State of Utah

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DAQP-064-21

July 27, 2021

Gerald Hascall
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Dear Mr. Hascall and Mr. Netz,

The DAQ has received your four-factor analysis for the Sunnyside Cogeneration Power Plant prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of each analysis outlining some outstanding issues for you to be aware of. Please provide the DAQ with amendments or reasoning for these issues by **August 31st, 2021**. If you have any questions, please contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino
Environmental Scientist

RNC:CC:GS:jf

<u>Regional Haze – Second Planning Period</u>
<u>SIP Evaluation Report:</u>

<u>Sunnyside Cogeneration Facility</u>

Utah Division of Air Quality

July 30, 2021

SIP EVALUATION REPORT

Sunnyside Cogeneration Facility

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Reginal Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the Sunnyside Cogeneration Facility.

1.1 Facility Identification

Name: Sunnyside Cogeneration Facility
Address: State Road 123, #1 Power Plant Road, Sunnyside, Utah
Owner/Operator: Sunnyside Cogeneration Associates
UTM coordinates: 552,984 m Easting, 4,377,786 m Northing, UTM Zone 12

1.2 Facility Process Summary

The Sunnyside Cogeneration Facility (Sunnyside) is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park, (91 miles), Capitol Reef National Park (95 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles). The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light [UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory Policy Act of 1997 ('PURPA"). The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATSI Rule. As a result Sunnyside is required to meet standard of 0.2 lb/MMBtu of SO2.

This standard requires continuous monitoring with a continuous emission monitor system (CEMS). The plant's CFB boiler, designed by Tampella Power, produces steam that drives a Dresser Rand turbine generator. The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. The current boiler produces emissions from one stack at Sunnyside's cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Circulating Fluidized Bed Combustion Boiler - Rated at 700 MMBtu/hr and fueled by coal, coal refuse or alternative fuels, and fueled by diesel fuel during startup, shutdown, upset condition and flame stabilization. This boiler is equipped with a limestone injection system to the fluidized bed and a baghouse. This boiler is subject to 40 CFR 60, Subpart Da and CAM.
- One diesel engine, approximately 201 HP, used to power the emergency backup fire pump, and various portable I/C engines to power air compressors, generators, welders and pumps.
- A 500 kW emergency standby diesel generator, used in the event of disruption of normal electrical power and testing/maintenance.

1.4 Facility Current Potential to Emit

The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	1,289.26
NO_x	771.2

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a “top-down” fashion similar to U.S. EPA’s guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ will make note, and provide additional information as necessary.

3.0 Source Evaluation of Baseline Emission Rates

Sunnyside has provided the following emissions for this four-factor analysis which are based on actual emission rates. The projected annual emissions from the boiler for both NOx and SO2 are determined using CEMS data while the emergency generator and emergency diesel engine are based on the manufacturer specifications and past-actual usage. These same baseline rates are provided to UDAQ for use in the on-the-books/on-the-way basis for modeling because no changes to boiler and/or emergency generator operation are expected between now and 2028.

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler	Emerg. Diesel Engines	Emergency Generator
SO2	471	0.001	0.020
NOx	431	0.020	0.310

The values for the CFB boiler are based on the facility's average annual emissions (tons/yr) for NOx and SO2 between 2016 and 2018, as recorded by the plant's CEMS. The three-year averaged values represent reasonable expected emissions for the coal-fired boiler, emergency engine, and emergency generator. The emergency generator and emergency diesel engine's emissions are calculated using manufacturer's specifications and yearly operating data, including the amount of diesel used and annual hours of operation. Using the baseline annual emissions, SO2 and NOx emissions from the boiler and emergency equipment were reviewed on a lb/MMBTU basis and a lb/HP-hr basis respectively.

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler lb/MMBtu	Emerg. Diesel Engines lb/hp-hr	Emergency Generator lb/hp-hr
SO2	0.17	8.29E-4	2.71E-3
NOx	0.15	1.66E-2	4.20E-2

When compared to Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) limits in the RACT/BACT/LAER Clearinghouse (RBLC) database, the boiler's SO2 and NOx emission levels on a lb/MMBTU basis are comparable to PSD BACT limits for CFB boilers that process refuse coal, and are significantly lower than emission limits provided in Sunnyside's Title V permit (0.42 lb SO2/MMBtu and 0.25 lb NOx/MMBtu respectively).

4.0 Source Four Factor Analysis for Emission Reductions

4.1 SO2 Emissions - CFB Boilers

4.1.1 Step 1: Identification of Available Retrofit Control Technologies

SO2 is generated during fuel combustion in a boiler, as the sulfur in the fuel, specifically the waste-coal, is oxidized by oxygen in the combustion air. The available SO2 retrofit control technologies for the Sunnyside CFB boiler are summarized below. Alternate fuels are not considered in this analysis based on the CFB boiler is not designed for burning other fuels; therefore, it exists as the base case. The retrofit controls predominantly include add-on controls that eliminate SO2 after it is formed. Sunnyside currently uses limestone injection to control SO2 emissions. This top-down control review investigates whether installation of an additional SO2 control device in series with the prior control technology is warranted.

SO2 Control Technologies:
Spray Dry Absorbers
Wet Scrubbing
Dry Scrubbing
Hydrated Ash Reinjection

Spray Dry Absorbers
Spray dry absorption involves spraying a high concentration, aqueous slurry sorbent, typically consists of lime, sodium bicarbonate, or trona, into the wet flue gas stream. The sorbent interacts with acid gases (HCl, for example) or SO2 and forms larger particles, while the evaporation of water from the slurry cools the flue gas stream. The cooling enhances precipitation of these particles from the flue gas stream, and the particles can be subsequently removed using an electrostatic precipitator or dry filter downstream. Spray dry absorbers require sufficient water to prepare the aqueous alkaline slurry. Water usage can vary greatly as injection rates of slurry and dilution water are controlled by signals from the in-stack CEMS and the stack temperature.

Wet Scrubbing
A wet scrubber is a technology that may be installed downstream of the boiler. In a typical wet scrubber, the flue gas flows upward through a reactor vessel, while an aqueous slurry of alkaline reagent flows down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to maximize dissolution of SO2 into the alkaline reagent by distributing the reagent across the scrubber vessel. The calcium (typically) in the aqueous reagent reacts with the SO2 in the flue gas to form calcium sulfite (CaSO3) and/or calcium sulfate (CaSO4), which collects in the bottom of the reactor and is subsequently removed with the scrubber sludge.

Dry Scrubbing – Dry Sorbent
Dry scrubbers utilize powdered sorbents, such as dry limestone or lime, and pneumatically inject the powder downstream of the boiler. A dry scrubber would be an add-on control technology after the limestone injection already occurring in the CFB boiler. Dry sorbent injection involves a sorbent storage tank, feeding mechanism, transfer line, blower and injection device. An expansion chamber is located downstream of injection point to increase residence time and efficiency. SO2 in the flue gas reacts directly with the powdered reagent to form waste particles which are subsequently carried in the flue gas through a particulate control device, such as a fabric filter or electrostatic precipitator, where the particles are collected from the cleaned flue gas. Dry scrubbers are usually applied when lower removal efficiencies are required, or for smaller plants. Effects on plant operation vary for the different sorbents. Some coal-fired boiler owners and operators select to use hydrated lime if possible in order to avoid potential heavy metal leaching from the collected fly ash mixed with DSI byproduct.

Dry Scrubbing - Hydrated Ash Reinjection
Hydrated ash reinjection (HAR) effectively reduces SO2 emissions by increasing the extent of reaction between SO2 and hydrating sorbents in the CFB. The CFB recycles fly ash in the system for a specified period, after which the flue gas is sent to a particulate control device where the sulfur-rich particulates are collected. Design and efficiencies for HAR systems vary greatly based on vendor and sorbent type. HAR also requires significant amounts of fly ash to maintain reaction rates that sustain desulfurization of the flue gas.

4.1.2 Step 2: Eliminate Technically Infeasible Control Technologies

Spray Dry Absorbers

Installing an additional spray dry absorber in series with the current FGD system would further reduce SO2 emissions at Sunnyside's facility. Despite the misleading name, spray dry absorbers (also known as semi-dry absorbers), require water to atomize the reactive sorbent into an aqueous solution. Sunnyside's operation as a cogeneration facility already requires a significant use of water, and the plant's current water rights are not sufficient enough to sustain the necessary water usage to operate an additional spray dry absorber. In 2018, Sunnyside Cogeneration exceeded their allotted water rights. Consequently, it had to purchase 44.5 million gallons of additional water from the city of East Carbon. The facility already uses the majority of its water rights for current operations and has to buy additional water to supply the necessary amount of water to the cooling towers. Any additional water consumption would result in the water rights being used much more rapidly and represents an undue burden on the facility to acquire the water for spray dry absorber operation. As additional water rights are not available in the quantity required for implementing water-intensive technology, installation of an additional spray dry absorber in series with Sunnyside's current limestone injection technology is considered infeasible and will not be evaluated further.

Wet Scrubbing
Similar to spray dry absorption, A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO2 from stack gas. However, wet scrubbing uses more water than spray dry systems to generate the aqueous sorbent. The alkaline slurry is sprayed into the absorber tower and reacts with SO2 in the flue gas to form insoluble CaSO3 and CaSO4 solids. A wet flue gas desulfurization (FGD) must be located downstream of the fabric filter baghouse. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge. As the concentration of the SO2 in the CFB gas is inherently low due to existing control technologies, it is not anticipated that a wet FGD system will provide a significant reduction in overall SO2 emissions. As mentioned previously, the plant's current water rights are not sufficient to operate a wet scrubber instead of limestone injection technology, or in series with the current limestone injection technology. Since any additional water consumption represents an undue burden on the facility to acquire the water for wet scrubber operation, this technology is considered infeasible and will not be evaluated further.

Dry Scrubbing
Dry scrubbing systems are mechanically simple systems and use less water than wet scrubbing and spray dry systems. Due to limited water use and simple waste disposal, dry injection systems install easily and are good candidates for retrofit applications. Therefore, dry scrubbing is considered technically feasible, and considered further.

Hydrated Ash Reinjection
Application of HAR results in higher particulate loading in the flue gas, and subsequently generates larger emissions particulate matter. Flue gas exiting the CFB at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash. To enable HAR, either additional limestone loading to the CFB would needed or significant amounts of ash to effectively scrub SO2. Therefore, large amounts of unreacted fly ash are required to implement HAR To be able to handle the additional loading. Additionally, a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas. HAR implementation would be impractical with 10% available CaO and even if adding

reagent would be feasible it would likely require the installation of an enhanced baghouse with the addition of additional particulate in the flue gas of the CFB due to the significant amount of ash reagent that would be required. Due to the questionable technical feasibility of HAR, and the generation of PM emissions, the technology is considered technically infeasible, and no longer considered.

4.1.3 Step 3: Rank Technically Feasible Control Options by Control Effectiveness

Control efficiency is undetermined at this time because the most effective method to determine optimal performance and balance of plant effects is to conduct a DSI trial on the unit in question. These trials typically range from one week to three months in duration, using temporary equipment designed for this purpose. For the purposes of evaluation the average of the range was used. Thus, Dry Scrubbing, the only remaining option, has a control efficiency of 50-98%.

4.1.4 Step 4: Evaluation of Impacts for Feasible Controls

Sunnyside's average emission rate of SO2 between 2016 and 2018 was 471 tons per year or approximately 0.17 lbs of SO2 per MMBTU with the utilization of limestone injection technology. Installing dry scrubbing technology at Sunnyside also requires the installation of an additional baghouse to remove particulates generated from dry scrubbing operation. Sunnyside's cost analysis of this technology shows that dry scrubbing provides an undue economic burden to the facility, costing approximately $10,372 per ton of SO2 removed.

The boiler currently operated was determined to achieve BACT for SO2 at the time of the boiler's New Source Review (NSR) permit. It has further reduced its emissions to meet NESHAPS, Part 63 Subpart UUUUU (MATS). When compared to the permitted emission rates for SO2 found in the RBLC database, Sunnyside's CFB boiler emits SO2 at a rate comparable to SO2 BACT limits of CFB boiler installations around the country. The Sunnyside CFB boiler is already equipped with limestone injection, which is currently installed primarily for SO2 control on the CFB technology. Sunnyside is currently injecting limestone to manage SO2 emissions as needed to meet the existing, appropriately low SO2 limits set forth by BACT, NSPS Subpart Da, and NESHAPs Part 63, Subpart UUUUU (MATS Rule).

Since Sunnyside's emission rate maintains parity with NSPS and MATS emission limitations for similar processes and no technologies are available to reduce the emission rate further, the current process of a limestone injection technology to achieve a reduction in SO2 emissions is considered BACT for the boiler. Furthermore, this emission rate is well below the established SO2 limitation from NSPS Subpart Da, which is 0.6 lb/MMBTU and remains below NESHAPS, Part 63 Subpart UUUUU (MATS) of 0.2 lb/MMBTU. No technologies are available to reduce SO2 emissions further. Therefore, the current process of using inherently low sulfur raw materials and natural scrubbing is considered BACT for the boiler.

Cost of Compliance:
The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels.

Dry Scrubber Cost Calculations

Dry Scrubber cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1.3 is used in determining the capital costs associated with the potential installation of dry scrubber technology.

Cost Effectiveness
The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Based on the results of this analysis, the cost of dry scrubbing is not cost effective.

SO2 Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emissions	SO2 Reductions	Emission Reductions	Cost Effectiveness
Dry Scrubber	$3,253,696	471 tons	74%	212	$10,372

Timing for Compliance:
Sunnyside believes that reasonable progress compliant controls are already in place. However, if UDAQ and WRAP determine that one of the SO2 control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following WRAP's reasonable progress determination).

Energy Impacts:
The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A. To operate any of these add-on control devices, overall plant efficiency would decrease due to the operation of the add-on controls. At a minimum, decreased efficiency would result in increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

Emission reducing options that involve water also require significant energy to operate the wet scrubber and associated equipment (pumps, atomizers, etc). However, water-intensive control technologies have been eliminated due to a lack of water availability.

The use of emissions reduction options involving the injection of lime for dry scrubbing and wet scrubbing also causes significant energy impacts. The production of lime is an energy-intensive process that can result in increases in NOx, particulate matter, and SO2 emissions, an effect directly counter to regional haze efforts.

This lime production emissions increase would then be coupled with the energy and emissions impacts resulting from the transportation of the lime to the facility. The production and delivery of lime to the Sunnyside facility would require significant energy and would result in emission increases of pollutants that directly contribute to visibility impairment around the country.

Non-Air Quality Environmental Impacts
Technically feasible add-on SO2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A dry scrubbing control system will require additional particulate loading in the flue gas thereby increasing the volume to be handled, which will put a burden on the existing baghouse system and result a larger baghouse control system to capture PM emissions exiting from the stack.

Remaining Useful Life:

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology (dry scrubbing control) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. However, the cost analysis presented in this report is based on 20 years to be conservative.

4.1.5 SO2 Conclusion:

The CFB boiler, equipped with limestone injection, inherently removes the vast majority of SO2 that is created from the process. The limestone injection configuration, as currently used was determined to achieve BACT and MATS emission limitations. Furthermore, Sunnyside's current SO2 control technology is commonly used to achieve BACT for CFB boilers

This analysis did not identify any technically feasible and cost-effective control options to reduce SO2 beyond the low levels currently achieved by control options already permitted for the boiler.

4.2 NOx Emissions – CFB Boilers

NOx emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NOx and "fuel" NOx when describing NOx emissions from the combustion of fuel. Thermal NOx emissions are produced through high-temperature oxidation of nitrogen found in the combustion air. Fuel NOx emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. Many variables can affect the equilibrium in the boiler, which in turn affects the creation of NOx.

A circulating fluidized bed reduces the fuel required to achieve sufficient material temperatures, over traditional FBC units, limiting thermal NOx production in the EGU's system. A CFB boiler uses staged combustion limiting the formation of NOx. This effect is combined with the benefits of combusting the fuel in stages, a method which allows for more fuel to be burned at a lower temperature rather than the higher peak flame temperature within the boiler, thereby reducing thermal NOx formation.

4.2.1 Step 1: Identification of Available Retrofit Control Technologies

NOx emissions controls can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature, which minimizes NOx formation. Post-combustion controls convert NOx in the flue gas to molecular nitrogen and water.

Combustion Controls: Circulating Fluidized Bed (CFB) (Base Case)
Post-Combustion Controls: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR)

Circulating fluidized bed (CFB) combustion is a specific type of fluidized bed combustion (FBC). In FBC combustion, coal is crushed into fine particles then suspended in a fluidized bed by upward-blowing jets of air. This results in a turbulent mixing of combustion air with the coal particles. The coal is mixed with a sorbent, specifically limestone (for SO2 emission control). The operating temperatures for FBC are in the range of 1,500°F to 1,670°F. CFB technology allows for operating at higher gas stream velocities and with finer-bed size particles. There is no defined bed surface but rather high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency. As noted, before, the lower peak combustion temperature reduces thermal NOx while the staged combustion reduces fuel

NOx. Sunnyside meets their Title V permitted NOx emission limits using the CFB technology. Therefore, the CFB technology will not be evaluated further.

An SCR system is a process whereby NOx is reduced by spraying a reagent, such as urea or ammonia over a catalyst in the presence of oxygen. On the catalyst surface, NH3 and nitric oxide (NO) or nitrogen dioxide (NO2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$

When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent. The rate of NOx removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NOx removal efficiency begins to decrease. SCR has been successfully installed and operated on many industrial boilers in the U.S. and therefore will be further evaluated.

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NOx and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NOx reductions. Like SCR, SNCR uses ammonia or a solution of urea to reduce NOx through a similar chemical reaction.

$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$

SNCR residence time can vary between 0.001 seconds and 10 seconds. However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NOx removal. There is a gain in performance for residence times greater than 0.5 seconds. The U.S. EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,600°F and 2,000°F, due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. At higher temperatures, NOx reduction rates decrease. In addition, a greater residence time is required for lower temperatures.
There are several complications that can occur when attempting to identify and successfully implement the necessary controls to obtain ideal temperature zones for NOx reduction, resulting in significant variability among the reduction efficiencies achieved with SNCR in boilers. In other words, SNCR in boilers have achieved varying and sometimes poor success, often due to the flue gas temperatures as well as varying combustion loads diverging from optimal values.

4.2.2 Step 2: Eliminate Technically Infeasible Control Technologies

Selective Catalytic Reduction:
The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum

temperature ranges from 480°F to 800°F. The effectiveness of an SCR system is dependent of a variety of factors, including the inlet NOx concentration, the exhaust temperature, and ammonia injection rate, the type of catalysts poisons, such as particulate matter and SO2. In practice, SCR systems can operate at efficiencies in the range of 70% to 90%. While SCR has been used for NOx control in pulverized coal applications, the nature of CFB makes it very impractical. Considering the high particulate loading rate and calcium oxide (CaO) concentration of the flue gas due to limestone injection in this section of the CFB boiler exhaust stream, and due to use of refuse coal fuel in the boiler with ash content as high as 60%, an SCR system installed upstream of particulate controls would experience rapid catalyst de-activation and fouling. These technical problems would make the operation of an SCR in the high-dust laden flue gas upstream of the particulate controls technically infeasible for a CFB boiler design.

Since low-temperature SCR is not technically feasible, another option would be to reheat the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use at (650-750°F). This increase in exhaust temperature would require an additional combustion device, also increasing NOx, SO2, and PM2.5 emissions.

The main drawback with SCR is the overall costs associated with running the system. SCR systems traditionally have high capital and operating costs as large volumes of catalyst required for the reduction reaction as well as replacement catalyst and ammonia reagent costs. Even with the increase in ammonia, PM2.5, and SO2 emissions, Sunnyside has considered this technology to be technically feasible for the CFB boiler and further evaluated the economic feasibility of this technology as detailed in Step 4.

Selective Non-Catalytic Reduction:
Successful implementation of SNCR poses several technical challenges - most related to maintaining NH3 injection within the optimal temperature range (approximately 1,600°F and 2,000°F).

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NOx level, and CO and O2 concentrations are important in determining the effectiveness of SNCR. In general, if NOx and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NOx level. SNCR is most effective within a specified temperature range or window (approximately 1,600°F and 2,000°F) At temperatures below the window, reaction kinetics are extremely slow, such that little or no NOx reduction occurs. As the temperature within the window increases, the NOx removal efficiency increases because reaction rates increase with temperature. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal. NOx generation is minimized between 1,600°F and 2,000°F because the reaction rate plateaus in this range.

Sunnyside's temperatures in the combustor are approximately 1,620 °F and cyclone outlet at 1,670 °F. Plants of similar design have installed lances to inject ammonia at the exit of the cyclone. Within 100 ft of the potential lance injection location, would be the equivalent to 0.2 seconds of residence time, the temperature drops 600 °F; therefore, falling out of the SCNR temperature window. As a result, it is believed that the control efficiency on the Sunnyside would be extremely low to the point where the controls would not be effective.

Additionally, at lower temperatures the reaction rate is slowed down, causing ammonia slip, which would result in the formation of ammonia salts, which themselves are condensable PM 2.5, a visibility impairing pollutant.

Despite the technical and adverse environmental impacts detailed above, the installation of SNCR is considered technically feasible for Sunnyside Cogeneration's boiler and will be considered further.

4.2.3 Step 3: Rank Technically Feasible Control Options by Control Effectiveness

Ranking of NOx Control Technologies by Effectiveness

Control Technique	Control Efficiency
SCR:	70-90
SNCR:	Varies Significantly [a]

[a] Control efficiency for SNCR, per the U.S. EPA Control Cost Manual Chapter 1 Figures 1.3 and 1.4 document SNCR effects from temperature and residence time.

4.2.4 Step 4: Evaluation of Impacts for Feasible Controls

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the: cost of compliance, energy impacts, non-air quality impacts, and the remaining useful life of the source.

Cost of Compliance:
The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels.

SNCR cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1 is used in determining the capital costs associated with the potential installation of SNCR.

Cost Effectiveness
The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced.

NOx Cost of Compliance Based on Emissions Reduction

Control Option	**Control Cost ($/yr)**	**Baseline Emission Level (tons)**	**NOx Reduction (%)**	**Emission Reduction (tons)[a]**	**Cost Effectiveness ($/ton removed)**
SCR	$5,199,098	432	90%	388.8	$12,039
SNCR	$678,005	432	15%[b]	367	$10,542

[a] Emission reduction assumes actual operating time of Sunnyside at 334 days per year.
[b] NOx reduction is based on evaluation of Figures 1.3 and 1.4 documenting NOx reduction percent control curves based on temperature and residence time in CFB boilers of similar design to Sunnyside.

Timing for Compliance:
Sunnyside believes that reasonable progress compliant controls are already in place. However, if the UDAQ determines that one of the control methods analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the

period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

Energy Impacts and Non-Air Quality Impacts:
As with the addition of SO2 controls, the introduction of either SNCR or SCR for NOx control will result in an increase in the electricity demand and/or waste generated at the facility. Overall plant efficiency will decrease as a result of the use of this equipment, and the generation of the necessary electricity will contribute to the plant's overall emissions and environmental impact. Environmental agencies around the country have acknowledged the significance of ammonia slip and the potential increases in condensable PM2.5 that can result from the introduction of excess ammonia slip into the atmosphere.

For jurisdictions that struggle with meeting PM standards, the California Environmental Protection Agency Air Resources Board's guidance document advises all air quality districts in California to not permit higher levels of ammonia slip:

> *"Air districts should consider the impact of ammonia slip on meeting and maintaining PM10 and PM2.5 standards, particularly in regions where ammonia is the limiting factor in secondary particulate matter formation. Where a significant impact is identified, air districts could revise their respective New Source Review rules to regulate ammonia as a precursor to both PM10 and PM2.5."*

The use of SNCR or SCR for NOx control introduces the risk of excessive ammonia slip emissions, which contributes to visibility impairing compound formation of ammonia salts. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse environmental and health impacts.

Remaining Useful Life:
The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology SCR and SNCR) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

4.2.5 NOx Conclusion:

The facility currently uses CFB technology to lower NOx emissions and achieves Title V permitting NOx limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective with a control cost greater than $10,000 per ton of NOx removed. While SNCR may represent a cost-effective option for NOx emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and PM2.5 emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a NOx emission rate on a lb/MMBtu basis that is comparable to PSD BACT levels set on CFB boilers. Therefore, additional add-on controls for NOx emissions reductions are not necessary on the Sunnyside CFB boiler.

4.3 SO2 and NOx Emissions – Emergency Generator

Sunnyside cogeneration facility has an emergency generator installed in the event of a loss of power or similar event requiring the plant and facility to maintain electric power. The emergency generator is powered by a 201 HP diesel engine. The emergency diesel engine operates in accordance with the standards set forth in 40 CFR Subpart ZZZZ, the NESHAP for Reciprocating Internal Combustion Engines (RICE) Maximum Available Control Technology (MACT) and is in adherence with the provisions set forth in its UDAQ Title V Permit. The 5000 Kw Emergency generator is subject to NSPS Subpart JJJJ.

Provisions include limiting operation to emergency procedures, emergency demand response, testing and maintenance, and operations in non-emergency settings to 50 hours per year. The emergency engine also follows best combustion practices which include changing the oil and filter after every 500 hours of operation or annually, inspect the air cleaner after every 1,000 hours of operation or annually, and inspect all hoses and belts every 500 hours of operation or annually. These will apply to whichever time provision comes first, either the hours of operation or annual mark. Sunnyside will also limit the engine's time spent at idle and minimize the engine's startup time to under 30 minutes in order to achieve appropriate and safe loading of the engine.

The annual SO2 and NOx emissions for the emergency engine and generator are quite low and attribute to less than 1% of the Boiler’s emissions. Any controls implemented to reduce the current emissions from the emergency generator and engine would result in insignificant emission reductions and only increase the financial burden for Sunnyside. Any emission reductions from the emergency engine and generator would have no statistically significant effect on the Regional Haze to the applicable Class 1 areas stated in Section 3. Sunnyside already follows the standards set forth in 40 CFR Subpart ZZZZ and its UDAQ Title V permit and will continue to follow best combustion practices in order to maintain low emissions.

5.0 UDAQ Analysis

UDAQ noted several potential errors in Sunnyside’s analysis:

1. The Sunnyside four-factor analysis for SO2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber. The Sunnyside analysis failed to evaluate the use of a circulating dry scrubber which can achieve high SO2 removal efficiencies (as high as 98% control) with lower water use and waste compared to wet or dry scrubbers.

Sunnyside’s four-factor analysis did include a cost effectiveness analysis for a “dry scrubber,” by which they were referring to dry sorbent injection. The company’s analysis found that dry sorbent injection would have a cost effectiveness of $10,202/ton of SO2 removed. More specifically, the company provided a cost analysis for a dry scrubber combined with its cost estimates for a new baghouse. A review of that cost analysis shows that there were several factors that improperly inflated the costs of a dry scrubber.

2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.

The Sunnyside Cogen four-factor analysis of installing a dry scrubber included the costs of also installing a new baghouse, even though the CFB boiler already is equipped with a baghouse. The Sunnyside four factor analysis does not explain why a new baghouse would be required with dry scrubbing. The analysis does say that for hydrated ash reinjection, “a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas.” Yet, the company claimed that it did not consider hydrated ash reinjection as technically feasible for the Sunnyside CFB boiler, due to its claim that the fly ash at Sunnyside only contains 10% unreacted calcium oxide and that “even if adding reagent would be feasible it would likely require the installation of an enhanced baghouse….” However, nothing in the company’s description of dry scrubbing in the four-factor analysis indicated or justified that a new baghouse would be necessary with dry scrubbing. Yet, in a subsequent section of the four-factor analysis, Sunnyside inexplicably stated that use of dry scrubbing technology at Sunnyside “also requires the installation of an additional baghouse to remove particulates generated from dry scrubbing operation.” Other than this statement, there was no justification for a new baghouse for dry scrubbing provided.

Before one can determine whether an upgraded baghouse would be necessary for dry scrubbing, more information on the details of the existing baghouse and existing PM rates must be provided. It must be noted that the Sunnyside four-factor analysis indicates that the coal used at the CFB boiler has a very high ash content. This is not unusual for a CFB boilers which often burn waste coal. The existing baghouse thus had to be designed for a high level of ash content. There likely was some level of additional particulate loading built into the design of the existing baghouse. In addition, there is some evidence that a baghouse used in conjunction with sodium-based sorbents, rather than the more traditional lime-based sorbents, can achieve 70-90% SO2 control without any increase in particulate matter loading. This option was not evaluated.

3. Sunnyside’s analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency

The Sunnyside Cogen four-factor analysis assumed lime would be used at the reagent for the dry sorbent injection at a ratio of 3 tons of sorbent to 1 ton of SO2 emitted and assumed 74% SO2 control would be achieved. One table of the Sunnyside DSI cost list assumes a lime injection rate of 500 lb/hr, although the company’s annual operational cost analysis assumed that 1,413 tons per year of lime would be required which, assuming the claimed baseline operating hours of 8,031 hours/year, equates to 352 lb/hr.

Using the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler and assuming that use of lime could achieve Sunnyside’s planned 74% SO2 reduction indicates that the lime injection rate would need to be 0.0921 tons per hour or 184 lb/hour, which is much lower than the 352 to 500 pounds of lime per hour assumed in the Sunnyside cost analysis for dry sorbent injection. Sunnyside should correct these inconsistencies, or at least explain which value is correct.

4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power

The Sunnyside Cogen analysis assumed an auxiliary power demand of 0.67% of total electrical generation. Sunnyside used the uncontrolled SO2 emission rate for Sunnyside’s CFB boiler of 1.7 lb/MMBtu rather than the currently controlled SO2 rate claimed by Sunnyside of 0.17 lb/MMBtu in its calculations of auxiliary power demand. The dry sorbent injection system will only need to reduce SO2 emissions from the current 0.17 lb/MMBtu rate exiting the CFB boiler, and not the uncontrolled SO2 rate of the coal. In addition, in calculating the costs of auxiliary power, Sunnyside used an electricity cost of $74.68/MWhr, which it said is the “current revenue” from Sunnyside. The Sunnyside dry sorbent injection cost analysis also states that “[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler.” However, EPA’s Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity.

Sunnyside's cost for electricity usage due to dry sorbent injection at its CFB boiler was a significant part of its annual operating costs. At an estimated $232,862 for auxiliary power, Sunnyside's projected electricity cost was 59% of its total direct annual costs of dry sorbent injection. However, Sunnyside clearly overstated the costs for auxiliary power. Even at the Company's stated electricity cost of $74.68/MWhr, the total cost for electricity should not have been any more than the following:

0.028% x 58.33 MW x 8031 hours/yr x $74.68/MW-hr = $9,795 per year.

Sunnyside's claimed cost of $232,862 per year for electricity is almost 24 times higher than what the Sargent & Lundy IPM power formula calculates would be the auxiliary power needs using lime as the sorbent to achieve 74% SO_2 control. Clearly, Sunnyside's operational expenses are overstated.

5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.

The Sunnyside Cogen dry scrubbing analysis included annual costs for administrative charges, taxes and insurances that totaled 4% of the total capital investment. Utah has a tax exemption for air pollution controls in R307-120. There is no justification for including annual costs equating to 2% of the total capital investment for taxes. With respect to administrative costs, Sunnyside assumed annual costs of dry sorbent injection equating to 2% of the total capital investment per year which, based on the company's dry sorbent injection cost estimates, would equate to $168,020 per year. EPA does not assume anywhere near that high of an administrative cost for SCR in its SCR cost spreadsheet. Specifically, EPA estimates annual administrative charges for SCR based on the formula 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost. The administrative costs for operating dry sorbent injection should not be any higher than the administrative costs for operating SCR, and would likely be lower. For the dry sorbent injection system costs as presented by Sunnyside, EPA's administrative cost equation of its SCR spreadsheet would indicate the following annual administrative costs for dry sorbent injection:

0.03 x ($22,310.63 + $3,346.59) + 0.4 x ($22,310.63+$22,310.63) = $18,741 per year

This estimated $18,741 per year for administrative overhead is almost 9 times lower than the $168,020 per year administrative cost estimate provided by Sunnyside Cogen. Thus, it appears that Sunnyside greatly overstated annual administrative costs of operating dry sorbent injection at the Sunnyside CFB boiler.

6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor

The Sunnyside Cogen four-factor analysis assumed a 1.3 retrofit factor for the dry sorbent injection part of the evaluation of dry scrubbing. This same retrofit factor was also applied to the cost analysis for SCR and SNCR as well. Yet, the company did not provide any justification for application of a retrofit factor for any of these control options at the Sunnyside CFB boiler.

EPA's SCR and SNCR cost spreadsheets state that "[y]ou must document why a retrofit factor of 1.3 is appropriate for the proposed project." For SNCR systems, EPA has stated no additional retrofit factor is justified for its SNCR spreadsheet, because it already applies a retrofit factor for installation of SNCR at an existing facility compared to installation at a new source. For retrofitted SCR systems, it must be noted that EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit. Further, given that most utility boilers that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates take into account some of the difficulties like lack of space and the need to elevate the SCR.

7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short expected life when amortizing costs

The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. The current bank prime rate is 3.25%. The Federal Reserve has indicated that it expects interest rates to remain at these low levels at least through 2023. Thus, a much lower interest rate should have been used to amortize capital costs of dry sorbent injection. Sunnyside's use of a higher than realistic interest rate would overstate the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate.

Sunnyside Cogen also only assumed a 20-year life for the dry sorbent injection system. EPA assumed a 30-year life of DSI in cost effectiveness calculations for this control at several Texas power plants. Sunnyside should have evaluated a 30-year life for the dry sorbent injection system.

8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR

The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20-year life of both SCR and SNCR. While the 4.75% interest rate used in the SCR and SNCR cost analysis is much lower than the 7% interest rate used in Sunnyside's dry sorbent injection cost analysis, a 4.75% interest rate is still an unreasonably high interest rate to assume in a cost effectiveness analysis. It is unclear why a different interest rate was chosen for this analysis – at the very least one would assume the interest rates to be the same. The current prime bank rate of 3.25% should be used or the source should provide a detailed justification for using a firm-specific interest rate.

With respect to the assumed 20-year life of SCR and SNCR, EPA has stated that the life of an SCR should be 30 years. In its SCR chapter of its Control Cost Manual, EPA included several sources for its assumed 30-year life of an SCR system at a power plant. Absent an enforceable retirement date on the remaining useful life of the Sunnyside CFB plant, it is reasonable to assume a 30-year life in estimating cost effectiveness of SCR, as EPA states in its Control Cost Manual.

9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified.

In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon. EPA's SNCR and SCR cost spreadsheets assumes a significantly lower cost at $0.293 per gallon for 29.4% aqueous ammonia, citing to the USGS Minerals Commodities

Summaries. Sunnyside provided no justification or basis for assuming a cost for aqueous ammonia that is 8.5 times higher than the cost of aqueous ammonia used in EPA's SNCR cost estimation spreadsheet, other than to put a note in the spreadsheet printouts that it was "[s]ite-specific information" and that they "[u]sed average cost of ammonia supplier costs."

10 Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis

In its SCR and SNCR cost analysis, Sunnyside assumed a cost for electricity of $0.0821/kW. Yet, in its dry sorbent injection analysis, Sunnyside Cogen assumed a lower electricity cost of $0.07468/kWhr, which the Company said is the "current revenue" from Sunnyside. As previously stated, it does not appear that the electricity cost used in the dry sorbent injection cost analysis was the most appropriate to use for estimating the costs of auxiliary power, as the Sunnyside cost analysis stated that the electricity "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler." EPA's Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity. The company is not justified in assuming any higher of a cost for electricity for an SNCR or an SCR system than what it assumed in its DSI cost analysis.

6.0 Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
   a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
   a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Any other pertinent information Sunnyside feels is warranted should also be provided in order to assist UDAQ in the review process.