016 Heat Input (MMBtu) | 2018 Heat Input (MMBtu) | 2019 Heat Input (MMBtu) | Average Heat Input (MMBtu/year) | Emission Rate Factor (lb/MMBtu) | Emission Limit (tpy) |
|---|---|---|---|---|---|---|
| **Unit 1** | 21,012,116 | 26,071,321 | 25,275,437 | 24,119,624 | | |
| **Unit 2** | 26,982,858 | 26,403,872 | 23,417,570 | 25,601,433 | | |
| **Combined** | 47,994,974 | 52,475,193 | 48,693,007 | 49,721,058 | 0.15 | 3,729 |

- To ensure short-term visibility protection, ADEQ has also explored a mass-based emission limit expressed in terms of tons per day on 30-calendar-day rolling average. ADEQ reviewed the daily $SO_2$ emissions for Unit 1 and Unit 2 over the baseline years (2016, 2018 and 2019), and obtained the maximum combined 30-calendar-day rolling average of 26.8 tons per day over the two units. ADEQ then applied a control efficiency of 36% (which is consistent with the upgraded SDA) and calculated an emission limit of 17.1 tons per day on a 30-calendar-day rolling average.

In summary, ADEQ is proposing the following two capped combined emission limits for Unit 1 and Unit 2:

- 3,729 tons per year on 12-month rolling average; and

- 17.1 tons per day on a 30-calendar-day rolling average.

ADEQ believes that establishing the two capped emission limits within the two emission units can provide compliance flexibility yet still guarantee that each unit is well controlled to protect and improve the visibility in Class I areas. TEP must comply with the emission limits no later three years after the SIP approval.