Appendix E: Regional Haze Four-Factor Analysis
Hawaiian Electric Company, Inc.
Kahe Generating Station
August 12, 2022 RH-SIP Submittal

Initial Four – Factor Analysis

REGIONAL HAZE FOUR-FACTOR ANALYSIS
Kahe Generating Station

Hawaiian Electric

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1. EXECUTIVE SUMMARY

This report is submitted to comply with the second implementation period of the Regional Haze Rule (RHR). In the first implementation period, the EPA excluded sources, such as the Kahe Generating Station (Kahe), which is located on the Island of Oahu, from its analysis because of the distance and downwind location of the sources in relation to the Class I areas in Hawaiʻi.

The State of Hawaiʻi has two Class I areas (National Parks) that trigger compliance with the RHR: Hawaiʻi's Mandatory Federal Class I Areas are Haleakalā National Park on Maui and Hawaiʻi Volcanoes National Park on Hawaiʻi Island. This report documents the results of a four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric[1] for the six boilers (K1, K2, K3, K4, K5, and K6) at Kahe. K1, K2, K5, and K6 are wall-fired boilers with nominal ratings of 92 megawatts (MW), 90 MW, 142 MW, and 142 MW, respectively. K3 and K4 are tangentially-fired boilers with nominal ratings of 92 MW and 93 MW, respectively. The boilers currently burn residual oil. Also, Appendix B and Appendix C contain analyses performed by AECOM Technical Services, Inc. (AECOM) of a fifth factor that includes a review of visibility impacts.

This report addresses the options that could be considered that have the potential to lower emissions and show reasonable progress toward the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period for Kahe. Other long-term emission reduction strategies, such as those included as part of Hawaiʻi's Renewable Portfolio Standards (RPS), are viable alternatives to emissions reductions from add-on controls and changes in the method of operations.

Hawaiian Electric and AECOM met with the Department of Health (DOH) on February 12, 2020 to present special circumstances applicable in Hawaiʻi that should be given consideration in the development of the Hawaiʻi Regional Haze State Implementation Plan (SIP). Significant among those circumstances is Hawaiʻi's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty (20) years before the Regional Haze 2064 target date and that this facility is a considerable distance and mostly downwind of the Class I areas. These same issues were addressed by the EPA in the Federal Implementation Plan (FIP) and the DOH in its Progress Report[2] that was approved by the EPA effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report.

Based on the four-factor analysis and the materials set forth in the appendices, Hawaiian Electric does not propose any emissions reduction measures in addition to its RPS program to meet the RHR requirements.

[1] Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawaiʻi Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawaiʻi Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

[2] 5-Year Regional Haze Progress Report for Federal Implementation Plan, Hawaiʻi State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

2.1. REGIONAL HAZE RULE BACKGROUND

In the 1977 amendments to the federal Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural visibility conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the EPA published the final RHR (40 CFR Part 51, Subpart P). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres)[3], and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51.308(d)(1)(i)(A). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51.308(d)(1)(i)(B). The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

During the first implementation period the EPA issued a FIP (77 FR 61478, October 9, 2012; see also *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii Air Division* U.S. EPA Region 9, May 14, 2012) which determined for the first planning period that nitrogen oxides (NO_X) was not contributing to regional haze significantly as to require control measures, and that the Oahu sources were not significantly contributing to regional haze. Additionally, as part of the EPA's decision with respect to BART controls, the EPA took into account that controls would result in "unduly increasing electricity rates in Hawai'i." (see 77 FR 31707, May 29, 2012).

The control measures that were imposed during the first RHR implementation period established an emissions cap of 3,550 tons of sulfur dioxide (SO_2) per year from the fuel oil-fired boilers at Hawai'i Electric Light's Hill, Shipman and Puna generating stations, beginning in January 1, 2018, at an estimated cost of 7.9 million dollars per year. According to the FIP, this represents a reduction of 1,400 tons per year from the total projected 2018 annual emissions of SO_2 from these facilities. This control measure, in conjunction with SO_2 and NO_X emissions control requirements that are already in place, was found to

[3] The Class I areas in the state of Hawai'i include the Hawai'i Volcanoes National Park on the Hawai'i Island, and Haleakalā National Park on Maui.

ensure that reasonable progress is made during this first planning period toward the national goal of no anthropogenic visibility impairment by 2064 at Hawaiʻi's two Class I areas.

The second implementation planning period (2019-2028) for the national regional haze efforts is currently underway. The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)[4] provides guidance to states for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade (or "anthropogenic") sources of emissions. The EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)[5] provides guidance to states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. The approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions; however, the 2017 RHR defines visibility impairment or anthropogenic visibility impairment as:

> *any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.*

Specifically, the EPA's Visibility Guidance states that although they did not attempt to account for haze formed by natural volcanic emissions:

> *We encourage states with Class I areas affected by volcanic emissions to work with their EPA Regional office to determine an appropriate approach for determining which days are the 20 percent most anthropogenically impaired days.*

In the *5-Year Regional Haze Progress Report for Federal Implementation Plan*[6], the DOH acknowledges the impact of SO_2 from the Kilauea volcano with the following statement:

> *A majority of the visibility degradation is due to the ongoing release of SO_2 from Kilauea volcano with emissions that vary by hundreds of thousands of tons from one year to another. Visibility improvement from significant reductions in Maui and Hawaii Island point source SO_2 is obscured by sulfate from natural volcanic SO_2 that overwhelms sulfate from anthropogenic SO_2 sources.*

Step 1 of the EPA's SIP Guidance is to identify the twenty (20) percent most anthropogenically impaired days and the twenty (20) percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state (40 CFR 51.308(f)(1)). Hawaiian Electric has concerns that this key step may not be accounted for during the second implementation planning period and the development of Hawaiʻi's RHR SIP. The identification of the twenty (20) percent most impaired days sets the foundation for identifying any needed emission reductions.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this the Western Regional Air Partnership (WRAP), with Ramboll US Corporation, reviewed the 2014 National Emissions Inventory (NEI) and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I

[4] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

[5] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010.

[6] 5-Year Regional Haze Progress Report for Federal Implementation Plan, Hawaiʻi State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

area. The WRAP Guidance states that the EPA has concerns over only relying on the Q/d method for screening sources. The EPA points out that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport direction/pathway and dispersion and photochemical processes. To address the EPA's concern, the WRAP subcommittee recommends a second step, application of the weighted emissions potential analysis (WEP).[7] On September 11, 2019, the DOH informed Hawaiian Electric, that Kahe Generating Station (Kahe) was identified as one of the sources potentially contributing to regional haze at the Haleakalā National Park and Volcanoes National Park. This report responds to the DOH September 2019 request to Hawaiian Electric to submit a four-factor analysis for Kahe.

The "Q/d" approach does not take into consideration the frequency or actual visibility impact on the Class I area. In support of the SIP for the first planning period, modeling was conducted for several facilities[8] located on the island of Oahu. Regional haze modeling shows these facilities had an insignificant impact on visibility at Haleakalā and Volcanoes National Parks. Therefore, Hawaiian Electric encourages the DOH to consider actual visibility impacts in the SIP development process.

The SIP Guidance requires that the selection of sources and controls necessary to make reasonable progress must, in addition to the statutory four factors (cost, remaining useful life, etc.), also consider the five required factors listed in 40 CFR section 51.308(f)(2)(iv), and other factors that are reasonable to consider.[9] These additional factors include consideration of emissions reductions due to ongoing air pollution control programs and the anticipated net effect on visibility due to projected changes in source emissions. The Hawaiian Electric and AECOM prepared summary, included in Section 2.2, describes special circumstances applicable in Hawaiʻi that should be considered during the development of the Hawaiʻi Regional Haze SIP.

2.2. ADDITIONAL FACTORS

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances applicable in Hawaiʻi that should be considered during the development of the Hawaiʻi Regional Haze SIP. Significant among those circumstances is Hawaiʻi's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the Regional Haze 2064 target date. These same issues were addressed by the EPA in the FIP and the DOH in their Progress Report that as approved by the EPA, effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report and summarized in the following sections.

2.2.1. Lack of Contribution to Visibility Impairment Due to Prevailing Winds

As noted above, the DOH did not consider actual contribution to visibility impairment when selecting sources for the Four-Factor Analysis, but this is a critical factor in establishing realistic reasonable progress goals for Class I areas. The EPA's FIP for Hawaiʻi for the First Decadal Review (77 FR 61478, October 9, 2012) has already acknowledged the predominant trade winds in Hawaiʻi and thus, did not require controls on upwind sources (i.e., sources on Oahu and Maui).

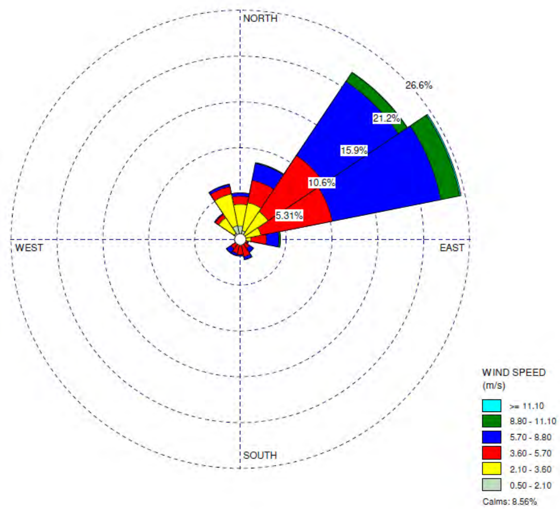
[7] WRAP Reasonable Progress Source Identification and Analysis Protocol For Second 10-year Regional Haze State Implementation Plans, dated February 27, 2019 (https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf).

[8] Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012. Table VI-3 provides visibility modeling results for the following Oahu facilities: Chevron Refinery, Tesoro Refinery, and Hawaiian Electric's Kahe and Waiau power plants.

[9] US EPA Memorandum, "Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program", Dec. 20, 2018, Pages 9, 21, C-1.

The wind rose plot for the Honolulu airport on Oahu shows that the wind is almost always from the northeast and rarely blows from the west or northwest, directions necessary for emissions from Kahe to blow toward either of Hawaiʻi's Class I areas. The Honolulu airport wind rose plot is provided as Figure 2-1 and shows the persistence of the northeasterly trade winds. Based on the infrequent amount of time the wind blows from Kahe toward either of Hawaiʻi's Class I areas, it is unlikely that the facility's potential emissions impact visibility at Haleakalā National Park and Volcanoes National Park. Therefore, when balancing retrofit costs and visibility improvements, the DOH should remain mindful that emissions from this facility are unlikely to contribute to regional haze at Haleakalā National Park and Volcanoes National Park and as such will have no impact on a showing of further reasonable progress.

Figure 2-1. Honolulu Wind Rose (2015 – 2019) Predominant Wind from the Northeast



2.2.2. Lack of Contribution to Visibility Impairment Due to Warm Weather Conditions

The potential for the formation of haze due to NO_X emissions is very low in Hawai'i because of the warm weather conditions year-round. Nitrate haze composition analyses for the Haleakalā and Hawaiʻi Volcanoes National Parks from the IMPROVE web site are included in Appendix B to this report. The data for both national parks show that the contribution of nitrates to haze is very low. It is low as a percentage of the total haze composition, but it is also low as an absolute value for light extinction (visibility impairment). The minimal impact of nitrate haze is clearly illustrated in the Hawaiʻi National Park monitoring data and is much lower than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze which is discussed further in Appendix B to this report.

Due to the low haze impact of NO_X, the DOH should not consider NO_X controls for the Second Decadal Review for Kahe. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_X controls to be material.

2.2.3. Contribution to Visibility Impairment from Volcanic Activity

Volcanic activity on the Hawai‘i Island represents a unique challenge to understanding haze in Hawai’i Class I areas. The Kilauea volcano on Hawai‘i Island has been active for several years, and the levels of SO_2 emissions are being monitored by the United States Geological Survey. In addition to volcanoes being large sources of SO_2, they also emit significant amounts of NO_X. Volcanic activity on Hawai‘i Island is by far the largest source of both SO_2 and NO_X in the state and so dominates visibility impairment to Class I areas as to completely obscure any small impact from anthropogenic sources. Significant portions of direct Particulate Matter (PM) emissions are due to volcanic activity. Whatever small impact of SO_2 NO_X, and PM emissions come from power plants are projected to be phased out well before the end point of the Regional Haze Rule (i.e., 2064) by Hawai‘i’s State Law: Renewable Portfolio Standards (RPS). Thus, the DOH should not consider SO_2, NO_X, or PM controls for the Second Decadal Period Review for Kahe.

2.2.4. Renewable Portfolio Standards

For the reasons stated above and based on AECOM’s analysis, *Appendix C: Hawai‘i’s Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO_2, NO_X, and particulate matter, 10 microns or less in diameter (PM_{10}) emissions from Kahe do not significantly contribute to regional haze at the Class I areas. The low impact that Kahe may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawai‘i Revised Statute (HRS) §269-92) and consistent with the Hawai‘i Clean Energy Initiative (HCEI). Both past and projected future decreases in fossil-fueled electric generating unit (EGU) usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO_2) by 2045. Therefore, further requirements for controls at Kahe would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawai‘i Progress Report for Phase 1), it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO_2 emissions from Kahe do not significantly contribute to regional haze. Additionally, as also mentioned in *Appendix B: Hawaiian Electric Regional Haze Visibility Considerations*, Kahe is not upwind of either of Hawai'i's Class I areas. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 3-1 lists the baseline SO_2 emissions for Kahe.

Table 3-1. Baseline SO_2 Emissions

Unit	Fuel Sulfur [A]	SO_2 Emissions (lb/MMBtu) [B]	SO_2 Emissions (TPY) [C]
K1	0.42%	0.446	841.8
K2	0.42%	0.446	659.5
K3	0.42%	0.446	836.3
K4	0.42%	0.446	859.8
K5	0.42%	0.446	1,136.2
K6	0.42%	0.446	1,431.5
		Total	**5,765.1**

[A] Calendar year 2017 annual average LSFO sulfur content.

[B] The SO_2 emission factor is based on 100% conversion of fuel sulfur to SO_2 and the calendar year 2017 annual average LSFO fuel density (7.93 lb/gal) and higher heating value (149,479 Btu/gal).

[C] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four factors can be analyzed. SO_2 emissions are generated during fuel oil combustion from the oxidation of sulfur contained in the fuel. Available SO_2 control technologies for the Kahe boilers are:

- Flue Gas Desulfurization (FGD)
    - Dry Sorbent Injection (DSI)
    - Spray Dryer Absorber (SDA)
    - Wet Scrubber
    - Circulating Dry Scrubber (CDS)
- Fuel Switching
- Renewable Portfolio Standards (RPS)

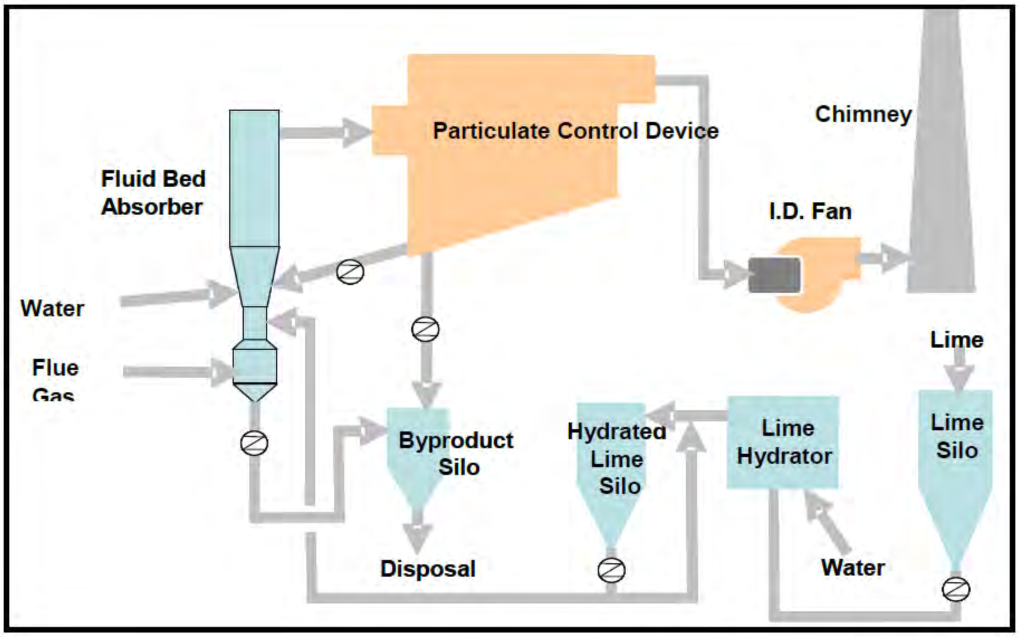
The feasibility of these controls is discussed in the following sections.

3.1.1. Post-Combustion Controls

3.1.1.1. Boilers

An internal engineering study in 2012 identified CDS as the best option, if required, for the Kahe Boilers. The CDS process uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. The process starts when flue gas enters multiple venturi nozzles at the base of a vertical reactor tower, where it is humidified by a water mist before entering the circulating bed of powdered hydrated lime, fly ash, and recycled byproducts. Figure 3-1 shows a typical process flow diagram of a CDS system. The addition of CDS is expected to reduce SO_2 emissions by ninety percent.

Figure 3-1. Typical CDS system



3.1.2. Fuel Switching

The Kahe boilers currently burn residual low sulfur fuel oil with a maximum sulfur content of 0.5 percent by weight. The average sulfur content of the low sulfur fuel oil burned in 2017 was approximately 0.42 percent by weight. Switching to a lower sulfur fuel will reduce SO_2 emissions in proportion to the reduction in fuel sulfur content.[10] However, a lower sulfur residual oil is not currently available in Hawaiʻi. Lower sulfur content distillate fuels are available and could be burned in the boilers or could be blended with the existing residual low sulfur fuel oil to lower the sulfur content. Technically feasible options include blending the current residual low sulfur fuel oil with a lower sulfur distillate fuel or switching to a lower sulfur distillate fuel. The SO_2 four-factor analysis will evaluate both options.

3.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO_2 emissions from Kahe do not significantly contribute to regional haze. The low impact that Kahe may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawaiʻi Revised Statute (HRS) §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress

[10] Natural gas has less sulfur than the existing residual fuel oil. However, natural gas is not a technically feasible option because there is no utility-scale natural gas supply in Hawaiʻi.

goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO_2) by 2045. Therefore, further requirements for controls at Kahe would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawai'i Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, the technically feasible options to reduce SO_2 emissions are:

- CDS;
- Fuel switching to a residual/distillate blended fuel; or
- Fuel switching to a lower sulfur distillate fuel.

For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors are discussed in the following sections.

3.2.1. Cost of Compliance

The cost effectiveness of CDS was based on the annualized cost of the CDS divided by the reduction in SO_2 emissions. The cost effectiveness of the fuel switching was determined by calculating the annual incremental cost of switching to a lower sulfur fuel divided by the reduction in SO_2 emissions. Switching fuel would require changes to the injectors and the fuel system; however, these expenses were not included in the analysis.

Kahe currently purchases low sulfur fuel oil from Par Hawaii Refining, LLC; current fuel costs are based on 2019 fuel purchases. The current residual low sulfur fuel oil is refined on Oahu and changes in quantities of residual low sulfur fuel oil and ULSD would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance.

Table 3-2 presents the cost effectiveness of adding CDS to the boilers. The cost effectiveness is determined by dividing the annualized cost by the annual reduction in SO_2 emissions. The cost effectiveness of adding CDS systems ranges from $15,261 to $21,115 per ton of SO_2 in the different units and the total cost equals 92 million dollars ($92,000,000) annually and 1.4 billon dollars ($1,400,000,000) over fifteen (15) years.

Table 3-3 presents the cost effectiveness of switching the boilers from residual low sulfur fuel oil to a residual low sulfur fuel oil/ULSD blend with a maximum sulfur content of 0.25 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO_2 emissions. The cost effectiveness of switching to a residual low sulfur fuel oil /ULSD blend with a maximum sulfur content of 0.25 percent by weight is $11,357 per ton of SO_2 and would increase fuel cost by 27 million dollars ($27,000,000) annually and 405 million dollars ($405,000,000) over fifteen (15) years.

Table 3-4 presents the cost effectiveness of switching the boilers from residual low sulfur fuel oil to ULSD with a maximum sulfur content of 0.0015 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO_2 emissions. The cost effectiveness of switching the boilers to ULSD with a maximum sulfur content of 0.0015 percent by weight is $9,897 per ton of SO_2 and would increase fuel cost by 57 million dollars ($57,000,000) annually and 855 million dollars ($855,000,000) over fifteen (15) years.

3.2.2. Time Necessary to Achieve Compliance

If the DOH determines that switching fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years. If the DOH determines that CDS systems are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years.

3.2.3. Energy and Non-Air Quality Environmental Impacts

There are no energy and non-air quality environmental impact of compliance for fuel switching. The cost increase associated with fuel switching to a lower sulfur fuel will increase the cost of the electricity produced by Kahe and directly impact the price of electricity for Hawaiian Electric customers.

CDS systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist. In addition, solid waste streams are created that will require disposal.

3.2.4. Remaining Useful Life

The cost of compliance for fuel switching does not contain any capital cost. The remaining useful lives of the boilers do not impact the annualized capital costs of potential controls because the useful lives of the boilers are assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. However, Hawaiian Electric intends to retire the Kahe 5 and 6 boilers in 2028, Kahe 1 and 2 boilers in 2035, and Kahe 3 and 4 boilers in 2039.[11] The retirements of Kahe 1, 2, 5 and 6 may significantly shorten the estimated time the control equipment is used, as calculated in the analysis, and would serve to further increase the removal cost per ton for SO_2.

3.3. SULFUR DIOXIDE CONCLUSION

The cost effectiveness of switching the boilers to a residual low sulfur fuel oil/ULSD blend with a maximum sulfur content of 0.25 percent by weight is $11,400 per ton of SO_2 and would increase fuel cost by 27 million dollars ($27,000,000) annually and 405 million dollars ($405,000,000) over fifteen (15) years. The cost effectiveness of switching the boilers to ULSD with a maximum sulfur content of 0.0015 percent by weight will reduce SO_2 emissions at a cost of $9,900 per ton of SO_2 and would increase fuel cost by 57 million dollars ($57,000,000) annually and 855 million dollars ($855,000,000) over fifteen (15) years. The cost effectiveness of adding CDS systems to boilers exceeds $15,000 per ton of SO_2 and the total cost equals 92 million dollars ($92,000,000) annually and 1.4 billon dollars ($1,400,000,000) over fifteen (15) years. These costs are greater than the BART and reasonable progress thresholds established in the first planning period of $5,600 per ton and $5,500 per ton, respectively.[12]

While there are no fuel changes or add-on controls proposed, other long- term emission reduction strategies, such as those included as part of the Hawaiʻi RPS, are viable alternatives that would create greater benefits.

[11] *Hawaiian Electric Companies' PSIP Update Report*, PUC Docket 2014-0183, December 23, 2016.
[12] *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaiʻi*, U.S. EPA Region 9, May 14, 2012.

Table 3-2. SO_2 Cost effectiveness of CDS

Unit	Control Option	2017 SO_2 Emissions (tpy)	Controlled Emission Level [A] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (ton/yr)	Total Annual Cost [B] ($/yr)	Cost Effectiveness ($/ton)
K1	CDS	841.8	0.045	3,778,041	84.2	757.6	$12,347,786	$16,298
K2	CDS	659.5	0.045	2,959,869	66.0	593.6	$12,532,786	$21,115
K3	CDS	836.3	0.045	3,753,356	83.6	752.7	$13,291,786	$17,660
K4	CDS	859.8	0.045	3,858,826	86.0	773.8	$12,747,786	$16,474
K5	CDS	1,136.2	0.045	5,099,323	113.6	1,022.6	$21,291,819	$20,822
K6	CDS	1,431.5	0.045	6,424,644	143.2	1,288.4	$19,661,819	$15,261

[A] Controlled emission levels based on 90% control.

[B] See Appendix A for total annual cost calculations.

Table 3-3. SO_2 Cost effectiveness of Switching to a Residual/ULSD Blend

Unit	Current Residual Oil (0.50% maximum Sulfur) [A]					Residual/ULSD Blend (0.25% maximum Sulfur) [B]						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO_2 Emissions (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (tpy)	Fuel Cost Differential [C] ($/Gal)	Fuel Cost Differential [C] ($/yr)	SO_2 Cost Effectiveness ($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	143,071	26,406,754	493.0	348.8	0.15	$3,961,013	11,357
K2	0.42%	149,479	19,801,237	2,959,869	659.5	143,071	20,688,114	386.3	273.2	0.15	$3,103,217	11,357
K3	0.42%	149,479	25,109,590	3,753,356	836.3	143,071	26,234,222	489.8	346.5	0.15	$3,935,133	11,357
K4	0.42%	149,479	25,815,168	3,858,826	859.8	143,071	26,971,403	503.6	356.2	0.15	$4,045,710	11,357
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	143,071	35,641,903	665.5	470.7	0.15	$5,346,285	11,357
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	143,071	44,905,284	838.4	593.1	0.15	$6,735,793	11,357

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on a blend of 50.0% residual oil and 50.0% ULSD and the weighted averge of the 2017 fuel HHV and density for residual oil and ULSD, and contract fuel sulur limits.

[C] Based on actual fuel purchases by Hawaiian Electric.

Table 3-4. SO_2 Cost effectiveness of Switching to ULSD

Unit	Current Residual Oil (0.50% maximum Sulfur) [A] 2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO_2 Emissions (tpy)	ULSD (0.0015% maximum Sulfur) [B] Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (tpy)	Fuel Cost Differential [C] ($/Gal)	Fuel Cost Differential [C] ($/yr)	SO_2 Cost Effectiveness ($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	136,662	27,645,144	3.8	838.0	0.30	$8,293,543	9,897
K2	0.42%	149,479	19,801,237	2,959,869	659.5	136,662	21,658,318	3.0	656.5	0.30	$6,497,496	9,897
K3	0.42%	149,479	25,109,590	3,753,356	836.3	136,662	27,464,521	3.8	832.5	0.30	$8,239,356	9,897
K4	0.42%	149,479	25,815,168	3,858,826	859.8	136,662	28,236,273	3.9	855.9	0.30	$8,470,882	9,897
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	136,662	37,313,391	5.1	1,131.1	0.30	$11,194,017	9,897
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	136,662	47,011,195	6.4	1,425.1	0.30	$14,103,358	9,897

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

[C] Based on actual fuel purchases by Hawaiian Electric.

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_X emissions from Kahe do not significantly contribute to regional haze. Additionally, as also mentioned in *Appendix B: Hawaiian Electric Regional Haze Visibility Considerations*, Kahe is not upwind of either of Hawai'i's Class I areas. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 4-1 lists the baseline NO_X emissions for Kahe.

Table 4-1. Baseline NO_X Emissions

	NO_X Emissions		
Unit	**LSFO Emission Factor (lb/MMBtu) [A]**	**Adjusted Emission Factor (lb/MMBtu) [B]**	**(TPY) [C]**
K1	0.491	0.494	932.7
K2	0.647	0.651	963.0
K3	0.350	0.353	661.7
K4	0.337	0.379	732.2
K5	0.797	0.802	2,044.2
K6	0.195	0.196	630.1
		Total	**5,963.9**

[A] Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

[B] The adjusted emission factors include emissions from the ignition fuels and used oil.

[C] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

4.1. NITROGEN OXIDES CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four factors can be analyzed. NO_X is 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 versus combustion air) has led to the use of the terms "thermal NO_X" and "fuel NO_X" when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized by high combustion temperatures. Fuel NO_X emissions are created by the oxidation of nitrogen contained in the fuel. Fuel NO_X emissions from firing residual oil are greater than fuel NO_X from firing diesel. NO_X emissions from residual oil can be up to fifty percent fuel NO_X.[13]

The formation of NO_X compounds in utility boilers is sensitive to the method of firing and combustion controls utilized. Nitrogen oxide (NO) is typically the predominant form of NO_X emissions from fossil fuel combustion, with the remaining NO_X being in the form of nitrogen dioxide (NO_2). The NO_2/NO_X in-stack ratio for boilers is typically less than ten percent.

Available NO_X control technologies for the boilers are categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the furnace, which minimizes NO_X formation. K6 is currently equipped with combustion controls to reduce NO_X emissions.

[13] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.3.

Post-combustion controls convert NO_X in the flue gas to molecular nitrogen and water. Available NO_X control technologies for the boilers are:

- Combustion Controls (K1 – K5)
  - Flue Gas Recirculation (FGR)
  - Overfire Air (OFA)
  - Low NO_X Burners (LNB)
- Post-Combustion Controls (K1 – K6)
  - Selective Catalytic Reduction (SCR)
  - Selective Non-Catalytic Reduction (SNCR)
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

4.1.1. Combustion Controls

4.1.1.1. Flue Gas Recirculation (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_X formation. When FGR is operated without additional controls, the NO_X control range for wall-fired boilers (K1, K2, and K5) with FGR is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[14] This control is a technically feasible option for the Kahe boilers.

4.1.1.2. Overfire Air (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. When OFA is operated without additional controls, the NO_X control range for wall-fired boilers (K1, K2, and K5) is approximately 0.30-0.45 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.20-0.30 lb/MMBtu.[15] This control is a technically feasible option for the Kahe boilers.

4.1.1.3. Low NO_X Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame

[14] *Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler*, EPA, 1994.
[15] Ibid.

temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

The estimated NO_X control range for LNBs on wall-fired boilers (K1, K2, and K5) is approximately 0.25-0.35 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[16] When combined with OFA, the estimated NO_X control range on wall-fired boilers (K1, K2, and K5) is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[17] LNB systems and LNB systems with OFA are technically feasible for the Kahe boilers.

4.1.2. Post Combustion Controls

4.1.2.1. Selective Catalytic Reduction (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

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

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, catalyst, ammonia storage, and an ammonia injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The estimated NO_X control range for SCR is approximately 0.05-0.10 lb/MMBtu for a wall-fired boiler (K1, K2, and K5), and for tangentially-fired boilers (K3 and K4) is approximately 0.03-0.10 lb/MMBtu.[18] This control is a technically feasible option for the Kahe boilers.

4.1.2.2. Selective Non-Catalytic Reduction (SNCR)

In SNCR systems, a reagent (ammonia or urea) is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent 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-based SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. The estimated NO_X control range for SNCR for wall-fired boilers (K1, K2, and K5) is approximately 0.30-0.40 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.20-0.25 lb/MMBtu.[19] This control is a technically feasible option for the Kahe boilers.

4.1.3. Rank of Technically Feasible NO_X Boiler Control Options by Effectiveness

The next step is to rank the technically feasible options according to effectiveness. Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

[16] Ibid.
[17] Ibid.
[18] Ibid.
[19] Ibid.

Table 4-2. Control Effectiveness of Technically Feasible NO_X Control Technologies

	Estimated Controlled Level	
	Wall-Fired Boilers	Tangentially-Fired Boilers
Control Technology	(lb/MMBtu)	(lb/MMBtu)
SCR	0.05 - 0.10	0.03 - 0.10
LNB & OFA	0.25 - 0.30	0.15 - 0.20
FGR	0.25 - 0.30	0.15 - 0.20
LNB	0.25 - 0.35	0.15 - 0.20
SNCR	0.30 - 0.40	0.20 - 0.25
OFA	0.30 - 0.45	0.20 - 0.30

The control levels in Table 4-2 are presented as a range. This is due to the specific level of control that is achievable for the Kahe boilers based on the application of the controls listed in Table 4-2 is unknown. It is anticipated that combustion controls such as LNB with OFA and possibly LNB alone can achieve NO_X emission levels of approximately 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4. As noted in Table 4-1, the Kahe boilers are currently emitting in the range of 0.196 lb/MMBtu to 0.802 lb/MMBtu. Further, it is believed that SCR can achieve a NO_X emissions level of approximately 0.10 lb/MMBtu.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, LNB with OFA and SCR are the best feasible options to reduce NO_X emissions from the boilers. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for adding NO_X controls are discussed in the following sections.

4.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of LNB with OFA and SCR have been estimated for the boilers. The cost effectiveness of LNB with OFA is based on a controlled NO_X emissions level of 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4. At this time, it is unknown if LNBs alone can achieve this level of emissions or if LNB combined with OFA would be required to meet this level. Therefore, the costing is based on LNB with OFA, it is assumed that a NO_X emissions level of 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4 can be achieved with LNB with OFA. This level of NO_X emissions is comparable to SNCR; the only other control expected to result in lower achievable NO_X emissions is SCR. The cost effectiveness of SCR is based on a controlled NO_X emissions level of 0.10 lb/MMBtu.

Table 4-3 presents a summary of the cost effectiveness of adding LNB with OFA and SCR to the boiler. The cost effectiveness is determined by dividing the annual cost by the annual reduction in NO_X emissions. The cost effectiveness of LNB with OFA ranges from $634 per ton to over $1,675 per ton of NO_X emissions in the different units and the total cost equals 3 million dollars ($3,000,000) annually and 45 million dollars ($45,000,000) over fifteen (15) years. The cost effectiveness of SCR ranges from $2,078 per ton to $11,840 per ton of NO_X emissions in the different units and the total cost equals 18 million dollars ($18,000,000) annually and 270 million dollars ($270,000,000) over fifteen (15) years.

Table 4-3. NO_X Cost effectiveness of LNB with OFA and SCR

Unit	Control Option	2017 NO_X Emissions (tpy)	Controlled Emission Level [A] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_X Emissions (tpy)	NO_X Reduced (ton/yr)	Total Annual Cost [B] ($/yr)	Cost Effectiveness ($/ton)
K1	LNB w/OFA	932.7	0.30	3,778,041	566.7	366.0	$612,900	$1,675
	SCR	932.7	0.10	3,778,041	188.9	743.8	$2,708,372	$3,641
K2	LNB w/OFA	963.0	0.30	2,959,869	444.0	519.0	$596,013	$1,148
	SCR	963.0	0.10	2,959,869	148.0	815.0	$2,574,564	$3,159
K3	LNB w/OFA	661.7	0.20	3,753,356	375.3	286.4	$444,186	$1,551
	SCR	661.7	0.10	3,753,356	187.7	474.0	$2,669,012	$5,630
K4	LNB w/OFA	732.2	0.20	3,858,826	385.9	346.3	$447,598	$1,292
	SCR	732.2	0.10	3,858,826	192.9	539.3	$2,704,056	$5,014
K5	LNB w/OFA	2,044.2	0.30	5,099,323	764.9	1,279.3	$810,691	$634
	SCR	2,044.2	0.10	5,099,323	255.0	1,789.2	$3,718,061	$2,078
K6	SCR	630.1	0.10	6,424,644	321.2	308.9	$3,656,850	$11,840

[A] Controlled emission levels based on "Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler" EPA, 1994.

[B] See Appendix A for total annual cost calculations.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress, it is anticipated that these changes could be implemented within three to five years.

4.2.3. Energy and Non-Air Quality Environmental Impacts

SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR can potentially cause significant environmental impacts related to the storage of ammonia, and the storage of aqueous ammonia above 10,000 pounds is regulated by the EPA's Risk Management Program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia. Ammonia released from SCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

4.2.4. Remaining Useful Life

The remaining useful lives of the boilers do not impact the annualized capital costs of potential controls because the useful lives of the boilers are assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. However, Hawaiian Electric intends to retire the Kahe 5 and 6 boilers in 2028, Kahe 1 and 2 boilers in 2035, and Kahe 3 and 4 boilers in 2039.[20] Although the plan is not binding with respect to specific dates, this is a necessary step to meet Hawaiʻi's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. The retirements of Kahe 1, 2, 5 and 6 may significantly shorten the estimated time the control equipment is used, as calculated in the analysis, and would serve to further increase the removal cost per ton for NO_X.

4.3. NITROGEN OXIDES CONCLUSION

The cost effectiveness of adding LNB with OFA to the Kahe boilers ranges from $600 per ton to $1,700 per ton of NO_X in the different units and the total cost equals 3 million dollars ($3,000,000) annually and 45 million dollars ($45,000,000) over fifteen (15) years. These costs are similar to the BART analyses conducted for the first planning period. For the first planning period, the EPA concluded the emission reductions provided by LNB are unlikely to provide a measurable visibility benefit at Hawaiʻi Volcanoes National Park or Haleakalā National Park.[21]

The cost effectiveness of SCR to the Kahe boilers ranges from $2,100 per ton to $11,800 per ton of NO_X in the different units and the total cost equals 18 million dollars ($18,000,000) annually and 270 million dollars ($270,000,000) over fifteen (15) years. These costs are similar to the BART analyses conducted for the first planning period. For the first planning period, the EPA concluded that SCR was not cost effective.[22]

[20] *Hawaiian Electric Companies' PSIP Update Report, PUC Docket 2014-0183, December 23, 2016.*
[21] *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaiʻi*, U.S. EPA Region 9, May 14, 2012.
[22] Ibid.

The results of the four-factor analysis are consistent with the conclusions, that NO_X controls are not required, reached for the first planning period. Therefore, Hawaiian Electric does not propose any NO_X emissions reduction measures in addition to its RPS program to meet the RHR requirements.

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM_{10} emissions from Kahe do not significantly contribute to regional haze. Additionally, as also mentioned in *Appendix B: Hawaiian Electric Regional Haze Visibility Considerations*, Kahe is not upwind of either of Hawai'i's Class I areas. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019 calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 5-1 lists the baseline PM_{10} emissions for Kahe.

Table 5-1. Baseline PM_{10} Emissions

	PM_{10} Emissions		
Unit	**LSFO Emission Factor (lb/MMBtu) [A]**	**Adjusted Emission Factor (lb/MMBtu) [B]**	**(TPY) [C]**
K1	0.0293	0.0295	55.7
K2	0.0264	0.0266	39.3
K3	0.0274	0.0275	51.7
K4	0.0260	0.0262	50.5
K5	0.0307	0.0309	78.7
K6	0.0336	0.0338	108.6
		Total	**384.5**

[A] Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

[B] The adjusted emission factors include emissions from the ignition fuels and used oil.

[C] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

5.1. PARTICULATE MATTER CONTROL OPTIONS

The Kahe boilers are subject to the Electric Utility Steam Generating Units Maximum Achievable Control Technology (EGU MACT) standards (40 CFR Part 63, Subpart UUUUU). Under the EGU MACT standards, the Kahe boilers are subject to the filterable PM emission limit of 0.030 lb/MMBtu on a thirty-boiler operating day rolling average for non-continental liquid oil-fired units. Currently, the Kahe boilers are meeting the filterable PM emission limit. Due to these low levels of PM emissions, additional post-combustion controls are not expected to be cost effective. Therefore, the four-factor analysis was not conducted for the Kahe boilers.

5.2. FOUR-FACTOR ANALYSIS AND CONCLUSION

PM_{10} baseline emissions are fifteen times lower than SO_2 and NO_X baseline emissions. Due to these low levels of PM emissions, additional post-combustion controls are not expected to be cost effective and any reductions are expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for the Kahe Boilers. Therefore, Hawaiian Electric does not propose any PM_{10} emissions reduction measures in addition to its RPS program to meet the RHR requirements.

Appendix Table A-1. CDS Capital and O&M Cost Estimate

Unit	K1	K2	K3	K4	K5	K6
MW Rating (Nominal)	92	90	92	93	142	142
Classification	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Capital Cost						
Direct Costs						
Total Direct Costs (DC)	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 61,988,000	$ 61,988,000
Indirect Costs						
Summary of Indirect Costs not including Contingency	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 19,142,000	$ 19,142,000
Contingencies	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 21,468,000	$ 21,468,000
Total Indirect Costs (IC)	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 40,610,000	$ 40,610,000
Allowance for Funds Used During Construction (AFDC)	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 10,466,000	$ 10,466,000
Total Capital Investment (TCI)	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 113,064,000**	**$ 113,064,000**
Annual Cost						
Direct Annual Costs						
Fixed Annual Costs						
Maintenance labor and materials	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Total Fixed Annual Costs	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Variable Annual Costs						
Byproduct disposal	$ 273,000	$ 294,000	$ 377,000	$ 314,000	$ 478,000	$ 352,000
Reagent Cost (lime)	$ 632,000	$ 679,000	$ 864,000	$ 740,000	$ 1,582,000	$ 1,204,000
Water Cost	$ 51,000	$ 54,000	$ 69,000	$ 58,000	$ 116,000	$ 88,000
Power (ID and Aux) Cost	$ 1,561,000	$ 1,675,000	$ 2,151,000	$ 1,805,000	$ 4,259,000	$ 3,161,000
Total Variable Annual Costs	$ 2,517,000	$ 2,702,000	$ 3,461,000	$ 2,917,000	$ 6,435,000	$ 4,805,000
Total Direct Annual Costs (DAC)	$ 4,305,000	$ 4,490,000	$ 5,249,000	$ 4,705,000	$ 8,878,000	$ 7,248,000
Indirect Annual Costs						
Cost for capital recovery [2]	$ 8,042,786	$ 8,042,786	$ 8,042,786	$ 8,042,786	$ 12,413,819	$ 12,413,819
Total Indirect Annual Costs (IDAC)	$ 8,042,786	$ 8,042,786	$ 8,042,786	$ 8,042,786	$ 12,413,819	$ 12,413,819
Total Annual Cost (TAC)	**$ 12,347,786**	**$ 12,532,786**	**$ 13,291,786**	**$ 12,747,786**	**$ 21,291,819**	**$ 19,661,819**

[1] Costing from an Hawaiian Electric internal study dated July 2012.

[2] Capital Recovery Factor (CRF) = [I x (1+i)^a]/[(1+i)^a - 1]   CRF = 0.11

Where:

I = Interest Rate (7% interest)

a = Equipment life (15 yrs)

Appendix Table A-2. LNB with OFA Capital and O&M Cost Estimate

Parameters/Costs	Equation	K1	K2	K3	K4	K5
Boiler design capacity, mmBtu/hr (C)		903	900	892	918	1468
Boiler Type		Normal	Normal	Tangential	Tangential	Normal
2017 Annual Heat Input, MMBtu/yr (H)		3,778,041	2,959,869	3,753,356	3,858,826	5,099,323
Unit Size, kW (kW)		92,000	90,000	92,000	93,000	142,000
Unit Size, MW (MW)		92.0	90.0	92.0	93.0	142.0
Capital recovery factor						
a. Equipment CRF, 15-yr life, 7% interest	= [I x (1+i)^a]/[(1+i)^a - 1] where I = interest rate, a = equipment life	0.11	0.11	0.11	0.11	0.11
Cost Index (CI) [A]						
a. 2018	603.1					
b. 2004	444.2					
Total Capital Investment [B,C]						
TCI ($)	=$24/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall =$18/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$4,582,437	$4,518,331	$3,436,828	$3,460,727	$6,052,369
Direct Annual Operating Costs $/yr						
Variable O&M Costs [D]	=($0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Wall $0.03 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Tangential	$41,036	$32,149	$15,288	$15,718	$55,388
Indirect Annual Costs, $/yr						
1. Fixed O&M Costs [E]	= $0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall = $0.27/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$68,737	$67,775	$51,552	$51,911	$90,786
2. Capital recovery	= Equipment CRF x TCI	$503,127	$496,088	$377,345	$379,969	$664,518
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$612,900**	**$596,013**	**$444,186**	**$447,598**	**$810,691**

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region,* dated September 6, 2005. The cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

[A] Cost Index: Chemical Engineering Plant Cost Index (CEPCI). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019.

[B] TCI for LNB and LNB w/over fire air ranges from $6/kW to $24/kW for wall boilers and $10/kW to $18/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location.

[C] Scaling factor = (300/Nameplate capacity)^0.359

[D] The variable O&M costs for LNB and LNB w/over fire air ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr for wall boilers and 0.027 mills/kW-hr to 0.03 mills/kW-hr for tangential boilers, the high end of the range was used due to Hawai'i's remote location.

[E] The fixed O&M costs for LNB and LNB w/over fire air ranges from $0.09/kW to $0.36/kW for wall boilers and $0.15/kW to $0.27/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location.

Attachment Table A-3a. Kahe K1 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	384,917	MWhs
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Attachment Table A-3a. Kahe K1 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.494 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	15 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Attachment Table A-3a. Kahe K1 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Attachment Table A-3a. Kahe K1 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		384,917	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.478	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	79.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	355.55	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	743.80	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	418,214	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	111.61	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,746.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	436	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Attachment Table A-3a. Kahe K1 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	501	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.4	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	138	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	476	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	64	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	45,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	511.08	kW

Attachment Table A-3a. Kahe K1 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,416,366	in 2018 dollars

Attachment Table A-3a. Kahe K1 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$792,382 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,915,990 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,708,372 in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,082 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$78,028 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,069 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$88,203 in 2018 dollars
Direct Annual Cost =		$792,382 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,673 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,912,317 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,915,990 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,708,372 per year in 2018 dollars
NOx Removed =	744 tons/year
Cost Effectiveness =	$3,641 per ton of NOx removed in 2018 dollars

Appendix Table A-3b. Kahe K2 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	90	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	295,987	MWhs
Enter the net plant heat input rate (NPHR)	10.0000	MMBtu/MW

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

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

Plant Elevation 10 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Appendix Table A-3b. Kahe K2 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.651 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	15 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft³/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3b. Kahe K2 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	900	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	788,400	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		295,987	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.375	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3289	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	84.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	495.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	815.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	416,824	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	101.67	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,099.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	434	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	499	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.3	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	193	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	664	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	89	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	63,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	504.00	kW

Appendix Table A-3b. Kahe K2 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,169,319	in 2018 dollars

Appendix Table A-3b. Kahe K2 - SCR Costing

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$685,715	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,888,849	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,574,564	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$85,847	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$85,498	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$417,862	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$96,508	in 2018 dollars
Direct Annual Cost =		$685,715	in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,658	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,885,191	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,888,849	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,574,564	per year in 2018 dollars
NOx Removed =	815	tons/year
Cost Effectiveness =	$3,159	per ton of NOx removed in 2018 dollars

Appendix Table A-3c. Kahe K3 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	387,117	MWhs
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Appendix Table A-3c. Kahe K3 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.353 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	15 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 (541.7 2016 CEPCI)	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3c. Kahe K3 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		387,117	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	71.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	225.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	474.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.90		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	413,119	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	126.44	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,267.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	430	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	495	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	302	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	508.40	kW

Appendix Table A-3c. Kahe K3 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,416,366	in 2018 dollars

Appendix Table A-3c. Kahe K3 - SCR Costing

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$753,022	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,915,990	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,669,012	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,082	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$49,728	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,302	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}/R_{layer}$) x FWF	$76,910	in 2018 dollars
Direct Annual Cost =		$753,022	in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,673	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,912,317	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,915,990	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,669,012	per year in 2018 dollars
NOx Removed =	474	tons/year
Cost Effectiveness =	$5,630	per ton of NOx removed in 2018 dollars

Appendix Table A-3d. Kahe K4 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	93	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	390,927	MWhs
Enter the net plant heat input rate (NPHR)	9.8710	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Appendix Table A-3d. Kahe K4 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.379	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	15	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3d. Kahe K4 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	918	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	814,680	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		390,927	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.99		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4204	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	73.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	256.58	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	539.26	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.92		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	425,161	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	122.82	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,461.60	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	443	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	509	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	100	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	344	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	46	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	33,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	517.90	kW

Appendix Table A-3d. Kahe K4 - SCR Costing

Cost Estimate
Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:
$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$
For Oil and Natural Gas-Fired Utility Boilers >500 MW:
$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :
$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :
$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:
$TCI = 5,700 \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:
$TCI = 7,640 \times Q_B \times ELEVF \times RF$

Total Capital Investment (TCI) =	$17,539,183	in 2018 dollars

Appendix Table A-3d. Kahe K4 - SCR Costing

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$774,574	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,929,483	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,704,056	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,696	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$56,571	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$548,821	in 2018 dollars
Annual Catalyst Replacement Cost =		$81,486	in 2018 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$774,574	in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,680	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,925,802	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,929,483	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,704,056	per year in 2018 dollars
NOx Removed =	539	tons/year
Cost Effectiveness =	$5,014	per ton of NOx removed in 2018 dollars

Appendix Table A-3e. Kahe K5 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	493,259	MWhs
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Plant Elevation: 10 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Appendix Table A-3e. Kahe K5 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.802	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	15	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3e. Kahe K5 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		493,259	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.397	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	87.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1030.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,789.23	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.09		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	679,886	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	94.77	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,173.70	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	708	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	814	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	28.5	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	400	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,381	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	184	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	132,800	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	806.65	kW

Appendix Table A-3e. Kahe K5 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$23,093,134	in 2018 dollars

Appendix Table A-3e. Kahe K5 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,178,421	in 2018 dollars
Indirect Annual Costs (IDAC) =	$2,539,640	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$3,718,061	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$115,466	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$187,699	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$706,389	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$168,868	in 2018 dollars
Direct Annual Cost =		$1,178,421	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,014	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,535,626	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,539,640	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,718,061	per year in 2018 dollars
NOx Removed =	1,789	tons/year
Cost Effectiveness =	$2,078	per ton of NOx removed in 2018 dollars

Appendix Table A-3f. Kahe K6 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Utility	**What type of fuel does the unit burn?**	Fuel Oil
Is the SCR for a new boiler or retrofit of an existing boiler?	Retrofit		
Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.5	* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.	

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	601,781	MWhs
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Appendix Table A-3f. Kahe K6 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.196 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	15 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3f. Kahe K6 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Default bank prime rate	

Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		601,781	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.484	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	49.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	145.76	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	308.87	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.61		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	702,117	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	173.00	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,058.46	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	731	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	841	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	29.0	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	48	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	57	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	195	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	26	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	18,800	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.1098

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	817.89	kW

Appendix Table A-3f. Kahe K6 - SCR Costing

Cost Estimate
Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:
$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$
For Oil and Natural Gas-Fired Utility Boilers >500 MW:
$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :
$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :
$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:
$TCI = 5,700 \times Q_B \times ELEVF \times RF$
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:
$TCI = 7,640 \times Q_B \times ELEVF \times RF$

Total Capital Investment (TCI) =	$23,093,134	in 2018 dollars

Appendix Table A-3f. Kahe K6 - SCR Costing

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,117,210 in 2018 dollars
Indirect Annual Costs (IDAC) =	$2,539,640 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$3,656,850 in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$115,466 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$32,402 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$873,807 in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$95,536 in 2018 dollars
Direct Annual Cost =		$1,117,210 in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,014 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,535,626 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,539,640 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,656,850 per year in 2018 dollars
NOx Removed =	309 tons/year
Cost Effectiveness =	$11,840 per ton of NOx removed in 2018 dollars

Appendix B:
Hawaiian Electric Regional Haze Visibility Considerations

Fifth Factor Considerations for SO_2, NOx, and PM Controls

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March 31, 2020

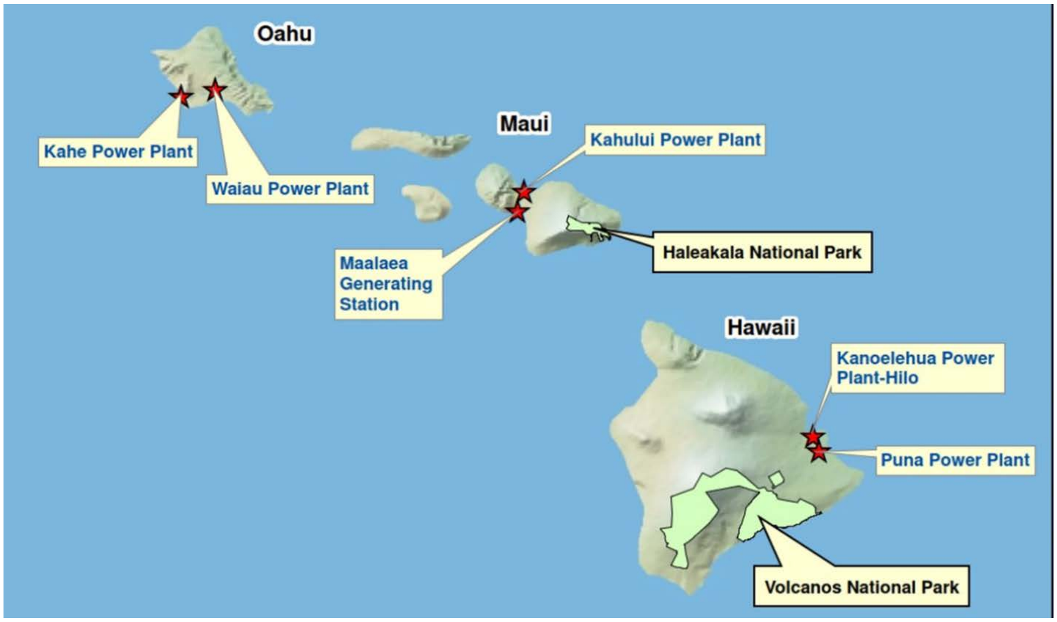
haze precursors for Hawaiʻi due to the unique NOx haze chemistry and climate, leaving SO_2 as the primary precursor pollutant for haze. Hawaiian Electric requests that the DOH make this proposal to the EPA.

5) In the recent past, volcanic activity on Hawaiʻi Island has produced as much as 2 million tons of SO_2 emissions per year[2,3] (emissions vary yearly), as well as roughly 125,000 tons of NOx emissions per year[4]. These volcanic SO_2 emissions are about three orders of magnitude (approximately 1,000 times) greater than anthropogenic SO_2 emissions. Although the IMPROVE monitors indicate that sulfate haze is the most important haze species, it is evident from monthly haze trends and the likelihood of winds from the volcanic activity reaching the IMPROVE monitors that the overwhelming sulfate haze influence comes from natural sources (i.e., volcanic activity).

The locations of the affected Hawaiian Electric sources and the two national parks are shown in Figure B-1. The remainder of this appendix presents details of the above issues and recommendations for how this information should be considered in selection of facilities for Four-Factor analyses and for evaluating potential pollutant control options.

[2] Information on the volcanic SO_2 emissions in 2014 was provided by the EPA in their SO_2 National Ambient Air Quality Technical Support Document at EPA's 2016 SO_2 NAAQS TSD, at https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.
[3] Information on 2014-2017 volcanic SO_2 emissions is available in this journal article: Elias T, Kern C, Horton KA, Sutton AJ and Garbeil H. (2018) Measuring SO_2 Emission Rates at Kīlauea Volcano, Hawaii, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full.
[4] The 125,000 tons per year of NOx assumes NOx emissions rate equals 6% of SO_2 emissions rate. The 6% is derived from worldwide volcanic NOx emissions estimate of 1.0 Teragram ("Tg" – trillion grams)/year ("yr") nitric oxide ("NO") (or 1.5 Tg/yr NO2) from https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article and worldwide volcanic SO2 estimate of 23 Tg/yr from https://www.nature.com/articles/srep44095.

Figure B-1:
Location of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas



2. EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"[5] in August 2019. This guidance allows states to consider, as part of its consideration of emission controls to include for the Second Decadal Review a "5th factor" which involves consideration of visibility impacts of candidate control options. A companion document[6] issued in September 2019 that involves the EPA's visibility modeling results for 2028 is entitled, "Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling".

On Page 11 of the August 2019 guidance, the EPA states:

> *"When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors."* . . .

[5] Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[6] Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

"Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants"

Further, on Page 36 and 37, the EPA states:

"Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal." . . .

". . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."

Consequently, the extremely low likelihood for impact to Class I visibility impairment from control of certain facility pollutants and the plant locations relative to the Class I areas is appropriate for consideration when evaluating the need for further control of these emissions for Regional Haze Reasonable Progress.

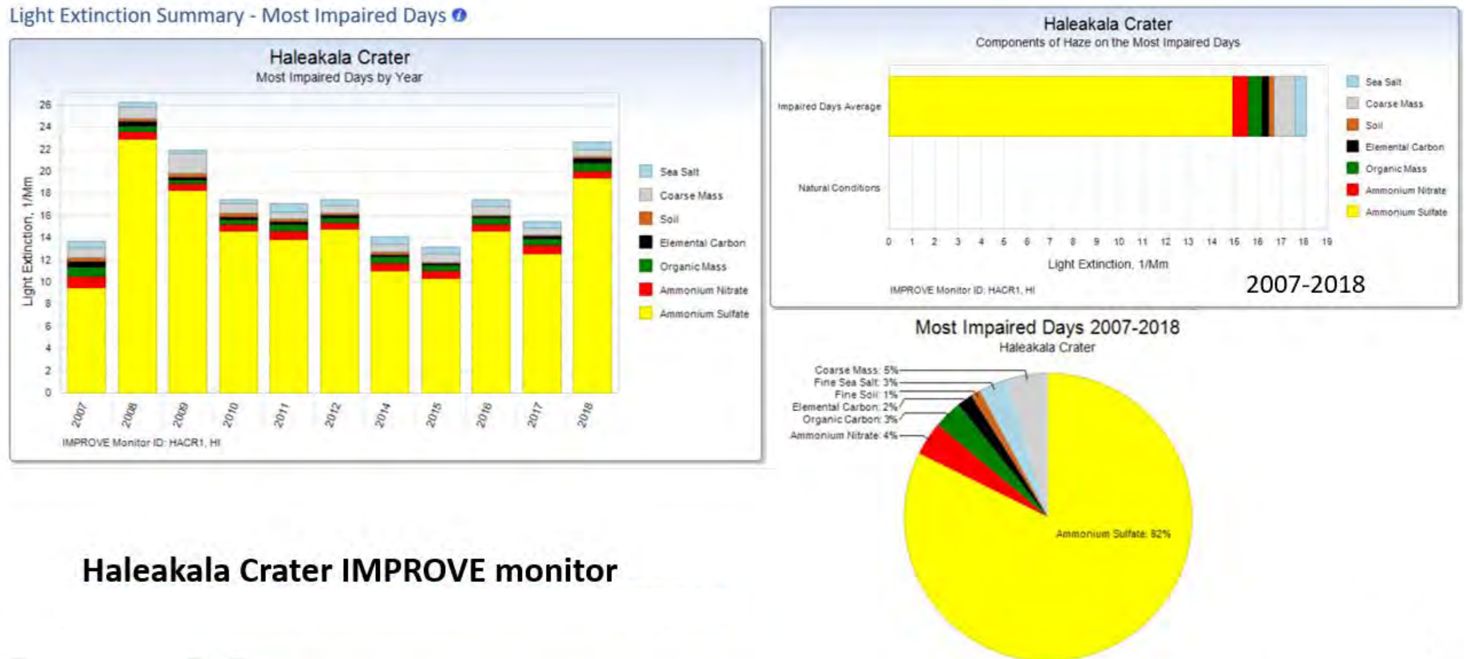
3. Nitrate Haze Composition Analysis

Nitrate haze composition analyses for the Haleakalā and Hawaiʻi Volcanoes National Parks are available at the IMPROVE web site at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/. Figure B-2 provides various charts for the haze species composition at the Haleakalā Crater IMPROVE site, and Figure B-3 provides a time series of stacked bars by species for a recent year at that site. Figures B-4 and B-5 provide similar information for the Hawaiʻi Volcanoes IMPROVE site. Note that these figures show information for the worst 20 percent ("%") impaired days, which is the focus of the RHR for reducing haze. The goal for each decadal review is to track the progress of haze reduction for the worst 20% impaired days; reviewing the composition of haze on these days is a key element in understanding what precursor pollutants to control to achieve the goal.

The data for both National Parks shows that the contribution of nitrates to haze is very low as a percentage of the total, but it is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter ("Mm^{-1}"), equivalent to approximately 0.25 deciview ("dv"), or less. This is the impairment at these monitors due to ALL sources, natural and anthropogenic, and as noted below, the volcanic emissions are much greater than the entire state's anthropogenic NOx emissions for recent years with SO_2 volcanic emissions of roughly 2 million tons per year ("TPY").

The minimal impact of nitrate haze is clearly illustrated in the Hawaiʻi National Park monitoring data and is much smaller than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze, as discussed below.

Figure B-2: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Haleakalā Crater IMPROVE Site



Data source for Figures B-2 through B-5: http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum.

Figure B-3: Time Series of 2018 Daily Haze Extinction Composition Plots for the Haleakalā Crater IMPROVE Site

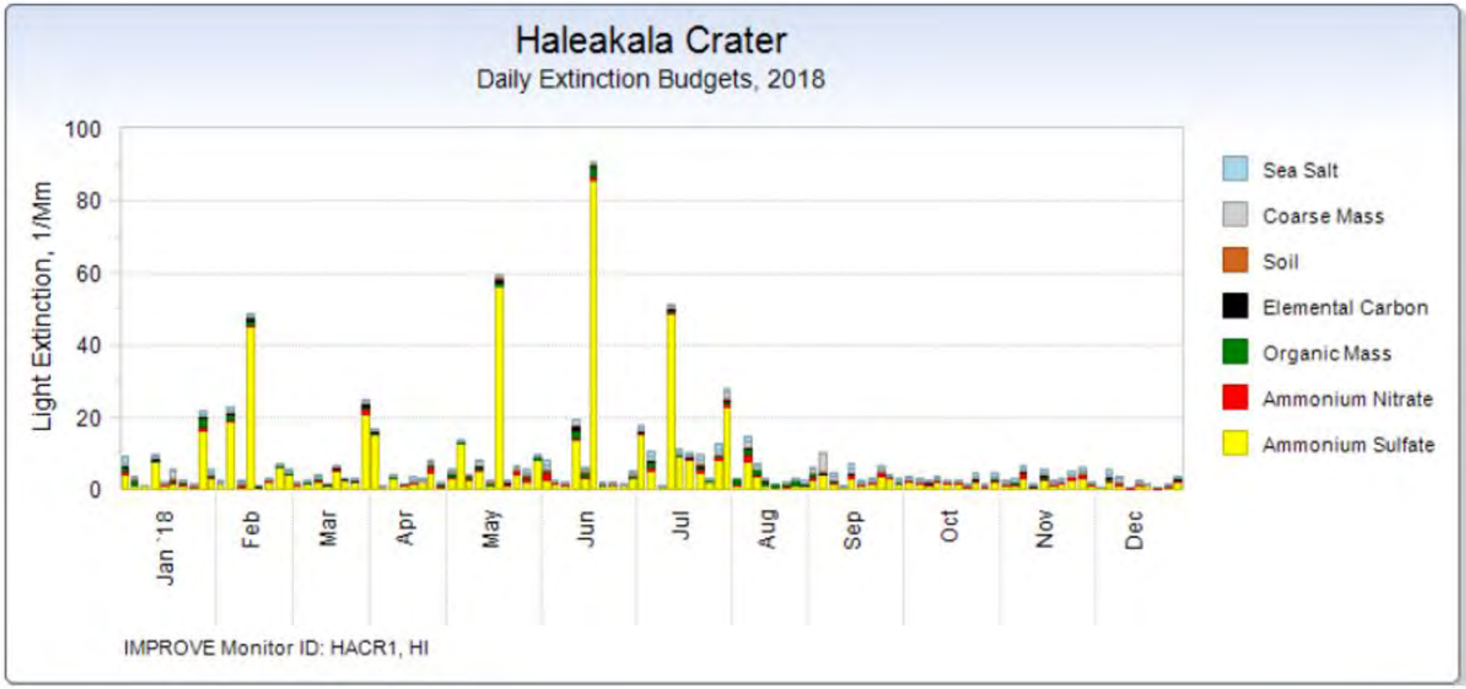


Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site

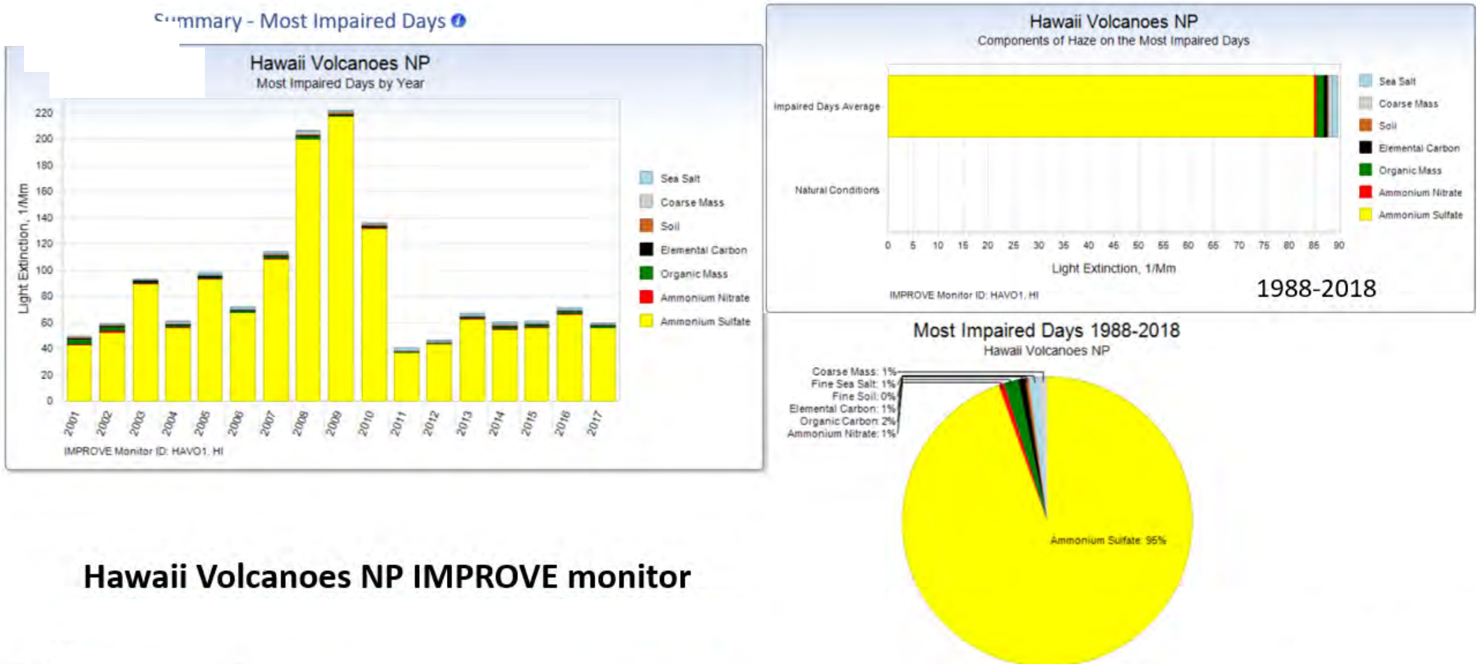
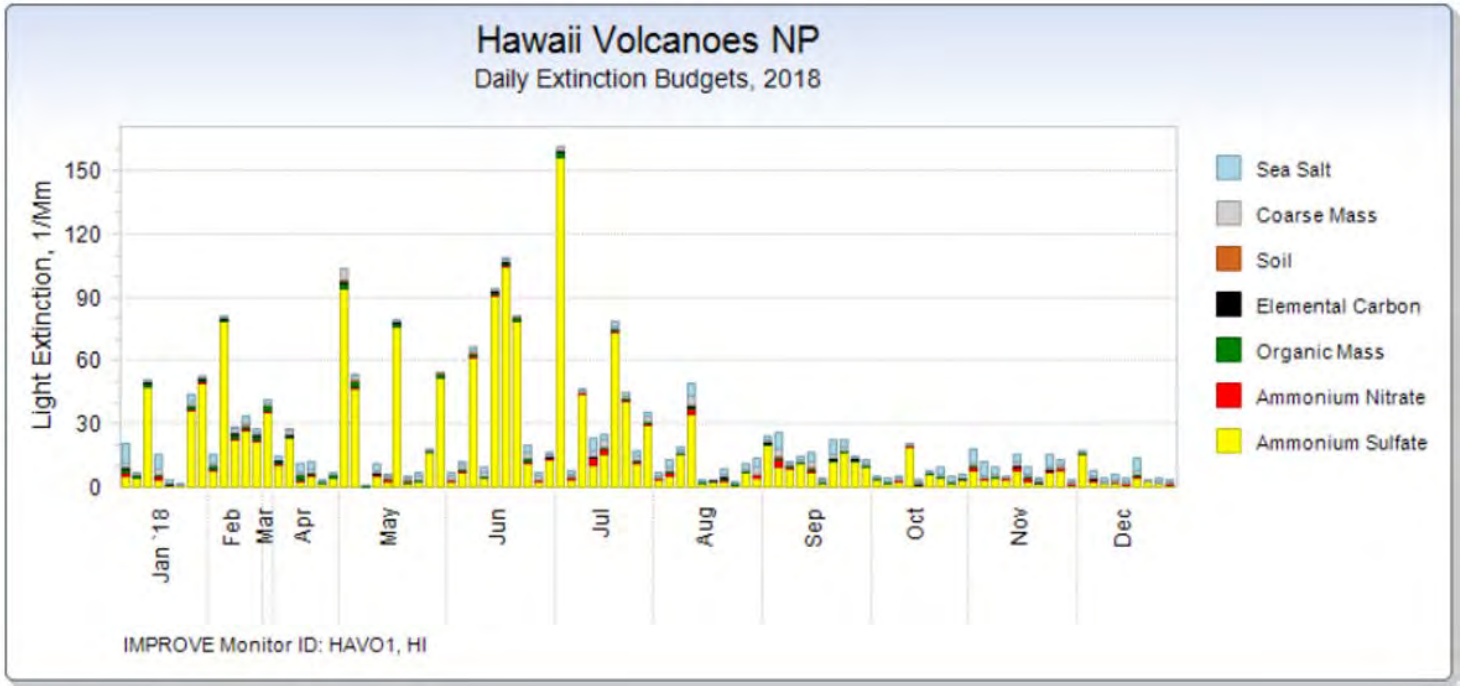
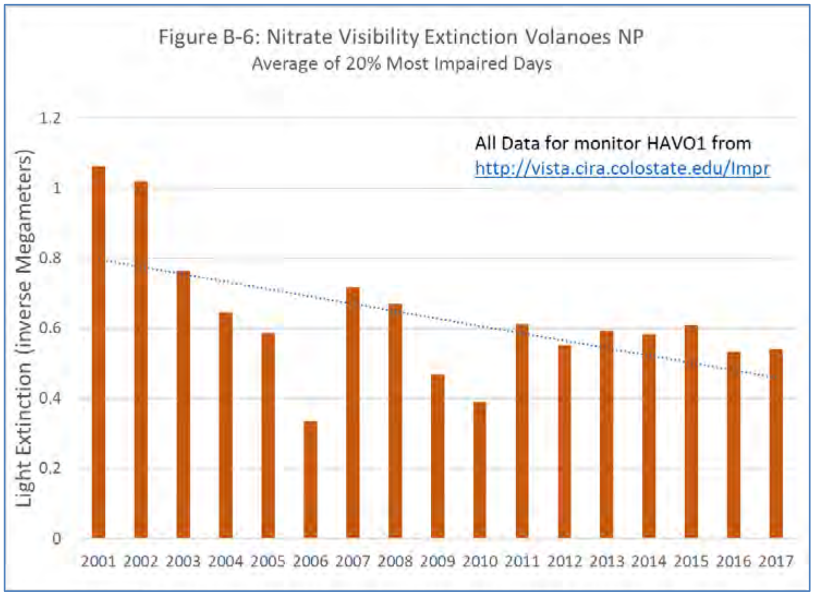


Figure B-5: Time Series of 2018 Daily Haze Extinction Composition Plots for the Hawaiʻi Volcanoes IMPROVE Site



The nitrate contribution to visibility impairment in the above bar charts is shown as a narrow "red" segment. The small size relative to other constituents clearly shows that nitrate is only a small contributor. Additionally, the Figures B-6 and B-7 below which presents only the ammonium nitrate visibility impairment also shows that nitrates, already small contribution, is trending downward.



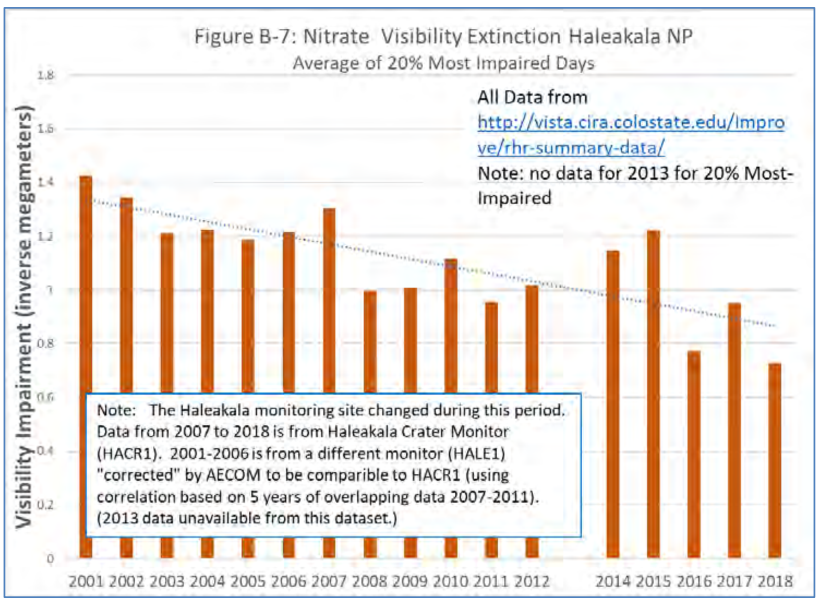
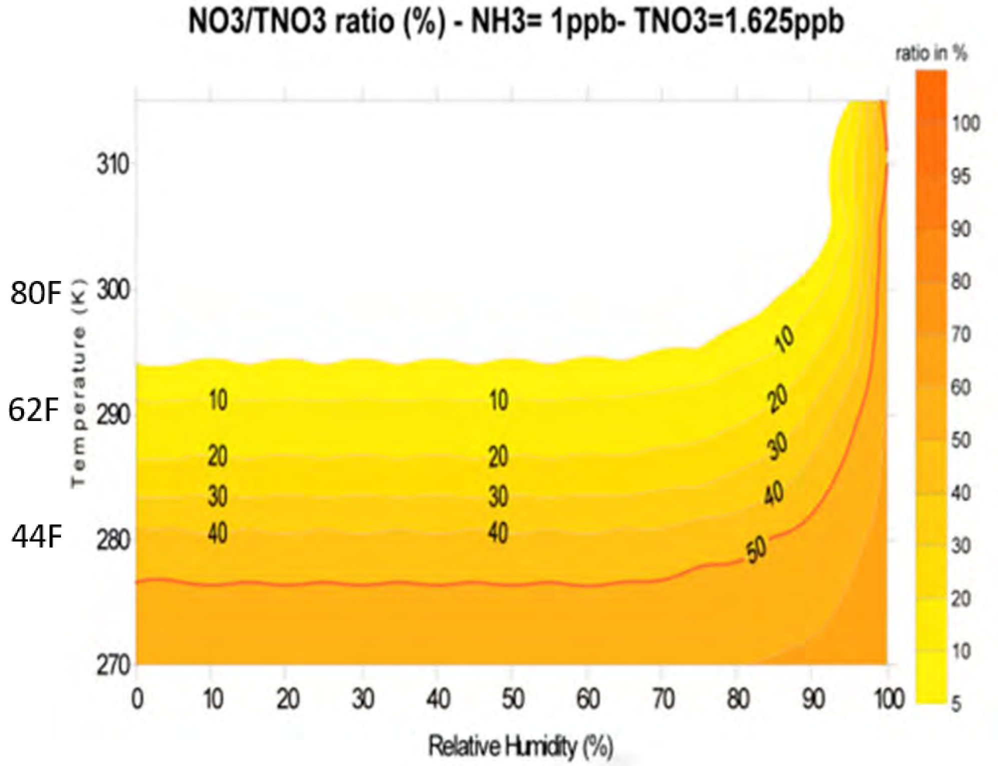


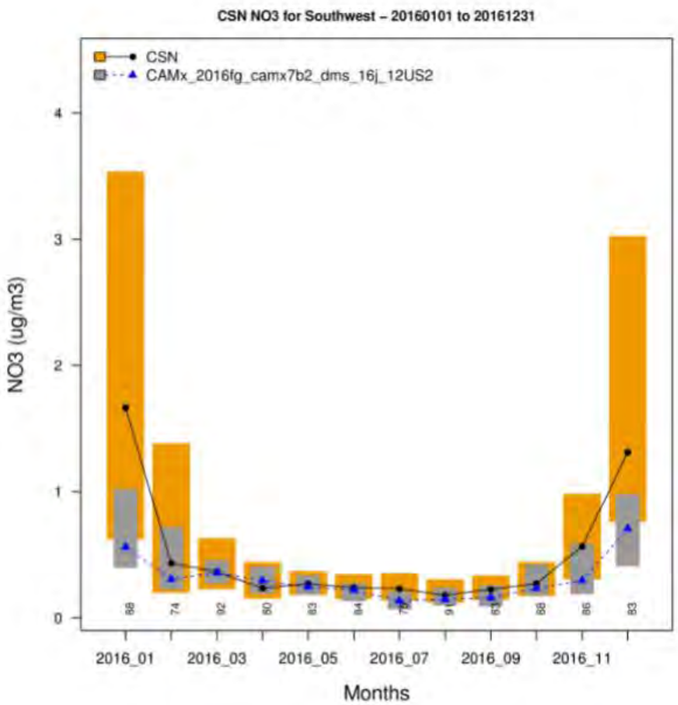
Figure B-8: CALPUFF Example Plot of Aerosol Percentage of Total NOx Equilibrium

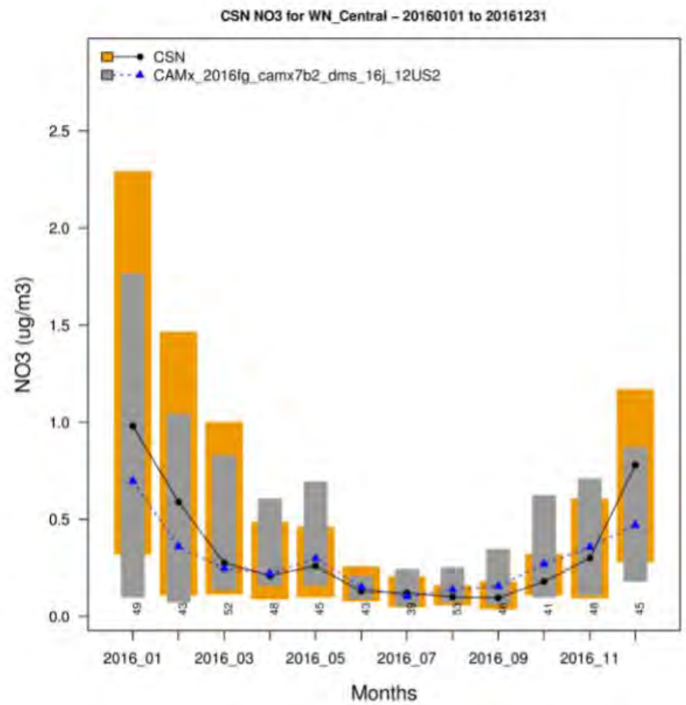


The potential for the formation of haze due to NOx emissions is very low in Hawaiʻi because of the warm weather conditions year-round. This strong dependency of the equilibrium relationship between invisible gaseous HNO_3 and visible NO_3 haze particles as a function of ambient temperature is illustrated in Figure B-8. In Figure B-8, it is evident that for most conditions, the percentage of total nitrate in the form of particulate (NO_3) is less than 20% for temperatures above approximately 286 degrees Kelvin (approximately 55 degrees Fahrenheit). Temperatures at most locations in Hawaiʻi rarely get that low and are not that low at any of the Hawaiian Electric plant locations.

This dependency of nitrate haze formation as a function of temperature (and season) for more seasonally-varying locations in the United States is shown in the September 2019 EPA modeling report[2] in Figure B-9 (from Appendix A of that report). This figure shows that the thermodynamics of the nitrate haze equilibrium result in much greater particulate formation in winter versus other seasons for more temperate climates, while NOx emissions are expected to be relatively constant over the entire year. This implies that NOx emission reductions would only be effective for haze reduction during cold winter months, while consideration of NOx emission reductions in other months is relatively ineffective.

Figure B-9: Monthly Variation of Nitrate Particulate Concentrations for Selected IMPROVE Sites from EPA 2019 Modeling Report





additional pollution controls at Hawaiian Electric facilities for Regional Haze progress should be limited to SO_2 for sources on Hawaiʻi Island.

6. Natural Sources of SO_2 From Volcanic Activity

Volcanic activity on the Hawaiʻi Island represents a unique and challenging complication to understating haze in Hawaiʻi Class I areas. The Kilauea volcano on Hawaiʻi Island has been active for several years, and the levels of SO_2 emissions are being monitored by the United States Geological Survey. As shown in Figure B-11[12] (related to the SO_2 National Ambient Air Quality Standards implementation and monitoring), there were over 2 million tons of SO_2 emissions from volcanic activity on Hawaiʻi Island in the year 2014, compared to roughly 2,000 tons of power plant SO_2 emissions for that year. As noted in a *Frontiers in Earth Science* 2018 article[13], the volcanic SO_2 emissions have been relatively steady at levels close to 2 million TPY for the period of 2014 to 2017.

The extremely high levels of natural SO_2 emissions present a significant challenge for defining "impaired" haze days because the same pollutant (i.e., SO_2) is emitted by volcanic activity and the power plants and other combustion sources. Therefore, the RHR glidepath for the two Class I areas in Hawaiʻi is difficult to establish if naturally-caused haze is to be excluded from the analysis.

There appears to be very little anthropogenic haze impairment remaining at Haleakalā National Park because there are very few sources on Maui upwind of the park and there are no land masses upwind of Maui for thousands of kilometers. For Hawaiʻi Island, the natural sources of SO_2 are part of (or adjacent to) the park, so they are likely to be a large and continuous source of naturally-caused haze.

Even the anthropogenic sources (from power plants) are projected to be phased out well before the end point of the RHR (i.e., 2064) by Hawaiʻi's State Renewable Portfolio Standards Law ("RPS") implementing requirements to convert 100% of the state's electrical generation to renewable energy sources. This RPS law (Hawaiʻi Revised Statute §269-92) will substantially reduce emissions of haze precursors by 2045. Further details of the past and future benefits of the RPS requirements are detailed in separate Appendix C.

[12] https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.
[13] Elias, T., C. Kern, K. Horton, A. Sutton, and H. Garbeil, 2018. Measuring SO_2 Emission Rates at Kīlauea Volcano, Hawaiʻi, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci*. 6:214. doi: 10.3389/feart.2018.00214. https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full.

Figure B-10: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

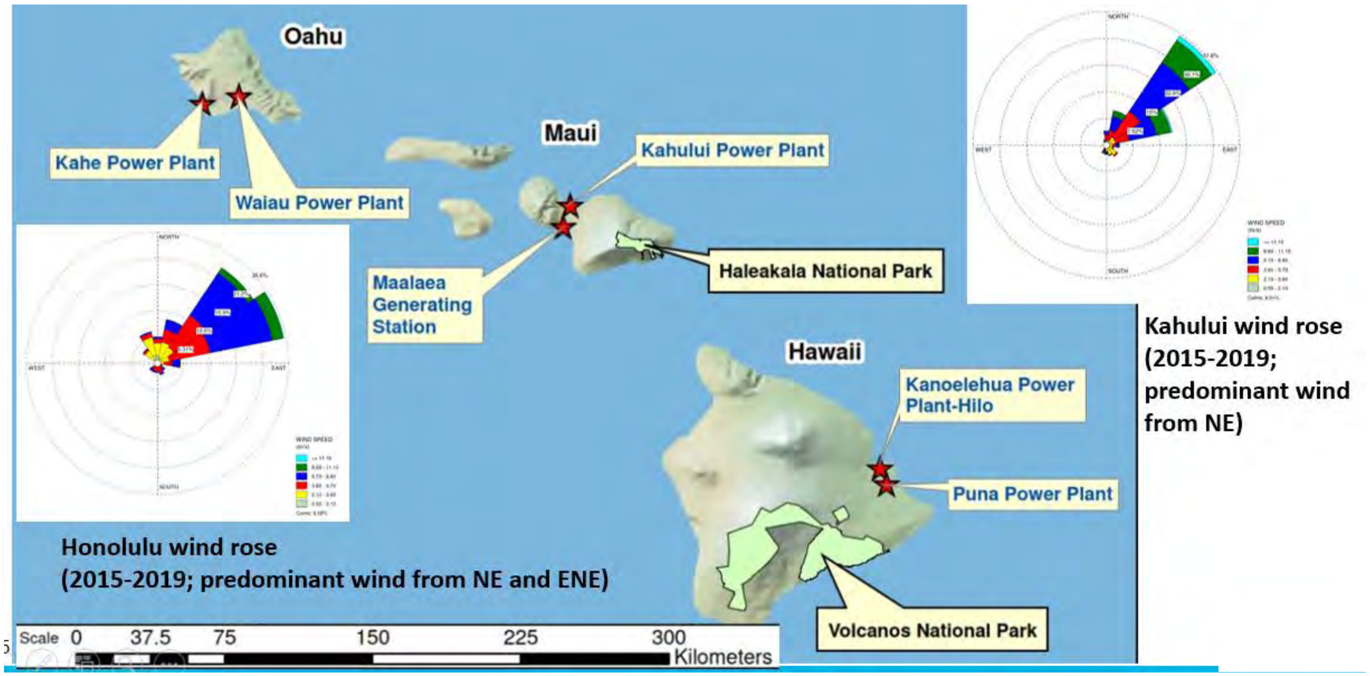
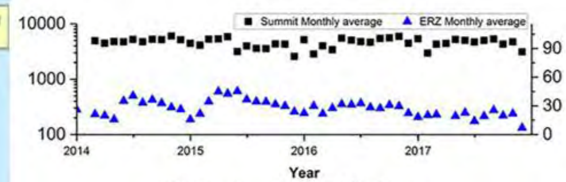


Figure B-11: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

2017 SO_2 Emissions (from NEI)

site name	TPY SO2
HELCO - Keahole Power Plant	81.94
HELCO - Waimea Power Plant	0.00
HELCO - Kanoelehua Power Plant/ HILL	2167.18
HELCO - Puna Power Plant	186.84

2014-2017 Volcano SO_2 Emissions average about 1.86 Million TPY



ERZ = Eastern Rift Zone

7. Conclusions

The state of Hawaiʻi is isolated from all other states and has very unique regional haze issues due, in part, to its tropical climate, the prevalent trade winds, very large natural emissions of haze precursors, and statewide commitment to renewable energy.

- Emission sources on Oahu and Maui are downwind of Hawaiʻi's Class I areas and do not contribute to haze issues, such that additional emission controls would not contribute to further reasonable progress at either of Hawaiʻi's Class I area National Parks. This is consistent with the EPA's First Decadal Review findings.

- Additionally, NOx emissions do not significantly contribute to haze in Hawaiʻi due the nitrate chemistry and Hawaiʻi's warm climate, and additional NOx controls would likewise not contribute to further reasonable progress. Therefore, NOx should not be regulated as a contributing precursor to haze in Hawaiʻi; especially from Oahu and Maui sources that are downwind of the parks. If they are reviewed as precursors, consideration should be given to their insignificant contribution when evaluating possible controls.

- Direct PM emissions constitute a very small portion of the haze associated with the worst 20% haze days in the Hawaiʻi Class I areas. Furthermore, significant portions of the observed haze in the categories of elemental carbon, soil, and coarse mass are due to volcanic emissions. Therefore, further PM controls on power plant sources would not have a significant benefit for visibility at these Class I areas.

- For the above reasons, the only pollutant that should be considered for possible haze controls in the state of Hawaiʻi is SO_2 which is consistent with the findings of the First Decadal Review. Furthermore, the only Hawaiian Electric sources to be considered for a four factor analysis for SO_2 should be those that are predominantly upwind of a Class I area which include only the Puna and Kanoelehua-Hill Generating Stations on Hawaiʻi Island.

- Hawaiʻi's Class I area haze impacts are principally due to natural sources. Volcanic emissions of precursor SO_2 during the 2014-2017 period of analysis were three orders of magnitude greater than the anthropogenic emissions on Hawaiʻi Island. Volcanic NOx emissions were about three times greater than all the state's NOx emissions. Since these natural emissions are the principal cause of haze at the two Class I areas in the state and are difficult to distinguish from the relatively small amount of anthropogenically-caused haze, photochemical grid modeling is not practical or even needed. The definition of "impaired days" for Hawaiʻi Volcanoes National Park as referenced in some of the figures in this report is uncertain due to the overwhelming influence of natural emissions of SO_2.

- For Haleakalā National Park, with the lack of upwind anthropogenic sources, it could be reasonably concluded that natural conditions are already attained, and no further Reasonable Progress modeling (or controls) is needed. For Hawaiʻi Volcanoes National Park, the only United

States anthropogenic potential sources are those upwind of the park on Hawai‘i Island; all other sources in the state are not contributing to haze at the Class I areas.

- Implementation of Hawai‘i’s RPS (discussed in detail in Appendix C) will provide a dramatic reduction of virtually all power plant haze-causing emissions in the state of Hawai‘i well before the year 2064. This Hawai‘i state law established enforceable requirements that a certain the percentage of electricity must be generated from renewable energy sources by the end of identified benchmark years leading to 100% renewable energy by 2045. The interim targets are 30 percent by 2020, 40 percent by 2030, and 70 percent by 2040 which provide an RPS “glide path” for EGUs that mirrors the RHR visibility improvement glide path for the next few decades. No separate new regional haze measures for EGUs are needed to assure reasonable progress for this decadal period.

Plans for renewable energy sources, the likely reduction in utilization of fossil-fueled electric generation in this interim period, the unique climate and wind patterns, and the difficulty of addressing the high volcanic emissions should be considered in the current planning for the Second Decadal Review process for the state of Hawai‘i.

Appendix C:
Hawai‘i’s Renewable Portfolio Standards (“RPS”) Contribution to Regional Haze Progress

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March 30, 020

Hawaiʻi's Renewable Portfolio Standards ("RPS")
Contribution to Regional Haze Progress

1. Executive Summary

Hawaiʻi's ongoing conversion of fossil-fueled electric generation to renewable energy sources as mandated by the Hawaiʻi Revised Statute ("HRS") §269-92 Renewable Portfolio Standards ("RPS") is significantly decreasing emissions from Hawaiʻi's electric generating stations. Past actual and expected future decreases in usage of fossil-fueled electric generating units ("EGUs") are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the Regional Haze Rule ("RHR"). Emissions from the majority of Hawaiʻi's electric generating plants are not a significant contributor to haze at Class I areas (for reasons explained in Appendix B). Further, their very low impact is being mitigated under the RPS state law. This rate of progress from the RPS law can be relied upon for further emissions reductions from EGUs in the coming years and thus separate further requirements for EGU controls under the RHR are not needed at this time. The following sections of this appendix provide a background on the RPS requirements and progress to date, and high confidence of continued progress consistent with the goals of the RHR.

2. Renewable Portfolio Standards

In 2002 the Hawaiʻi RPS legislation set voluntary goals for converting the islands' electrical generation from fossil fuels to renewable energy. In 2005, the RPS was set into law as binding requirements for Hawaiʻi electric utility companies. The law requires that electric utilities in Hawaiʻi achieve 100% of their electric generation from renewable energy sources by 2045 and meet a series of interim limits for the percentages of their electricity sales that must be provided by renewables (e.g., 30% renewable by 2020, and 40% by 2030, etc.). Renewable energy sources such as solar, hydro and wind energy have no direct emissions. Others such as biomass combustion have significantly lower emissions (especially sulfur dioxide ("SO_2")) than fossil fuels. Consequently, the RPS law results in steady progress in emissions reductions from electric utilities creating, in effect, an "RPS glidepath" providing dramatic reduction of electric generating unit emissions by mid-century.

The RPS program, although not directly related to the Regional Haze Rule ,is providing emissions reductions and improvements to air quality consistent with the goals of the RHR.

Table C-1 shows the interim and final RPS for EGUs along with the Regional Haze adjusted glidepath emissions reductions goals[1].

[1] Regional Haze Adjusted Glidepath assumes consistent reductions in haze precursor emissions impacts from all U.S. anthropogenic sources from the baseline average of 2000-2004 to zero impacts in 2064, i.e. natural background.

Table C-1 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement
2010	10%	8%
2015	15%	17%
2020	30%	25%
2030	40%	42%
2040	70%	58%
2045	100%	67%
2065		100%

This table illustrates that the emissions reductions from EGUs under the RPS are similar to the visibility goals of the Regional Haze Program in the intermediate years and become much more stringent in later years. The RPS seeks to achieve 100% renewable electrical supply by 2045, which is twenty years earlier than the RHR target of 2065 to achieve natural background visibility in Class I areas.

3. Historical RPS Achievement

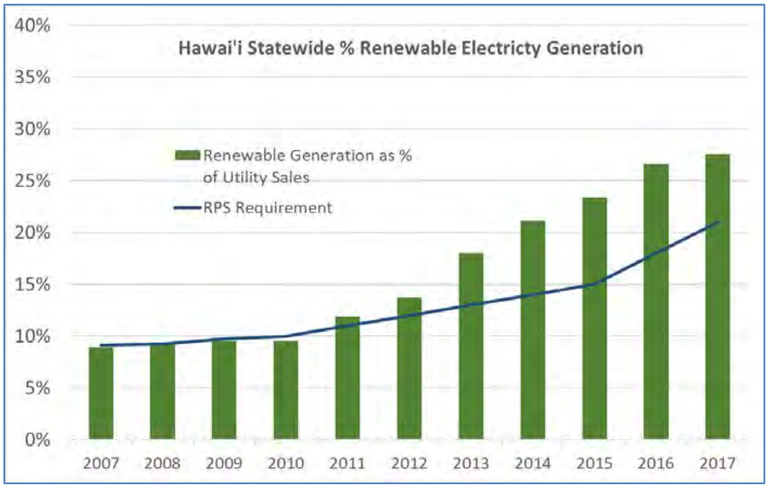
Hawaiian Electric[2], and other electric utility providers in Hawaiʻi, have made excellent progress in developing and supporting renewable energy sources. Figure C-1 below shows the percentage of all electrical sales statewide provided by renewable sources since the RPS inception (green columns).[3] It also shows as a line illustrating the RPS interim standards (with proportional progress assumed between RPS milestone years). This figure illustrates that Hawaiʻi EGUs have made significant progress to date and have been ahead of the RPS interim targets.

Hawaiian Electric represents majority of Hawaiʻi's electric generation. Figure C-2 shows the renewable energy source percentages for this same period specifically for Hawaiian Electric. The data follows the same trend as the statewide figures and this figure also shows a breakdown of the type of renewable energy technology used.

[2] "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawaiʻi Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawaiʻi Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

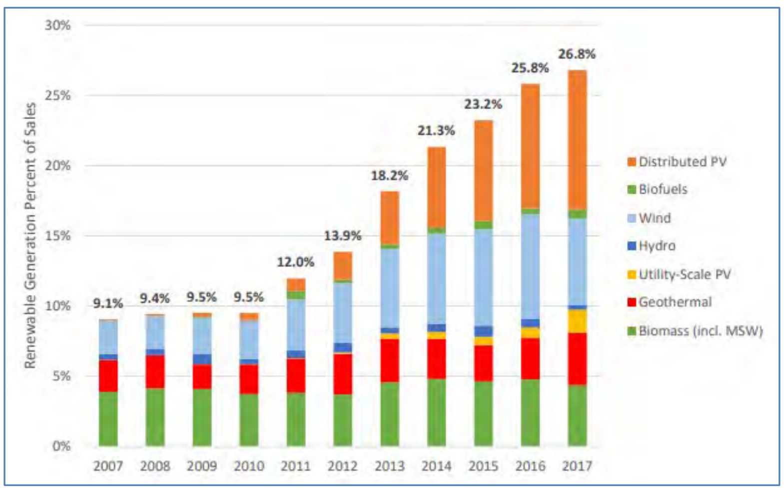
[3] *Hawaiʻi Public Utility Commission* (PUC), *"Report to the 2019 Legislature on Hawaiʻi's Renewable Portfolio Standards", Dec. 2018* https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

Figure C-1 Statewide Renewable Portfolio Progress



Source: https://puc.Hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf

Figure C-2 Hawaiian Electric Companies RPS Achievement by Generation Technology[4]



[4] PUC Dec. 2018 Report, Figure 2, page 7.

4. Future RPS Achievability

To date, Hawaiʻi's electric utilities have generally met or exceeded the RPS requirements. Continued progress consistent with RPS is expected to continue. Projects and plans are already in place to continue this rapid RPS shift to renewable energy sources for the period of interest of the next decadal period of the RHR. In its December 2018 report to the state legislature, the Hawaiʻi Public Utility Commission ("PUC") indicated that *"future renewable projects under construction or planned for the HECO Companies and KIUC should ensure that the state remains on track for meeting the 2020 and 2030 RPS targets."*[5]

Figure C-3 below shows Hawaiian Electric's projection of percent renewables through 2030 presented in the December 2018 PUC report. This projected progress remains well ahead of the RPS requirements which also is ahead of the requirements of the Regional Haze glidepath goals.

Figure C-3 Hawaiian Electric Companies RPS Expectation by 2030 Technology[6]

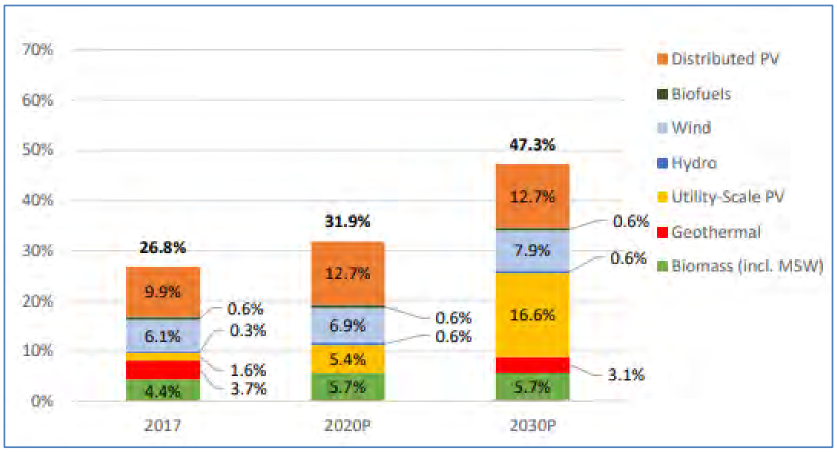


Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC's 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric's renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian Electric has an internal target to achieve 100% renewables by 2040, five years ahead of the RPS requirement and 25 years ahead of the RHR goals.

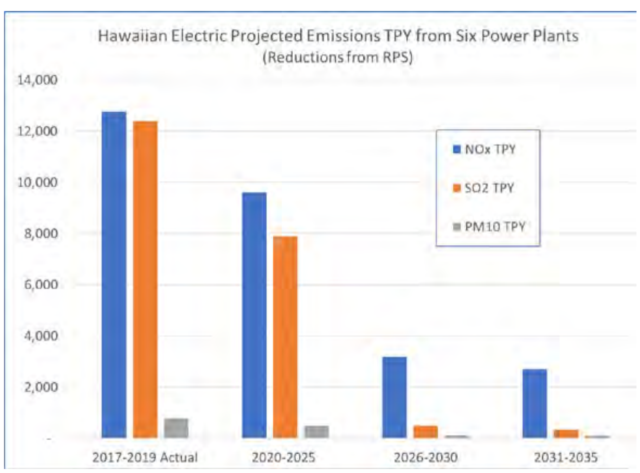
[5] PUC Dec. 2018 Report, page 2.
[6] PUC Dec. 2018 Report, Figure 2, page 16.

Table C-2 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement	Hawaiian Electric % Renewables
2010	10%	8%	9.5% (actual)
2015	15%	17%	23.2% (actual)
2020	30%	25%	31.9% (projection)
2030	40%	42%	47.3% (projection)
2040	70%	58%	100% (goal)
2045	100%	67%	100% (goal)

Hawaiian Electric's latest projections show an even more rapid shift to renewable energy sources than forecasted in 2018. This will continue to decrease Hawaiian Electric facility emissions. For example, Figure C-4 illustrates Hawaiian Electric's latest forecast emissions trends for total nitrogen oxides ("NOx"), sulfur dioxide ("SO_2") and Particulate Matter ("PM_{10}") emissions (in tons per year "TPY") from the six power plants (Waiau and Kahe Generating Stations on Oahu, Kahului and Maalaea on Maui, and Kanoelehua-Hill and Puna on Hawai'i) requested to conduct Four-Factor Analyses by the Hawai'i Department of Health ("DOH"). These dramatic emissions decreases illustrate the expected progress from RPS alone – without any additional RHR measures The forecast emissions shown in Figure C-4 was derived from recent fuel consumption projections based on the resource plans and planning assumptions submitted to the PUC as part of Hawaiian Electric's 2016 Power Supply Improvement Plan ("PSIP") which was accepted by the PUC and recent renewable project applications.

Figure C-4 Hawaiian Electric NOx Forecast Emissions



The emissions reduction is quite rapid and most of the projected reduction by Hawaiian Electric are expected to be in place prior to 2028, the next Regional Haze planning milestone.

Although this projection is based on reasonable assumptions, plans are subject to change as there is some uncertainty regarding future projections and forecast assumptions. For this reason and due to energy security issues, Hawaiian Electric cannot commit to specific dates for particular emissions reductions or final retirements of any specific generating station. Nevertheless, Hawaiian Electric is on an aggressive path to end fossil-fueled generation and replace it with renewable energy sources – especially during this next decadal period. This progress should be sufficient for Hawaiian Electric's contribution to the state's efforts regarding reasonable progress of the RHR for the current Regional Haze decadal review.

5. Reliance on RPS for this Regional Haze Decadal Review

The RPS requirements are part of Hawaiʻi state law. An electric utility failing to meet the RPS requirements is subject to enforcement action and penalties by the PUC unless the PUC determines the electric utility is unable to meet the RPS due to factors beyond its reasonable control. However, given the progress to date of the Hawaiʻi electric utilities acquiring renewable generation and expectations for planned renewable projects in the near future, it is reasonable to expect that RPS will result in continued steady progress, at least through 2030.

The DOH can rely on the RPS for regional haze progress without having to impose separate RHR requirements in facility permits. This is supported by EPA guidance which states that "Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and verifiable basis for quantifying any change in future emissions due to operational changes may be another."[7]

Even if progress were slower than currently expected, it would not prevent the RPS from being relied upon as the major EGU contribution to meeting Hawaiʻi's regional haze goals. The time perspective of the Regional Haze Program is long. Making wise decisions that help achieve the long-term goals is important. Hawaiʻi electric utilities are currently focusing resources on advancing renewable energy projects that will permanently displace fossil-fueled unit generation and fossil-fueled combustion emissions. These ongoing RPS efforts help achieve the long-term goals of the RHR and provide permanent emissions reductions and other societal benefits. In contrast, new investments in conventional emissions controls on aging fossil-fueled units provide only modest short-term benefits impose additional costs on rate payers and will have no lasting value when those units are deactivated or retired.

[7] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period – August 2019 at page 17. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Comments on Four – Factor Analysis

DAVID Y. IGE
GOVERNOR OF HAWAII

BRUCE S. ANDERSON, Ph.D.
DIRECTOR OF HEALTH

STATE OF HAWAII
DEPARTMENT OF HEALTH
P.O. Box 3378
HONOLULU, HAWAII 96801-3378

In reply, please refer to:
File:
20-317E CAB
File No. 0240

July 8, 2020

Ms. Karen Kimura
Director, Environmental Division
Hawaiian Electric
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Dear Ms. Kimura:

Subject: Four-Factor Analysis for Regional Haze
Covered Source Permit No. 0240-01-C
Hawaii Electric Company, Inc. (HECO)
Kahe Generating Station
Located At: 92-200 Farrington Highway, Waianae, Oahu

The Department of Health, Clean Air Branch (CAB) acknowledges receipt of the subject four-factor analysis on April 6, 2020 and has determined the analysis to be incomplete. Please refer to the attached comments for completing the four-factor analysis. Pursuant to 40 Code of Federal Regulations (CFR) §51.308 (d)(1) of the Regional Haze Rule (RHR), the four-factor analysis will be used to establish control measures and reasonable progress goals for Hawaii's Regional Haze State Implementation Plan (RH-SIP).

The CAB requests that you address the comments and resubmit the subject four-factor analysis with the appropriate revisions by **August 10, 2020.**

If there are any questions regarding this matter, please contact Mr. Mike Madsen of my staff at (808) 586-4200.

Sincerely,

Marianne Rossio

MARIANNE ROSSIO, P.E.
Manager, Clean Air Branch

MM:rkb

Attachment

c: Debra Miller, National Park Service, Air Resources Division
Don Shepherd, National Park Service, Air Resources Division
Melanie Peters, National Park Service, NPS-Air

Attachment I

After our review and feedback from the National Park Service (NPS) and Environmental Protection Agency (EPA), Region 9, we have the following comments on the four-factor analysis for Boilers K-1 through K-6:

a. The cost per ton of sulfur dioxide (SO_2) removed was provided for switching fuel from residual low sulfur fuel oil No. 6 to ultralow sulfur diesel (ULSD); however, there was no cost analysis provided for nitrogen oxide NO_X or particulate matter less than ten (10) microns in diameter (PM_{10}). Please provide the cost per ton of NO_X and PM_{10} reduced for switching from residual low sulfur fuel oil No. 6 to ULSD. Also, provide the cost per total combined tons of SO_2, NO_x, and PM_{10} reduced for the fuel switch.

b. Section 3.2.2 of the analysis states that fuel switching could be implemented within two (2) to three (3) years. Other facilities have reported that a fuel switch could be accomplished within as short as one (1) year. The amount of time specified for switching fuels at the Kahe Generating Station seems excessive. Please explain the reason for the long compliance time and whether there are ways to reduce the time for implementing this control measure.

c. Section 3.2.3 states that fuel switching to a lower sulfur fuel will increase the cost of electricity. Although the topic was discussed in the technical support document for the Regional Haze Federal Implementation Plan, it is not something we can generally take into consideration for the regional haze four-factor analysis in this second planning period.

d. Provide documentation of the internal engineering study in 2012 identifying a circulating dry scrubber (CDS) as the best option for controlling SO_2 emissions from the boilers.

e. Section 3.2.4 states that the remaining useful life of the boilers do not impact the annualized cost of controls because the useful lives of the boilers are assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. This section of the analysis also indicates that, in HECO's Power Supply Improvement Plan (PSIP), HECO intends to retire Kahe Boilers 5 and 6 in 2028, Kahe Boilers 1 and 2 in 2035, and Kahe Boilers 3 and 4 in 2039. Please note that the PSIP is not federally enforceable. In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, EPA guidance for the second planning period allows the use of the enforceable shutdown date as the end of the remaining useful life. This measure would need to be included in the RH-SIP and/or be federally enforceable. Please see 40 CFR 51.308(f)(2). If HECO agrees to make a commitment to the shutdowns through federally enforceable permit limits, the remaining useful life assumed for the control measure is acceptable. The federally enforceable shutdowns could also be used as control measures for showing reasonable progress if the shutdowns occur in the second regional haze planning period (2018-2028). In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be the full period of the useful life of that control as recommended by EPA's Control Cost Manual (CCM). The current (2019) CCM specifies a remaining useful life for SCR of thirty (30) years at power plants and twenty (20) years for other sources.

f. The current prime interest rate (currently at 3.25%) should be used to estimate the costs of additional emission controls, rather than seven percent seven (7%) used in the analysis. Please see the following site for the current bank prime rate: https://www.federalreserve.gov/releases/h15/. The prime interest rate has not been seven percent (7%) or higher in the past twelve (12) years. A three (3%) interest rate may also be considered.

g. Fuel costs are provided in 2019 dollars and the control costs are in 2018 dollars. Please provide control costs in 2019 dollars.

h. Flue gas recirculation (FGR) is listed as a technically feasible control option; however, the cost effectiveness of FGR was not evaluated. Please evaluate the cost effectiveness of FGR for reducing NO_X emissions from the boilers and provide the results in Table 4-3.

i. Please add the combination of FGR plus low NO_X burner (LNB) and overfire air (OFA) to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

j. Selective non-catalytic reduction (SNCR) is listed as a technically feasible control option; however, the cost effectiveness of SNCR was not evaluated. Please evaluate the cost effectiveness of SNCR for reducing NO_X emissions from the boilers and provide the results in Table 4-3.

k. Please add the combination of SNCR plus LNB and OFA to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

l. Please add the combination of selective catalytic reduction (SCR) plus LNB and OFA to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

m. The NO_X output rate of 0.1 pound per million British thermal unit (lb/MMBtu) was assumed for SCR. It is generally assumed that new SCR can achieve 0.05 lb/MMBtu (or lower) on an annual basis. The current (2019) CCM states that a 0.05 lb/MMBtu outlet NO_X rate based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.

n. In the control cost worksheets, a retrofit factor of 1.5 was selected from a recommended range between 0.8 and 1.5 for retrofitting the boilers with SCR. Please note that the CCM for SCR allows a retrofit factor of greater than one (1) provided the reasons for using the higher retrofit factor are appropriate and fully documented. A note in the control cost spreadsheet indicated that a retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location. For selecting a retrofit factor of greater than one (1), please provide additional detail on the complexities involved for retrofitting the boilers with SCR at the Kahe Generating Station.

o. Appendix B of the four-factor analysis indicated that, in the recent past, Hawaii's volcanic SO_2 emissions are about 1,000 times greater than anthropogenic SO_2 emissions and volcanic activity in Hawaii produced as much as two (2) million tons of SO_2 per year. Please note that SO_2 emissions have significantly decreased after the Kilauea eruption ended in September 2018. The United States Geological Survey (USGS) stated, that in 2019, the summit is the only source releasing enough SO_2 emissions to be quantified using ultra-violet spectroscopy. Preliminary USGS results for 2019 indicate an average summit daily SO_2 emission rate of about 43 tons and an annual total SO_2 emission rate of about 17,119 tons which is far lower than the two (2) million tons of SO_2 reported to be emitted by the volcano in Appendix B. Note that the total combined SO_2 emissions from point sources screened for four-factor analyses were about 18,058 tons per year in 2017 which is 939 tons higher than preliminary USGS estimates of volcanic SO_2 for 2019. Since Kilauea eruption activity ended in September 2018, point sources screened for four-factor analysis now play a more significant part in SO_2 visibility impacts.

p. Appendix B of the four-factor analysis also noted that volcanic activity on Hawaii Island is the largest source of NO_x in the state based on a NO_x emission estimate for the Kilauea Volcano of roughly 125,000 tons per year. Data, indicating worldwide volcano NO_x and SO_2 emissions of 1.5 and 23 teragrams, respectively, was used for the estimate. It was stated that the NO_x was likely caused by thermal contact of air with lava. Based on the NO_X/SO_2 ratio using the worldwide numbers, it was then assumed that NO_X emissions from Kilauea Volcano are about 6% of the volcano's total SO_2 emissions. It was also assumed that Hawaii volcanic activity emits approximately two (2) million tons per year of SO_2. Please note that he global ratio of NO_x/SO_2 is likely not appropriate to use for estimating NO_x emissions from the Kilauea Volcano. Interagency Monitoring of Protected Visual Environments data shows that annual light extinction from ammonium nitrates for the most impaired days at Haleakala National Park over the current visibility period (2014-2018 when the volcano was erupting) are higher than those at Hawaii Volcanoes National park where the volcano is located. Also, while volcanic SO_2 emissions were reported to be as high as two (2) million tons per year when the Kilauea Volcano was erupting, SO_2 emissions have significantly decreased after the Kilauea eruption ended in September 2018. There currently is no lava in the Kilauea summit crater. Instead, a lake of water has formed in the Kilauea crater after the volcano stopped erupting towards the end of 2018. Please refer to: https://earthobservatory.nasa.gov/images/146687/a-new-lakewater-not-lavaon-kilauea.

q. In the four-factor analysis, HECO states that no reduction measures in addition to Hawaii's Renewable Portfolio Standards (RPS) are proposed to meet the RHR requirements. While provisions mandated by the RPS are subject to enforcement action by the Hawaii Public Utilities Commission, these are state only enforceable requirements which are not federally enforceable under the federal Clean Air Act. The RHR requires federally enforceable emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional Haze. As an option, HECO may propose caps for the emissions of visibility impairing pollutants (SO_2, NO_X, and PM_{10}) based on anticipated emission reductions from the RPS as a reasonable progress measure that could be incorporated into permits. These emission caps would need to occur in the second planning period (2018-2028) in order to be credited as a control measure for reasonable progress. Additional measures for showing reasonable progress include federally enforceable plant shutdowns as described in comment e above. In essence, HECO could propose: 1) federally enforceable conditions for retiring units during the second implementation planning period (2018-2028) and include those units and retirement dates in the four factor analyses along with a four factor analysis of the remaining equipment; 2) propose federally enforceable emission control measures such as fuel switching or add-on controls with the associated pollutant reductions, or 3) propose federally enforceable permit limits such as emission caps, for operational flexibility, or hour restrictions with the associated compliance dates or any combination of 1, 2, or 3 above.

Responses to Comments

Attachment 1
Responses to the DOH's July 8, 2020 Comments
Regional Haze Four-Factor Analysis, Dated April 6, 2020
Kahe Generating Station
Hawaiian Electric Company, Inc.

a. The cost per ton of sulfur dioxide (SO_2) removed was provided for switching fuel from residual low sulfur fuel oil No. 6 to ultralow sulfur diesel (ULSD); however, there was no cost analysis provided for nitrogen oxide (NO_X) or particulate matter less than ten (10) microns in diameter (PM_{10}). Please provide the cost per ton of NO_X and PM_{10} reduced for switching from residual low sulfur fuel oil No. 6 to ULSD. Also, provide the cost per total combined tons of SO_2, NO_X, and PM_{10} reduced for the fuel switch.

   Response – The requested costs will be provided within the updated four-factor analysis report.

b. Section 3.2.2 of the analysis states that fuel switching could be implemented within two (2) to three (3) years. Other facilities have reported that a fuel switch could be accomplished within as short as one (1) year. The amount of time specified for switching fuels at the Kahe Generating Station seems excessive. Please explain the reason for the long compliance time and whether there are ways to reduce the time for implementing this control measure.

   Response - Two to three years is a realistic estimate of the timeframe for fuel switching because of several factors: 1) Hawaiian Electric generally requests that the State of Hawaiʻi Public Utilities Commission (Commission) approve fuel contracts and issue its Decision and Order within one year following the filing of the application to the Commission; 2) Hawaiian Electric needs to go through a formal process to request bids from fuel suppliers; 3) Negotiations with the fuel supplier can take up to four months; 4) The schedule for any required infrastructure modifications are dependent on the extent on the required changes; 5) If fuel switching is required at other Hawaiian Electric facilities, the type of fuel to be switched and used, the effect on the fuel supply, and ability of the local refinery to accommodate the change may significantly be impacted; and 6) Imported fuel may be required if there is a lack of local supply.

c. Section 3.2.3 states that fuel switching to a lower sulfur fuel will increase the cost of electricity. Although the topic was discussed in the technical support document for the Regional Haze Federal Implementation Plan, it is not something we can generally take into consideration for the regional haze four-factor analysis in this second planning period.

   Response – Fuel costs are directly reflected in customer electricity rates on all islands Hawaiian Electric provides electricity; this is an important cost to the community that must be considered. Hawaiian Electric encourages the DOH to use the flexibility in the EPA's SIP guidance[1] in the selection of control measures necessary to make reasonable progress and to consider additional factors when developing the long-term strategy to improve visibility at Class I areas. Also, note that given the fragile condition of the state's fuel supply and because of Hawaiian Electric's position as a major customer in the market, a fuel supply change could have sweeping effects on the island's market that may not be apparent from the cost estimates associated with Hawaiian

[1] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

Electric such as the ability of the local refinery to accommodate the change and potential need for imported fuel.. Hawaiian Electric suggests that the DOH needs to take these factors into account in its decision-making process.

d. Provide documentation of the internal engineering study in 2012 identifying a circulating dry scrubber (CDS) as the best option for controlling SO_2 emissions from the boilers.

Response – Key excerpts from the July 10, 2012 Mercury and Air Toxics Standards (MATS)/National Ambient Air Quality Standards (NAAQS) Environmental Controls Study for Kahe Generating Station Units 1-6 prepared by Black & Veatch are included with this Response to Comments attachment as Attachment 5.

e. Section 3.2.4 states that the remaining useful life of the boilers do not impact the annualized cost of controls because the useful lives of the boilers are assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. This section of the analysis also indicates that, in HECO's Power Supply Improvement Plan (PSIP), HECO intends to retire Kahe Boilers 5 and 6 in 2028, Kahe Boilers 1 and 2 in 2035, and Kahe Boilers 3 and 4 in 2039. Please note that the PSIP is not federally enforceable. In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, EPA guidance for the second planning period allows the use of the enforceable shutdown date as the end of the remaining useful life. This measure would need to be included in the RH-SIP and/or be federally enforceable. Please see 40 CFR 51.308(f)(2). If HECO agrees to make a commitment to the shutdowns through federally enforceable permit limits, the remaining useful life assumed for the control measure is acceptable. The federally enforceable shutdowns could also be used as control measures for showing reasonable progress if the shutdowns occur in the second regional haze planning period (2018-2028). In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be the full period of the useful life of that control as recommended by EPA's Control Cost Manual (CCM). The current (2019) CCM specifies a remaining useful life for SCR of thirty (30) years at power plants and twenty (20) years for other sources.

Response - The capital recovery period will be increased to the CCM recommended value of 30-years for boiler controls (combustion controls, SCR, SO_2 post-combustion controls, and PM post-combustion controls). The capital cost recovery period updates will be included in the updated four-factor analysis report. Hawaiian Electric is still evaluating the retirement of its sources as part of the Regional Haze program, but due to the complexity of retirement factors Hawaiian Electric may provide additional information in the updated four-factor analysis report.

f. The current prime interest rate (currently at 3.25%) should be used to estimate the costs of additional emission controls, rather than seven percent seven (7%) used in the analysis. Please see the following site for the current bank prime rate: https://www.federalreserve.gov/releases/h15/. The prime interest rate has not been seven percent (7%) or higher in the past twelve (12) years. A three (3%) interest rate may also be considered.

Response – Hawaiian Electric will continue to use an interest rate of 7% because it is more appropriate than the prime interest rate for the four-factor analyses. The cost analyses follow the Office of Management and Budget (OMB) and EPA Air Pollution Cost Control Manual (CCM) guidance by using an interest rate of 7% for evaluating the cost of capital recovery. The EPA cost manual states that:

"*when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face.*" [2]

For these analyses, which evaluates equipment costs that may take place more than five (5) years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The CCM cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[3] However, the EPA CCM cautions the use of bank prime rates and states:

"*Analysts should use the bank prime rate with caution as these base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers.*" [4]

For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery. Actual borrowing costs experienced by firms are typically higher.

For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7%. OMB Circular A-4 states:

"*As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.*" [5]

The above statement is confirmed in the EPA CCM with the following statement:

"*When assessing the societal effect of regulations, such as for EPA rulemakings that are economically significant according to Executive Order 12866, analysts should use the 3% and 7% real discount rates as specified in the U.S. Office of Management and Budget (OMB) 's Circular A-4. The 3% discount rate represents the social discount rate when*

[2] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[3] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020. https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[4] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[5] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

consumption is displaced by regulation and the 7% rate represents the social discount rate when capital investment is displaced." [6]

g. Fuel costs are provided in 2019 dollars and the control costs are in 2018 dollars. Please provide control costs in 2019 dollars.

Response – The Chemical Engineering Plant Cost Index (CEPCI) for 2019 equals 607.5 which represents a 0.7% increase in cost from 2018. The control costs will be adjusted to 2019 dollars. The requested updates will be provided in the updated four-factor analysis report.

h. Flue gas recirculation (FGR) is listed as a technically feasible control option; however, the cost effectiveness of FGR was not evaluated. Please evaluate the cost effectiveness of FGR for reducing NO_X emissions from the boilers and provide the results in Table 4-3.

Response – The combustion controls in the four-factor analysis includes various air pollution reduction technologies and combinations of these technologies. FGR can be combined with LNB, if needed. The LNB with overfire air (OFA) costing provided in Appendix Table A-2 of the four-factor analysis was based on costing provided for LNB and LNB with OFA. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO_X control. Therefore, the costing provided in Appendix Table A-2 is applicable to range of various combustion controls and combinations of these controls.

For clarification, the provided costing for "LNB w/overfire" air will be renamed to "Combustion Controls" in the updated four-factor analysis report and the discussion in the four-factor analysis will also be updated accordingly.

i. Please add the combination of FGR plus low NO_X burner (LNB) and overfire air (OFA) to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

Response – See the response to item h.

j. Selective non-catalytic reduction (SNCR) is listed as a technically feasible control option; however, the cost effectiveness of SNCR was not evaluated. Please evaluate the cost effectiveness of SNCR for reducing NO_X emissions from the boilers and provide the results in Table 4-3.

Response – As stated in Section 4.1.2.2 of the four-factor analysis report, the estimated NO_X control range for SNCR for wall-fired boilers (K1, K2, and K5) is approximately 0.30-0.40 lb/MMBtu, <u>for a wall-fired boiler equipped with LNB (K6) the estimated control level is approximately 25%</u>[7], and for tangentially-fired boilers (K3 and K4) is approximately 0.20-0.25 lb/MMBtu. These estimated control ranges for uncontrolled boilers are in the same range as combustion controls.[8] SNCR is only effective in a relatively high and narrow temperature range and therefore, is not suitable for all applications. Several factors determine whether SNCR is an appropriate control for a source, including temperature, residence time, the feasibility of

[6] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, pp. 16-17. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[7] Cost Control Manual, Selective Noncatalytic Reduction, EPA, 2019.

[8] *Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler*, EPA, 1994.

installing reagent injection ports, and the NO_X concentration.[9] These site-specific operating and design characteristics of the emission unit must be evaluated on a case-by-case basis to determine whether SNCR is feasible. For these reasons, the effectiveness of SNCR will be based on the upper range of the estimated controlled emissions level.

EPA's SNCR costing spreadsheet was used to calculate the SNCR cost effectiveness for K1 and K5 (wall-fired boilers), K6 (wall-fired boiler with LNB), and K3 (tangentially-fired boiler). The SNCR cost effectiveness calculations for K1, K3, K5, and K6 are provided as representative costing for wall-fired and tangentially-fired boilers. Hawaiian Electric proposes to use this SNCR costing as a representative analysis for the boilers at the Kahe, Waiau, Kahului, Kanoelehua-Hill, and Puna Generating Stations instead of providing SNCR costing for each boiler. Due to the uncertainty in the level of control offered by SNCR, the upper control range was used (0.40 lb/MMBtu for wall-fired boilers (K1 and K5) and 0.25 lb/MMBtu for tangentially-fired boilers) was used in the cost effectiveness calculations. For K6 a control level of 25% (0.15 lb/MMBtu) was used in the cost effectiveness calculation.

The expanded cost effectiveness results for units K1, K3, K5, and K6 are provided in Attachment 3 included with this Response to Comments attachment. The cost effectiveness of SNCR added to uncontrolled boilers is greater than combustion controls and offers less control. SNCR has a lower cost effectiveness than SCR and SCR plus combustion controls. However, SNCR results in a lower level of control than SCR alone and SCR plus combustion controls. Based on the provided SNCR results, SNCR does not offer a significantly better control option than combustion controls, SCR, or SCR plus combustion controls.

The SNCR upper control range for Kahe units K1 and K2, wall-fired boilers, is 0.4 lb/MMBtu based on the evaluation performed for Kahe unit K1. The SNCR upper control range for Kahe units K3 and K4, tangentially-fired boilers, is 0.25 lb/MMBtu based on the evaluation performed for Kahe unit K3.

The SNCR costing spreadsheet and the cost effectiveness results are provided in Attachment 4 included with this Response to Comments attachment.

k. Please add the combination of SNCR plus LNB and OFA to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

Response – Due to the uncertainty in the level of control offered by SNCR, the combination of combustion controls and SNCR has the same level of expected control range as SNCR alone, approximately 0.20-0.40 lb/MMBtu for wall-fired boilers (K1,K2, and K5) and approximately 0.15-0.25 lb/MMBtu for tangentially-fired boilers (K3 and K4).[10] The SNCR plus combustion controls cost effectiveness calculations for Kahe K1 and K5, and K3 are provided as representative costing for wall-fired and tangentially-fired boilers, respectively. The cost effectiveness calculation is based on controlled emission levels of 0.20 lb/MMBtu for Kahe K1 and K5 (wall-fired boilers) and 0.15 lb/MMBtu for K3 (tangentially-fired boiler).

The expanded cost effectiveness results for K1, K3, K5, and K6 are provided in Attachment 3 included with this Response to Comments attachment and will be also be included in the updated four-factor analysis report. SNCR plus combustion controls has a lower cost effectiveness than SCR and SCR plus combustion controls. However, SNCR plus combustion

[9] Cost Control Manual, Selective Noncatalytic Reduction, EPA, 2019.
[10] *Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler*, EPA, 1994.

controls results in a lower level of control than SCR and SCR plus combustion controls. Based on the provided SNCR plus combustion controls results, SNCR plus combustion controls does not offer a significantly better control option than SCR or SCR plus combustion controls. Hawaiian Electric proposes to use this SNCR plus combustion controls costing as a representative analysis for the boilers at the Kahe, Waiau, Kahului, Kanoelehua-Hill, and Puna Generating Stations instead of providing SNCR costing for each boiler.

l. Please add the combination of selective catalytic reduction (SCR) plus LNB and OFA to Table 4.2, evaluate the cost effectiveness of this combined NO_X control measure for the boilers, and provide the results in Table 4-3.

   Response – The combination of SCR plus combustion controls is expected to reduce NO_X emissions to 0.05 lb/MMBtu and will be added to Table 4-2 in the updated four-factor analysis report. The cost effectiveness of SCR plus combustion controls will also be added to Table 4-3 in the updated four-factor analysis report.

m. The NO_X output rate of 0.1 pound per million British thermal unit (lb/MMBtu) was assumed for SCR. It is generally assumed that new SCR can achieve 0.05 lb/MMBtu (or lower) on an annual basis. The current (2019) CCM states that a 0.05 lb/MMBtu outlet NO_X rate based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.

   Response – The 0.05 lb/MMBtu referenced in the CCM generally applies to boilers equipped with combustion controls. As stated in the above response, the combination of SCR plus combustion controls is expected to reduce NO_X emissions to 0.05 lb/MMBtu. Several factors contribute to the level of control that SCR can provide. For these reasons, the level of SCR control for K1 – K5 was set to 0.1lb/MMBtu. Since K6 is equipped with combustion controls, the level of SCR control was reduced to 0.05 lb/MMBtu. The requested updates will be provided in the updated four-factor analysis report.

n. In the control cost worksheets, a retrofit factor of 1.5 was selected from a recommended range between 0.8 and 1.5 for retrofitting the boilers with SCR. Please note that the CCM for SCR allows a retrofit factor of greater than one (1) provided the reasons for using the higher retrofit factor are appropriate and fully documented. A note in the control cost spreadsheet indicated that a retrofit factor of 1.5 is appropriate for the proposed project due to Hawaiʻi's remote location. For selecting a retrofit factor of greater than one (1), please provide additional detail on the complexities involved for retrofitting the boilers with SCR at the Kahe Generating Station.

   Response –The EPA Air Pollution Control Cost Manual (CCM) recommends a retrofit factor of 0.8 should be used for new construction and a retrofit factor of 1 should be used for average retrofits. The CCM lists the following specific factors that impact retrofit costs:

   - The amount of available space between and around the economizer and air heater;
   - Congestion downstream of the air heater (i.e., buildings, ID fan, or stack);
   - The age/vintage and manufacturer of the boiler;
   - The design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
   - The capacity, condition, and design margins of the electrical distribution system;
   - The design margins of the existing structural steel support systems;
   - The positive and negative design pressure of the furnace; and
     The number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

Although all of the factors listed above will impact the retrofit costs for the Kahe boilers, to determine the specific degree of impact for each individual factor would require a more detailed engineering study to evaluate, provide, and itemize the cost impact of the above factors. It is estimated that such an engineering study could take an up to ten (10) months to complete at a cost of approximately $532,500 for the Kahe Generating Station. In addition, Hawaiʻi's higher construction cost impacts the cost to address the required equipment upgrades and space constraints which require relocation of existing equipment. Based on these factors, rather than engage in additional time consuming and costly studies, the more conservative upper range of the retrofit factor was selected.

o. Appendix B of the four-factor analysis indicated that, in the recent past, Hawaiʻi's volcanic SO_2 emissions are about 1,000 times greater than anthropogenic SO_2 emissions and volcanic activity in Hawaiʻi produced as much as two (2) million tons of SO_2 per year. Please note that SO_2 emissions have significantly decreased after the Kilauea eruption ended in September 2018. The United States Geological Survey (USGS) stated, that in 2019, the summit is the only source releasing enough SO_2 emissions to be quantified using ultra-violet spectroscopy. Preliminary USGS results for 2019 indicate an average summit daily SO_2 emission rate of about 43 tons and an annual total SO_2 emission rate of about 17,119 tons which is far lower than the two (2) million tons of SO_2 reported to be emitted by the volcano in Appendix B. Note that the total combined SO_2 emissions from point sources screened for four-factor analyses were about 18,058 tons per year in 2017 which is 939 tons higher than preliminary USGS estimates of volcanic SO2 for 2019. Since Kilauea eruption activity ended in September 2018, point sources screened for four-factor analysis now play a more significant part in SO_2 visibility impacts.

Response – Hawaiian Electric agrees that the volcanic SO_2 emissions have significantly decreased since September 2018. The four-factor analysis report Appendix B will be updated to acknowledge this change in the volcanic emissions. However, Hawaiian Electric does not believe that this changes the overall conclusion of the analysis which indicated that the Hawaiian Electric power plants are not significant contributors to visibility impairment at Hawaiʻi's Class I areas. Although the percent impact of point sources will increase with less volcanic emissions, the absolute value of the point source impacts remains unchanged. Given the neglible impact, the cost of control measures cannot be justified.

Hawaiian Electric sources on Oʻahu are not upwind of either Class I area and do not have any significant impact on the visibility at either area. As mentioned in the four-factor analysis report, EPA CALPUFF modeling conducted for the First Decadal Review confirms the expected low impacts from these Hawaiian Electric sources.

As discussed in Section 2.1 of the four-factor analysis report, Step 1 of the EPA SIP guidance is to identify the 20 percent most anthropogenically impaired days, which requires factoring out volcanic impacts. Hawaiian Electric understands that volcanic activity has decreased since the September 2018. The reduction in volcanic activity should be visible in the 2019 IMPROVE monitoring data. The DOH should review the 2019 IMPROVE monitoring data to assist with defining the level of anthropogenic impaired.

Additionally, Hawaiian Electric, as a key affected company, should be allowed to participate as a major stakeholder in discussing and reviewing the EPA's photochemical modeling and the Western Regional Air Partnership's Hybrid-Single Particle Lagrangian Integrated Trajectory (HYSPLIT) modeling mentioned during the conference call with Hawaiian Electric and the DOH on July 30, 2020.

p. Appendix B of the four-factor analysis also noted that volcanic activity on Hawaiʻi Island is the largest source of NO_X in the state based on a NO_X emission estimate for the Kilauea Volcano of roughly 125,000 tons per year. Data, indicating worldwide volcano NO_X and SO_2 emissions of 1.5 and 23 teragrams, respectively, was used for the estimate. It was stated that the NO_x was likely caused by thermal contact of air with lava. Based on the NO_X/SO_2 ratio using the worldwide numbers, it was then assumed that NO_X emissions from Kilauea Volcano are about 6% of the volcano's total SO_2 emissions. It was also assumed that Hawaiʻi volcanic activity emits approximately two (2) million tons per year of SO_2. Please note that he global ratio of NO_X/SO_2 is likely not appropriate to use for estimating NO_X emissions from the Kilauea Volcano. Interagency Monitoring of Protected Visual Environments data shows that annual light extinction from ammonium nitrates for the most impaired days at Haleakala National Park over the current visibility period (2014-2018 when the volcano was erupting) are higher than those at Hawaiʻi Volcanoes National park where the volcano is located. Also, while volcanic SO_2 emissions were reported to be as high as two (2) million tons per year when the Kilauea Volcano was erupting, SO_2 emissions have significantly decreased after the Kilauea eruption ended in September 2018. There currently is no lava in the Kilauea summit crater. Instead, a lake of water has formed in the Kilauea crater after the volcano stopped erupting towards the end of 2018. Please refer to: https://earthobservatory.nasa.gov/images/146687/a-new-lakewater-not-lavaon-kilauea.

  Response – Hawaiian Electric recognizes that estimates of NO_X emissions from the volcano are uncertain as are the significance of its impact to nitrate haze. Appendix B of the four-factor analysis report will be updated to recognize this and acknowledge that monitoring data does not suggest a large impact from the volcanos. However, more importantly, as discussed in the four-factor analysis report, monitoring data for both National Parks shows that the total contribution of nitrates from all sources to haze is very low as both a percentage of the total impairment, and is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter ("Mm-1"), an extremely small value which is the total due to ALL sources, natural and anthropogenic. The small impact of NOx emissions to haze formation is due to the unique chemistry of nitrate haze and Hawaiʻi's generally warm weather year-round as explained in the four-factor analysis report.

  Regarding the noted significant decrease in volcanic SO_2 emissions, see the previous response to item o.

q. In the four-factor analysis, HECO states that no reduction measures in addition to Hawaiʻi's Renewable Portfolio Standards (RPS) are proposed to meet the RHR requirements. While provisions mandated by the RPS are subject to enforcement action by the Hawaiʻi Public Utilities Commission, these are state only enforceable requirements which are not federally enforceable under the federal Clean Air Act. The RHR requires federally enforceable emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional Haze. As an option, HECO may propose caps for the emissions of visibility impairing pollutants (SO_2, NO_X, and PM_{10}) based on anticipated emission reductions from the RPS as a reasonable progress measure that could be incorporated into permits. These emission caps would need to occur in the second planning period (2018-2028) in order to be credited as a control measure for reasonable progress. Additional measures for showing reasonable progress include federally enforceable plant shutdowns as described in comment e above. In essence, HECO could propose: 1) federally enforceable conditions for retiring units during the second implementation planning period (2018-2028) and include those units and retirement dates in the four factor analyses along with a four factor analysis of the remaining equipment; 2) propose federally enforceable emission control measures such as fuel switching or add-on controls with the associated pollutant reductions, or 3) propose federally enforceable permit limits such as emission caps, for operational flexibility, or hour restrictions with the associated compliance dates or any combination of 1, 2, or 3 above.

Response As Hawaiian Electric set forth in the four-factor analysis report (see in particular Appendix C) continues to assert that several of its programs can in fact be used to show that their emissions are being reduced in a manner that shows reasonable progress.

EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance) allows for the use of renewable energy programs as an alternative to permit limits. Also, the SIP Guidance encourages the use of projected 2028 emissions in selecting emission controls required to show reasonable progress and allows for energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes. Hawaiian Electric's progress towards meeting the RPS is documented in annual reports to the Public Utility Commission (PUC) see also Appendix C to the Four Factor Reports. In addition, the status of future renewable projects are listed on the *Renewable Project Status Board* on the Hawaiian Electric website. [11] The addition of renewable energy is an operational change that reduces fossil fuel consumption, which results in reductions in emissions of visibility impairing pollutants.

The EPA's Regional Haze SIP Guidance supports the use of the State's RPS as an alternative to permit limits as it states:

" ***Step 3: Selection of sources for analysis***

…

Selection of emissions information when estimating visibility impacts (or surrogates) for source selection purposes

******

All of the techniques described above require estimates of source emissions. Generally, we recommend that states use estimates of 2028 emissions (resolved by day and hour, as appropriate) to estimate visibility impacts (or related surrogates) when selecting sources, rather than values of recent year emissions. By doing so, sources that are projected on a reasonable basis to cease or greatly reduce their operations or to install much more effective emissions controls by 2028 may be removed from further consideration early in the SIP development process, which can reduce analytical costs. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions in a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters <u>and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.</u> A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office.

If a state uses a value for emissions in an earlier year, we recommend the state consider whether emissions have appreciably changed (or will change) between the earlier year, the current period, and the projected future year (2028). It is especially important to consider whether source emissions have increased or are likely to increase in the future compared to earlier emissions values.

[11] Renewable Project Status Board (https://www.hawaiianelectric.com/clean-energy-hawaii/our-clean-energy-portfolio/renewable-project-status-board)

Use of actual emissions versus allowable emissions
Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 actual emissions for purposes of selecting sources for control measure analysis. Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered, along with factors that indicate a likely increase or decrease in operation.
…
Step 4: Characterization of factors for emission control measures
…
Examples of types of emission control measures states may consider States have the flexibility to reasonably determine which control measures to evaluate, and the following is a list of example types of control measures that states may consider:
…
Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.
…
EPA understands that some states may be interested in exploring such measures for their second implementation period SIPs, which is generally appropriate. We suggest such states discuss the measures and programs and their incorporation into the SIP with their EPA Regional office..." [12]

Based on the above EPA guidance, the selection of controls for the long-term strategy (LTS) can include alternatives to permit limits and rely on projected emissions based on the planned transition to 100% renewable energy. For example, various RPS goals across the 48 contiguous states were used as inputs in the EPA's Integrated Planning Model (IPM)[13,14] to project EGU emissions. The CAM_X modeling used these projected emissions to support the LTS for 2028 (SIP Guidance Steps 5 and 6).

Hawaiian Electric is willing to work with the DOH and EPA Region IX on an alternative to permit limits that relies on the State's RPS goals. The State of Hawai'i apparently contemplated that both the RPS and GHG emissions cap could be used to show reasonable progress in the 2018 Western States Planning Readiness Survey For Regional Haze State Implementation Plans For The Second Implementation Period Survey Results And Discussion (Readiness Survey)[15].

The Readiness Survey that was conducted by the Western Regional Air Partnership (WRAP) states:

Hawaiian Electric plans to use Hawai'i's existing Renewable Portfolio Standard (RPS) as a measure to make reasonable progress. The RPS ultimately requires the Hawaiian Electric Company to establish 100% renewable energy sales by 2045 to reduce fossil fuel consumption for mitigating GHGs. Mitigating GHGs will also reduce pollutants that impair visibility as a co-benefit. Hawaiian Electric Companies' Power Supply Improvement Plan (PSIP) provides future plans for the utility

[12] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, page 17, August 2019, EPA-457/B-19-003. https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

[13] Technical Support Document for EPA's Updated 2028 Regional Haze Modeling, pages 11-12, September 2019. https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

[14] Power Sector Modeling Platform v6 November 2018. https://www.epa.gov/airmarkets/power-sector-modeling-platform-v6-november-2018

[15] 2018 (final 1/2019) Western States Planning Readiness Survey For Regional Haze State Implementation Plans For The Second Implementation Period Survey Results And Discussion. https://www.wrapair2.org/pdf/WRAP%202018%20RH%20Planning%20Readiness%20Survey%20-%20Synthesis%20Report%20FINAL%20(including%20figures%20and%20attachments).PDF

> *and independent power producers to achieve 100% RPS by 2045. The PSIP may be used to establish permit conditions to limit the emissions of pollutants that impair visibility for meeting reasonable progress goals. In accordance with our Hawaiʻi Administrative Rules (HAR), point sources are subject to a GHG emission cap to ensure emissions from stationary sources (both minor and major) return to 1990 GHG levels by 2020. The GHG emissions cap must be at least 16% below the baseline level unless the affected facility demonstrates that a 16% reduction is unattainable.*

Although based on the analysis herein, we do not believe that permit conditions are required to use the RPS to show progress, nor is it practical to do so given the difficulty in predicting the specifics of the RPS progress. However, Hawaiian Electric intends to provide a further analysis that may include additional strategies to include these two programs in its updated four-factor analysis report.

Revised Four – Factor Analysis

REGIONAL HAZE FOUR-FACTOR ANALYSIS
Kahe Generating Station

Hawaiian Electric

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April 2020
Revised September 14, 2020
Revised September 25, 2020

Project 194401.0297

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This report is submitted to comply with the second implementation period of the Regional Haze Rule (RHR). In the first implementation period, the EPA excluded sources, such as the Kahe Generating Station (Kahe), which is located on the Island of Oahu, from its analysis because of the distance and downwind location of the sources in relation to the Class I areas in Hawaiʻi.

The State of Hawaiʻi has two Class I areas (National Parks) that trigger compliance with the RHR: Hawaiʻi's Mandatory Federal Class I Areas are Haleakalā National Park on Maui and Hawaiʻi Volcanoes National Park on Hawaiʻi Island. This report documents the results of a four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric[1] for the six boilers (K1, K2, K3, K4, K5, and K6) at Kahe. K1, K2, K5, and K6 are wall-fired boilers with nominal ratings of 92 megawatts (MW), 90 MW, 142 MW, and 142 MW, respectively. K3 and K4 are tangentially-fired boilers with nominal ratings of 92 MW and 93 MW, respectively. The boilers currently burn residual oil (residual oil, residual low sulfur fuel oil, or LSFO). Also, Appendix B and Appendix C contain analyses performed by AECOM Technical Services, Inc. (AECOM) of a fifth factor that includes a review of visibility impacts.

This report addresses the options that could be considered that have the potential to lower emissions and show reasonable progress toward the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period for Kahe. Other long-term emissions reduction strategies, such as those included as part of Hawaiʻi's Renewable Portfolio Standards (RPS), the Hawaiian Electric Partnership Greenhouse Gas Emissions Reduction Plan (GHG ERP) required by Act 234 and the associated DOH GHG Emissions Regulations (Hawaii Administrative Rules Title 11, Chapter 60.1, Subchapter 11) which require State enforceable GHG emissions limits, and Hawaiʻi's Energy Efficiency Portfolio Standard (EEPS) are viable alternatives to emissions reductions from add-on controls and changes in the method of operations.

Hawaiian Electric and AECOM met with the Department of Health (DOH) on February 12, 2020 to present special circumstances applicable in Hawaiʻi that should be given consideration in the development of the Hawaiʻi Regional Haze State Implementation Plan (SIP). Significant among those circumstances is Hawaiʻi's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty (20) years before the Regional Haze 2064 target date and that this facility is a considerable distance and mostly downwind of the Class I areas. These same issues were addressed by the EPA in the Federal Implementation Plan (FIP) and the DOH in its Progress Report[2] that was approved by the EPA effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report.

Based on the four-factor analysis and the materials set forth in the appendices, Hawaiian Electric does not propose any emissions reduction measures in addition to the Hawaiʻi RPS, EEPS, and the GHG ERP to meet the RHR requirements.

[1] Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawaiʻi Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawaiʻi Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

[2] 5-Year Regional Haze Progress Report for Federal Implementation Plan, Hawaiʻi State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

ensure that reasonable progress is made during this first planning period toward the national goal of no anthropogenic visibility impairment by 2064 at Hawaiʻi's two Class I areas.

The second implementation planning period (2019-2028) for the national regional haze efforts is currently underway. The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)[4] provides guidance to states for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade (or "anthropogenic") sources of emissions. The EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)[5] provides guidance to states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. The approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions; however, the 2017 RHR defines visibility impairment or anthropogenic visibility impairment as:

> *any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.*

Specifically, the EPA's Visibility Guidance states that although they did not attempt to account for haze formed by natural volcanic emissions:

> *We encourage states with Class I areas affected by volcanic emissions to work with their EPA Regional office to determine an appropriate approach for determining which days are the 20 percent most anthropogenically impaired days.*

In the *5-Year Regional Haze Progress Report for Federal Implementation Plan*[6], the DOH acknowledges the impact of SO_2 from the Kilauea volcano with the following statement:

> *A majority of the visibility degradation is due to the ongoing release of SO_2 from Kilauea volcano with emissions that vary by hundreds of thousands of tons from one year to another. Visibility improvement from significant reductions in Maui and Hawaii Island point source SO_2 is obscured by sulfate from natural volcanic SO_2 that overwhelms sulfate from anthropogenic SO_2 sources.*

Step 1 of the EPA's SIP Guidance is to identify the twenty (20) percent most anthropogenically impaired days and the twenty (20) percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state (40 CFR 51.308(f)(1)). Hawaiian Electric has concerns that this key step may not be accounted for during the second implementation planning period and the development of Hawaiʻi's RHR SIP. The identification of the twenty (20) percent most impaired days sets the foundation for identifying any needed emissions reductions.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this the Western Regional Air Partnership (WRAP), with Ramboll US Corporation, reviewed the 2014 National Emissions Inventory (NEI) and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. The WRAP Guidance states that the EPA has concerns over only relying on the Q/d method for

[4] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

[5] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010.

[6] 5-Year Regional Haze Progress Report for Federal Implementation Plan, Hawaiʻi State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

screening sources. The EPA points out that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport direction/pathway and dispersion and photochemical processes. To address the EPA's concern, the WRAP subcommittee recommends a second step, application of the weighted emissions potential analysis (WEP).[7] On September 11, 2019, the DOH informed Hawaiian Electric, that Kahe Generating Station (Kahe) was identified as one of the sources potentially contributing to regional haze at the Haleakalā National Park and Volcanoes National Park. This report responds to the DOH September 2019 request to Hawaiian Electric to submit a four-factor analysis for Kahe.

The "Q/d" approach does not take into consideration the frequency or actual visibility impact on the Class I area. In support of the SIP for the first planning period, modeling was conducted for several facilities[8] located on the island of Oahu. Regional haze modeling shows these facilities had an insignificant impact on visibility at Haleakalā and Volcanoes National Parks. Therefore, Hawaiian Electric encourages the DOH to consider actual visibility impacts in the SIP development process.

The SIP Guidance requires that the selection of sources and controls necessary to make reasonable progress must, in addition to the statutory four factors (cost, remaining useful life, etc.), also consider the five required factors listed in 40 CFR section 51.308(f)(2)(iv), and other factors that are reasonable to consider.[9] These additional factors include consideration of emissions reductions due to ongoing air pollution control programs and the anticipated net effect on visibility due to projected changes in source emissions. The Hawaiian Electric and AECOM prepared summary, included in Section 2.2, describes special circumstances applicable in Hawaiʻi that should be considered during the development of the Hawaiʻi Regional Haze SIP.

2.2. ADDITIONAL FACTORS

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances applicable in Hawaiʻi that should be considered during the development of the Hawaiʻi Regional Haze SIP. Significant among those circumstances is Hawaiʻi's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the Regional Haze 2064 target date. These same issues were addressed by the EPA in the FIP and the DOH in their Progress Report that as approved by the EPA, effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report and summarized in the following sections.

Additionally, Kahe is subject to the DOH's GHG ERP and the associated State enforceable Covered Source Permit limit and thereby, also reduces emissions relevant to the RHR.

2.2.1. Lack of Contribution to Visibility Impairment Due to Prevailing Winds

As noted above, the DOH did not consider actual contribution to visibility impairment when selecting sources for the Four-Factor Analysis, but this is a critical factor in establishing realistic reasonable progress goals for Class I areas. The EPA's FIP for Hawaiʻi for the First Decadal Review (77 FR 61478,

[7] WRAP Reasonable Progress Source Identification and Analysis Protocol For Second 10-year Regional Haze State Implementation Plans, dated February 27, 2019 (https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf).

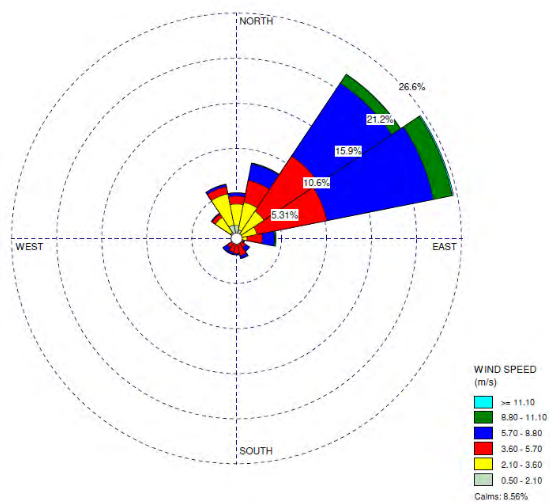
[8] Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012. Table VI-3 provides visibility modeling results for the following Oahu facilities: Chevron Refinery, Tesoro Refinery, and Hawaiian Electric's Kahe and Waiau power plants.

[9] US EPA Memorandum, "Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program", Dec. 20, 2018, Pages 9, 21, C-1.

October 9, 2012) has already acknowledged the predominant trade winds in Hawai'i and thus, did not require controls on upwind sources (i.e., sources on Oahu and Maui).

The wind rose plot for the Honolulu airport on Oahu shows that the wind is almost always from the northeast and rarely blows from the west or northwest, directions necessary for emissions from Kahe to blow toward either of Hawai'i's Class I areas. The Honolulu airport wind rose plot is provided as Figure 2-1 and shows the persistence of the northeasterly trade winds. Based on the infrequent amount of time the wind blows from Kahe toward either of Hawai'i's Class I areas, it is unlikely that the facility's potential emissions impact visibility at Haleakalā National Park and Volcanoes National Park. Therefore, when balancing retrofit costs and visibility improvements, the DOH should remain mindful that emissions from this facility are unlikely to contribute to regional haze at Haleakalā National Park and Volcanoes National Park and as such will have no impact on a showing of further reasonable progress.

Figure 2-1. Honolulu Wind Rose (2015 – 2019) Predominant Wind from the Northeast



2.2.2. Lack of Contribution to Visibility Impairment Due to Warm Weather Conditions

The potential for the formation of haze due to NO_X emissions is very low in Hawai'i because of the warm weather conditions year-round. Nitrate haze composition analyses for the Haleakalā and Hawai'i Volcanoes National Parks from the IMPROVE web site are included in Appendix B to this report. The data for both national parks show that the contribution of nitrates to haze is very low. It is low as a percentage of the total haze composition, but it is also low as an absolute value for light extinction (visibility impairment). The minimal impact of nitrate haze is clearly illustrated in the Hawai'i National Park monitoring data and is much lower than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze which is discussed further in Appendix B to this report.

Due to the low haze impact of NO_X, the DOH should not consider NO_X controls for the Second Decadal Review for Kahe. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_X controls to be material.

2.2.3. Contribution to Visibility Impairment from Volcanic Activity

Volcanic activity on the Hawaiʻi Island represents a unique challenge to understanding haze in Hawaiʻi Class I areas. The Kilauea volcano on Hawaiʻi Island has been active for several years, and the levels of SO_2 emissions are being monitored by the United States Geological Survey. In addition to volcanoes being large sources of SO_2, they also emit significant amounts of NO_X. Volcanic activity on Hawaiʻi Island is by far the largest source of both SO_2 and NO_X in the state and so dominates visibility impairment to Class I areas as to completely obscure any small impact from anthropogenic sources. Significant portions of direct Particulate Matter (PM) emissions are due to volcanic activity. Whatever small impact of SO_2 NO_X, and PM emissions from power plants are projected to be eliminated well before the end point of the Regional Haze Rule (i.e., 2064) by Hawaiʻi's Statutory Renewable Portfolio Standards (RPS). Thus, the DOH should not consider SO_2, NO_X, or PM controls for the Second Decadal Period Review for Kahe.

2.2.4. Renewable Portfolio Standards

For the reasons stated above and based on AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO_2, NO_X, and particulate matter, 10 microns or less in diameter (PM_{10}) emissions from Kahe do not significantly contribute to regional haze at the Class I areas. The low impact that Kahe may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawaiʻi Revised Statute (HRS) §269-92) and consistent with the Hawaiʻi Clean Energy Initiative (HCEI). Both past and projected future decreases in fossil-fueled electric generating unit (EGU) usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO_2) by 2045. Therefore, further requirements for controls at Kahe would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaiʻi Progress Report for Phase 1), it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

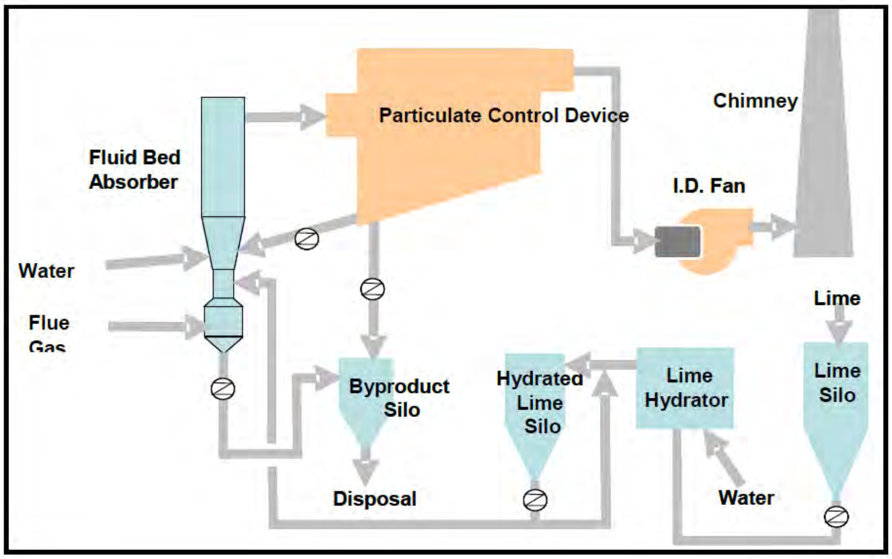
3.1.1. Post-Combustion Controls

3.1.1.1. Boilers

FGD applications have not been used historically for SO_2 control on oil-fired boilers. As there are no known FGD applications for oil-fired boilers, the performance of FGDs on oil-fired boilers is unknown. An internal engineering study in 2012 identified CDS as the best option, if required, for the Kahe Boilers. Since there are no applications of FGD on oil-fired boilers in the U.S., FGDs, including CDS, are considered unproven technology for the control of SO_2 from the Kahe boilers due to lack of similar applications. However, the cost effectiveness of CDS is evaluated for completeness. The SO_2 cost-effectiveness calculations show that CDS is the least cost-effective option to reduce SO_2.

The CDS process uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. The process starts when flue gas enters multiple venturi nozzles at the base of a vertical reactor tower, where it is humidified by a water mist before entering the circulating bed of powdered hydrated lime, fly ash, and recycled byproducts. Figure 3-1 shows a typical process flow diagram of a CDS system. The addition of CDS is expected to reduce SO_2 emissions by ninety percent.

Figure 3-1. Typical CDS system



3.1.2. Fuel Switching

The Kahe boilers currently burn residual low sulfur fuel oil with a maximum sulfur content of 0.5 percent by weight. The average sulfur content of the residual low sulfur fuel oil burned in 2017 was approximately 0.42 percent by weight. Switching to a lower sulfur fuel will reduce SO_2 emissions in proportion to the reduction in fuel sulfur content.[10] However, a lower sulfur residual oil is not currently available in Hawai‘i. Lower sulfur content distillate fuels are available and could be burned in the boilers or could be blended with the existing residual low sulfur fuel oil to lower the sulfur content. Technically feasible options include blending the current residual low sulfur fuel oil with a lower sulfur distillate fuel or switching to a lower sulfur distillate fuel. The SO_2 four-factor analysis evaluates both options.

[10] Natural gas has less sulfur than the existing residual oil. However, natural gas is not a technically feasible option because there is no utility-scale natural gas supply in Hawai‘i.

3.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO_2 emissions from Kahe do not significantly contribute to regional haze. The low impact that Kahe may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawaiʻi Revised Statute (HRS) §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO_2) by 2045. Therefore, further requirements for controls at Kahe would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaiʻi Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, the technically feasible options to reduce SO_2 emissions are:

- CDS;
- Fuel switching to a residual/distillate blended fuel; or
- Fuel switching to a lower sulfur distillate fuel.

For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors are discussed in the following sections.

3.2.1. Cost of Compliance

The cost effectiveness of CDS was based on the annualized cost of the CDS divided by the reduction in SO_2 emissions. The cost effectiveness of the fuel switching was determined by calculating the annual incremental cost of switching to a lower sulfur fuel divided by the reduction in SO_2 emissions. Switching fuel would require changes to the injectors and the fuel system; however, these expenses were not included in the analysis.

Kahe currently purchases residual low sulfur fuel oil from Par Hawaii Refining, LLC (Par Hawaii); current fuel costs are provided in Appendix D. The current residual low sulfur fuel oil is refined on Oahu and changes in quantities of residual low sulfur fuel oil and ULSD would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance. Par Hawaii is the only refinery in Hawaiʻi and is near production capacity of ULSD. Therefore, increases in ULSD will require importing ULSD to Hawaiʻi and Appendix D contains the estimated cost of importing ULSD to Hawaiʻi.

Table 3-2 presents the cost effectiveness of adding CDS to the boilers. The cost effectiveness is determined by dividing the annualized cost by the annual reduction in SO_2 emissions. The cost effectiveness of adding CDS systems ranges from $13,195 to $18,281 per ton of SO_2 in the different units and the total cost equals 80 million dollars ($80,000,000) annually and 2.4 billon dollars ($2,400,000,000) over thirty (30) years.

Table 3-2. SO_2 Cost effectiveness of CDS

Unit	Control Option	2017 SO_2 Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	CDS	841.8	0.045	3,778,041	84.2	757.6	$10,608,072	$14,002
K2	CDS	659.5	0.045	2,959,869	66.0	593.6	$10,800,319	$18,196
K3	CDS	836.3	0.045	3,753,356	83.6	752.7	$11,589,051	$15,397
K4	CDS	859.8	0.045	3,858,826	86.0	773.8	$11,023,741	$14,246
K5	CDS	1,136.2	0.045	5,099,323	113.6	1,022.6	$18,694,104	$18,281
K6	CDS	1,431.5	0.045	6,424,644	143.2	1,288.4	$17,000,254	$13,195

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] Controlled emission levels based on 90% control.

[C] See Appendix A for total annual cost calculations.

Table 3-3. SO_2 Cost effectiveness of Fuel Switching to a Residual Oil/ULSD Blend

Unit	Current Residual Oil (0.50% maximum Sulfur) [A]					Residual Oil/ULSD Blend (0.25% maximum Sulfur) [B]						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO_2 Emissions [D] (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (tpy)	Fuel Cost Differential [C] ($/Gal)	Fuel Cost Differential [C] ($/yr)	SO_2 Cost Effectiveness ($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	143,071	26,406,754	493.0	348.8	0.18	$4,621,182	13,250
K2	0.42%	149,479	19,801,237	2,959,869	659.5	143,071	20,688,114	386.3	273.2	0.18	$3,620,420	13,250
K3	0.42%	149,479	25,109,590	3,753,356	836.3	143,071	26,234,222	489.8	346.5	0.18	$4,590,989	13,250
K4	0.42%	149,479	25,815,168	3,858,826	859.8	143,071	26,971,403	503.6	356.2	0.18	$4,719,995	13,250
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	143,071	35,641,903	665.5	470.7	0.18	$6,237,333	13,250
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	143,071	44,905,284	838.4	593.1	0.18	$7,858,425	13,250

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on a blend of 50.0% residual oil and 50.0% ULSD and the weighted averge of the 2017 fuel HHV and density for residual oil and ULSD, and contract fuel sulur limits.

[C] See Appendix D for fuel cost.

[D] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-4. SO_2 Cost effectiveness of Fuel Switching to ULSD

Unit	Current Residual Oil (0.50% maximum Sulfur) [A]					ULSD (0.0015% maximum Sulfur) [B]						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO_2 Emissions [D] (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (tpy)	Fuel Cost Differential [C] ($/Gal)	Fuel Cost Differential [C] ($/yr)	SO_2 Cost Effectiveness ($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	136,662	27,645,144	3.8	838.0	0.36	$9,814,026	11,711
K2	0.42%	149,479	19,801,237	2,959,869	659.5	136,662	21,658,318	3.0	656.5	0.36	$7,688,703	11,711
K3	0.42%	149,479	25,109,590	3,753,356	836.3	136,662	27,464,521	3.8	832.5	0.36	$9,749,905	11,711
K4	0.42%	149,479	25,815,168	3,858,826	859.8	136,662	28,236,273	3.9	855.9	0.36	$10,023,877	11,711
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	136,662	37,313,391	5.1	1,131.1	0.36	$13,246,254	11,711
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	136,662	47,011,195	6.4	1,425.1	0.36	$16,688,974	11,711

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

[C] See Appendix D for fuel cost.

[D] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

emissions. Post-combustion controls convert NO_X in the flue gas to molecular nitrogen and water. Available NO_X control technologies for the boilers are:

- Fuel Switching to a residual/distillate blended fuel or a distillate fuel
- Combustion Controls (K1 – K5)
  - Flue Gas Recirculation (FGR)
  - Overfire Air (OFA)
  - Low NO_X Burners (LNB)
- Post-Combustion Controls (K1 – K6)
  - Selective Catalytic Reduction (SCR)
  - Selective Non-Catalytic Reduction (SNCR)
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

4.1.1. Fuel Switching

The Kahe boilers currently burn residual oil. Blending the current residual oil with distillate fuel or switching to a distillate fuel will result in minor reductions in NO_X emissions due to the lower fuel bound nitrogen content. The NO_X four-factor analysis evaluates both options. Table 4-2 provides the estimated control levels for fuel switching.

Table 4-2. NO_X Reduction from Fuel Switching

	AP-42 NO_X Emission Factors [A]		Percent NO_X Reduction from Fuel Switching [B]		
	Wall-Fired Boilers	Tangentially-Fired Boilers			
Fuel Scenario	(lb/MMBtu)	(lb/MMBtu)	K1, K2 & K5	K3 & K4	K6 [C]
Residual Oil (LSFO)	0.313	0.213	--	--	--
Distillate (No. 2 Fuel Oil)	0.171	0.171	45%	20%	36%
Residual Oil w/LNB [C]	0.267	--	--	--	--
50/50 Blend	--	--	23%	10%	18%

[A] The listed emission factors are from AP-42, Table 1.3-1, dated May 2010.

[B] The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

[C] K6 is equipped with LNB.

4.1.2. Combustion Controls

4.1.2.1. Flue Gas Recirculation (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_X formation. When FGR is operated without additional controls, the NO_X control range for wall-fired boilers (K1, K2, and K5) with FGR is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[15] This control is a technically feasible option for the Kahe boilers. When FGR is combined with LNB, the estimated NO_X control range on wall-fired boilers with LNB (K6) is approximately 0.20-0.25 lb/MMBtu which is includes the K6's permitted NO_X

[15] *Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler*, EPA, 1994.

limit of 0.23 lb/MMBtu. Therefore, the addition of FGR to K6 with LNB is not expected to significantly reduce NOX emissions.

4.1.2.2. Overfire Air (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. When OFA is operated without additional controls, the NO_X control range for wall-fired boilers (K1, K2, and K5) is approximately 0.30-0.45 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.20-0.30 lb/MMBtu.[16] This control is a technically feasible option for the Kahe boilers. When OFA is combined with LNB, the estimated NO_X control range on wall-fired boilers with LNB (K6) is approximately 0.25-0.30 lb/MMBtu which is close to K6's permitted NO_X limit of 0.23 lb/MMBtu. Therefore, the addition of OFA to K6 with LNB is not expected to significantly reduce NO_X emissions.

4.1.2.3. Low NO_X Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

The estimated NO_X control range for LNBs on wall-fired boilers (K1, K2, and K5) is approximately 0.25-0.35 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[17] When combined with OFA, the estimated NO_X control range on wall-fired boilers (K1, K2, and K5) is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (K3 and K4) is approximately 0.15-0.20 lb/MMBtu.[18] LNB systems and LNB systems with OFA are technically feasible for the Kahe boilers K1, K2, K3, K4, and K5.

4.1.3. Post Combustion Controls

4.1.3.1. Selective Catalytic Reduction (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

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

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, catalyst, ammonia storage, and an ammonia injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The

[16] Ibid.
[17] Ibid.
[18] Ibid.

Table 4-3. Control Effectiveness of Technically Feasible NO_X Control Technologies

	Estimated Controlled Level	
	Wall-Fired Boilers	Tangentially-Fired Boilers
Control Technology	(lb/MMBtu)	(lb/MMBtu)
SCR+Combustion Controls	0.05	0.05
SCR	0.05 - 0.10	0.03 - 0.10
LNB & OFA	0.25 - 0.30	0.15 - 0.20
FGR	0.25 - 0.30	0.15 - 0.20
LNB	0.25 - 0.35	0.15 - 0.20
SNCR+Combustion Controls	0.20 - 0.40	0.15 - 0.25
SNCR	0.30 - 0.40	0.20 - 0.25
OFA	0.30 - 0.45	0.20 - 0.30
Fuel Switching	0.27 - 0.62	0.28 - 0.34

The control levels in Table 4-3 are presented as a range because the specific level of control that is achievable for the Kahe boilers based on the application of the controls listed in Table 4-3 is unknown. Engineering studies would be required for each boiler to determine the best combustion control option or combinations of control options and the level of control achievable. It is estimated that such an engineering study could take an up to ten (10) months to complete at a cost of approximately $532,500 for the Kahe Generating Station. It is anticipated that combustion controls such as LNB with OFA, or LNB with FGR and possibly LNB, FGR, or OFA alone can achieve NO_X emission levels of approximately 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4. As noted in Table 4-1, the Kahe boilers are currently emitting in the range of 0.196 lb/MMBtu to 0.802 lb/MMBtu. Further, it is believed that SCR can achieve a NO_X emissions level of approximately 0.10 lb/MMBtu and 0.05 lb/MMBtu when SCR is combined with combustion controls. The addition of SNCR can achieve a NO_X emissions levels of 0.40 lb/MMBtu for K1, K2, and K5, 0.15 lb/MMBtu for K6 and 0.25 lb/MMBtu for K3 and K4. SNCR combined with combustion controls can achieve a NO_X emissions levels of 0.20 lb/MMBtu for K1, K2, and K5 and 0.15 lb/MMBtu for K3 and K4.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching, combustion controls, SNCR and SCR are the best feasible options to reduce NO_X emissions from the boilers. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for adding NO_X controls are discussed in the following sections.

4.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of combustion controls, SNCR, and SCR have been estimated for the boilers. The cost effectiveness of combustion controls is based on a controlled NO_X emissions level of 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4. At this time, it is unknown if LNB, OFA or FGR alone can achieve this level of emissions or if LNB combined with OFA or FGR would be required to meet this level. Therefore, the costing is based on the range of cost for LNB with OFA, the cost of FGR and LNB with FGR are expected to be covered by this range and have a similar level of NO_X control. The costing assumes that a NO_X emissions level of 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4 can be achieved with combustion controls. This level of NO_X emissions is comparable to SNCR; the only other control expected to result in lower achievable NO_X emissions is SCR. The cost effectiveness of SNCR is based on a NO_X emissions levels of 0.40 lb/MMBtu for K1, K2, and K5, 0.15 lb/MMBtu for K6 and 0.25 lb/MMBtu for K3 and K4. The cost effectiveness of SNCR combined with combustion controls is based on a NO_X emissions levels of 0.20 lb/MMBtu for K1, K2, and K5 and 0.15 lb/MMBtu for K3 and K4. The cost effectiveness of SCR is based on a controlled NO_X emissions level of 0.10 lb/MMBtu and 0.05 lb/MMBtu when combustion controls are combined with SCR. The cost of fuel switching is discussed in Section 3.2.1.

Table 4-4 presents a summary of the cost effectiveness of fuel switching, adding combustion controls, SNCR, SNCR combined with combustion controls, SCR and SCR combined with combustion controls to the boiler. The cost effectiveness is determined by dividing the annual cost by the annual reduction in NO_X emissions. The cost effectiveness of fuel switching ranges from $13,266 per ton to more than $70,000 per ton of NO_X emissions in the different units and the total cost exceeds 32 million dollars ($32,000,000) annually and 960 million dollars ($960,000,000) over thirty (30) years. The cost effectiveness of combustion controls ranges from $499 per ton to $1,318 per ton of NO_X emissions in the different units and the total cost equals 2 million dollars ($2,000,000) annually and 60 million dollars ($60,000,000) over thirty (30) years. The cost effectiveness of SNCR ranges from $1,326 per ton to $4,824 per ton of NO_X in the different units and the total cost equals 5 million ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years. The cost effectiveness of SNCR plus combustion controls ranges from $1,302 per ton to $2,987 per ton of NO_X in the different units and the total cost exceeds 7 million ($7,000,000) annually and 210 million dollars ($210,000,000) over thirty (30) years. The cost effectiveness of SCR ranges from $1,709 per ton to $6,488 per ton of NO_X emissions in the different units and the total cost equals 15 million dollars ($15,000,000) annually and 450 million dollars ($450,000,000) over thirty (30) years. For units K1 through K5, the cost effectiveness of SCR plus combustion control ranges from $1,929 per ton to $4,434 per ton of NO_X emissions in the different units and the total cost equals 14 million dollars ($14,000,000) annually and 420 million dollars ($420,000,000) over thirty (30) years.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress, it is anticipated that these changes could be implemented within three to five years.

4.2.3. Energy and Non-Air Quality Environmental Impacts

SNCR and SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist. SNCR and SCR can potentially cause significant environmental impacts related to the storage of ammonia, and the storage of aqueous ammonia above 10,000 pounds is regulated by the EPA's Risk Management Program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SNCR and SCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SNCR and SCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia. Ammonia released from SNCR and SCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Table 4-4. NO_X Cost effectiveness of Controls Summary

Unit	Control Option	2017 NO_X Emissions [A] (tpy)	Controlled Emission Level [B,C] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_X Emissions (tpy)	NO_X Reduced (ton/yr)	Total Annual Cost [D,E] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	932.7	0.38	3,778,041	718.2	214.5	$4,621,182	$21,542
	ULSD	932.7	0.27	3,778,041	513.0	419.7	$9,814,026	$23,383
	Combustion Controls	932.7	0.30	3,778,041	566.7	366.0	$482,550	$1,318
	SNCR	932.7	0.40	3,778,041	755.6	177.1	$854,332	$4,824
	SNCR+Combustion Controls	932.7	0.20	3,778,041	377.8	554.9	$1,336,882	$2,409
	SCR	932.7	0.10	3,778,041	188.9	743.8	$2,210,698	$2,972
	SCR+Combustion Controls	932.7	0.05	3,778,041	94.5	838.2	$2,693,248	$3,213
K2	Residual Oil/ULSD Blend	963.0	0.50	2,959,869	741.5	221.5	$3,620,420	$16,346
	ULSD	963.0	0.36	2,959,869	529.7	433.4	$7,688,703	$17,742
	Combustion Controls	963.0	0.30	2,959,869	444.0	519.0	$467,426	$901
	SNCR [F]	963.0	0.40	2,959,869	592.0	371.0	$854,332	$2,303
	SNCR+Combustion Controls	963.0	0.20	2,959,869	296.0	667.0	$1,321,758	$1,982
	SCR	963.0	0.10	2,959,869	148.0	815.0	$2,083,950	$2,557
	SCR+Combustion Controls	963.0	0.05	2,959,869	74.0	889.0	$2,551,376	$2,870
K3	Residual Oil/ULSD Blend	661.7	0.32	3,753,356	595.5	66.2	$4,590,989	$69,382
	ULSD	661.7	0.28	3,753,356	529.4	132.3	$9,749,905	$73,673
	Combustion Controls	661.7	0.20	3,753,356	375.3	286.4	$346,310	$1,209
	SNCR	661.7	0.25	3,753,356	469.2	192.5	$789,403	$4,100
	SNCR+Combustion Controls	661.7	0.15	3,753,356	281.5	380.2	$1,135,713	$2,987
	SCR	661.7	0.10	3,753,356	187.7	474.0	$2,171,338	$4,581
	SCR+Combustion Controls	661.7	0.05	3,753,356	93.8	567.9	$2,517,649	$4,434
K4	Residual Oil/ULSD Blend	732.2	0.34	3,858,826	659.0	73.2	$4,719,995	$64,463
	ULSD	732.2	0.30	3,858,826	585.8	146.4	$10,023,877	$68,450
	Combustion Controls	732.2	0.20	3,858,826	385.9	346.3	$349,044	$1,008
	SNCR [F]	732.2	0.25	3,858,826	482.4	249.8	$789,403	$3,160
	SNCR+Combustion Controls	732.2	0.15	3,858,826	289.4	442.8	$1,138,447	$2,571
	SCR	732.2	0.10	3,858,826	192.9	539.3	$2,202,873	$4,085
	SCR+Combustion Controls	732.2	0.05	3,858,826	96.5	635.7	$2,551,917	$4,014
K5	Residual Oil/ULSD Blend	2,044.2	0.62	5,099,323	1,574.0	470.2	$6,237,333	$13,266
	ULSD	2,044.2	0.44	5,099,323	1,124.3	919.9	$13,246,254	$14,400
	Combustion Controls	2,044.2	0.30	5,099,323	764.9	1,279.3	$638,537	$499
	SNCR	2,044.2	0.40	5,099,323	1,019.9	1,024.3	$1,358,582	$1,326
	SNCR+Combustion Controls	2,044.2	0.20	5,099,323	509.9	1,534.3	$1,997,119	$1,302
	SCR	2,044.2	0.10	5,099,323	255.0	1,789.2	$3,058,173	$1,709
	SCR+Combustion Controls	2,044.2	0.05	5,099,323	127.5	1,916.7	$3,696,710	$1,929
K6	Residual Oil/ULSD Blend	630.1	0.16	6,424,644	516.7	113.4	$7,858,425	$69,287
	ULSD	630.1	0.13	6,424,644	403.3	226.8	$16,688,974	$73,573
	SNCR [G]	630.1	0.15	6,424,644	481.8	148.3	$883,819	$5,962
	SCR [G]	630.1	0.05	6,424,644	160.6	469.5	$3,045,798	$6,488

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010. The controlled emission level for the 50/50 residual oil/ULSD blend is based on the average of the AP-42 emission factor for No. 2 fuel oil and the 2017 emission factor.

[C] Controlled emission levels based on "Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler" EPA, 1994.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019 dollars.

[E] See Appendix A for the total annual cost calculations for combustion controls, SNCR and SCR.

[F] The annual cost for K2 is based on K1 which has a similar design and rating and the annual cost for K4 is based on K3 which has a similar design and rating.

[G] K6 is equipped with combustion controls, the level of SCR control was reduced to 0.05 lb/MMBtu to account for the combined level of control.

Table 5-3. PM_{10} Cost Effectiveness Summary

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	55.7	0.0203	3,778,041	38.4	17.3	$4,621,182	$267,631
	ULSD	55.7	0.0112	3,778,041	21.2	34.5	$9,814,026	$284,184
K2	Residual Oil/ULSD Blend	39.3	0.0183	2,959,869	27.1	12.2	$3,620,420	$297,170
	ULSD	39.3	0.0101	2,959,869	14.9	24.4	$7,688,703	$315,550
K3	Residual Oil/ULSD Blend	51.7	0.0190	3,753,356	35.7	16.0	$4,590,989	$286,453
	ULSD	51.7	0.0105	3,753,356	19.6	32.1	$9,749,905	$304,171
K4	Residual Oil/ULSD Blend	50.5	0.0181	3,858,826	34.8	15.7	$4,719,995	$301,501
	ULSD	50.5	0.0099	3,858,826	19.2	31.3	$10,023,877	$320,149
K5	Residual Oil/ULSD Blend	78.7	0.0213	5,099,323	54.3	24.4	$6,237,333	$255,660
	ULSD	78.7	0.0117	5,099,323	29.9	48.8	$13,246,254	$271,473
K6	Residual Oil/ULSD Blend	108.6	0.0233	6,424,644	74.9	33.7	$7,858,425	$233,423
	ULSD	108.6	0.0128	6,424,644	41.3	67.3	$16,688,974	$247,861

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010. The controlled emission level for the 50/50 residual oil/ULSD blend is based on the average of the AP-42 emission factor for No. 2 fuel oil and the 2017 emission factor.

[C] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019 dollars.

Appendix Table A-1. CDS Capital and O&M Cost Estimate

Unit MW Rating (Nominal) Classification	K1 92 Fuel Oil	K2 90 Fuel Oil	K3 92 Fuel Oil	K4 93 Fuel Oil	K5 142 Fuel Oil	K6 142 Fuel Oil
Capital Cost						
Direct Costs						
Total Direct Costs (DC)	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 61,988,000	$ 61,988,000
Indirect Costs						
Summary of Indirect Costs not including Contingency	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 19,142,000	$ 19,142,000
Contingencies	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 21,468,000	$ 21,468,000
Total Indirect Costs (IC)	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 40,610,000	$ 40,610,000
Allowance for Funds Used During Construction (AFDC)	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 10,466,000	$ 10,466,000
Total Capital Investment (TCI)	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 113,064,000**	**$ 113,064,000**
Annual Cost						
Direct Annual Costs						
Fixed Annual Costs						
Maintenance labor and materials	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Total Fixed Annual Costs	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Variable Annual Costs						
Byproduct disposal	$ 273,000	$ 294,000	$ 377,000	$ 314,000	$ 478,000	$ 352,000
Reagent Cost (lime)	$ 632,000	$ 679,000	$ 864,000	$ 740,000	$ 1,582,000	$ 1,204,000
Water Cost	$ 51,000	$ 54,000	$ 69,000	$ 58,000	$ 116,000	$ 88,000
Power (ID and Aux) Cost	$ 1,561,000	$ 1,675,000	$ 2,151,000	$ 1,805,000	$ 4,259,000	$ 3,161,000
Total Variable Annual Costs	$ 2,517,000	$ 2,702,000	$ 3,461,000	$ 2,917,000	$ 6,435,000	$ 4,805,000
Total Direct Annual Costs (DAC)	$ 4,305,000	$ 4,490,000	$ 5,249,000	$ 4,705,000	$ 8,878,000	$ 7,248,000
Indirect Annual Costs						
Cost for capital recovery [2]	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 9,111,421	$ 9,111,421
Total Indirect Annual Costs (IDAC)	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 9,111,421	$ 9,111,421
Total Annual Cost (TAC) - 2012 Dollars	**$ 10,208,196**	**$ 10,393,196**	**$ 11,152,196**	**$ 10,608,196**	**$ 17,989,421**	**$ 16,359,421**
Total Annual Cost (TAC) - 2019 Dollars [3]	**$ 10,608,072**	**$ 10,800,319**	**$ 11,589,051**	**$ 11,023,741**	**$ 18,694,104**	**$ 17,000,254**

[1] Costing from an Hawaiian Electric internal study dated July 2012.

[2] Capital Recovery Factor (CRF) = [I x (1+i)^a]/[(1+i)^a - 1]   CRF = 0.08

Where:

I = Interest Rate (7% interest)

a = Equipment life (30 yrs)

[3] Cost scaled to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI) for 2012 (584.6) and 2019 (607.5). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

Appendix Table A-2. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	K1	K2	K3	K4	K5
Boiler design capacity, mmBtu/hr (C)		903	900	892	918	1468
Boiler Type		Normal	Normal	Tangential	Tangential	Normal
2017 Annual Heat Input, MMBtu/yr (H)		3,778,041	2,959,869	3,753,356	3,858,826	5,099,323
Unit Size, kW (kW)		92,000	90,000	92,000	93,000	142,000
Unit Size, MW (MW)		92.0	90.0	92.0	93.0	142.0
Capital recovery factor a. Equipment CRF, 30-yr life, 7% interest	= [I x (1+i)^a]/[(1+i)^a - 1] where I = interest rate, a = equipment life	0.08	0.08	0.08	0.08	0.08
Cost Index (CI) [A] a. 2019 b. 2004	 607.5 444.2					
Total Capital Investment [B,C] TCI ($)	=$24/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall =$18/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$4,615,869	$4,551,295	$3,461,902	$3,485,976	$6,096,525
Direct Annual Operating Costs $/yr Variable O&M Costs [D]	=($0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Wall $0.03 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Tangential	$41,336	$32,384	$15,400	$15,832	$55,792
Indirect Annual Costs, $/yr 1. Fixed O&M Costs [E]	= $0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall = $0.27/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$69,238	$68,269	$51,929	$52,290	$91,448
2. Capital recovery	= Equipment CRF x TCI	$371,976	$366,772	$278,982	$280,922	$491,297
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$482,550**	**$467,426**	**$346,310**	**$349,044**	**$638,537**

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region,* dated September 6, 2005. The cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

[A] Cost Index: Chemical Engineering Plant Cost Index (CEPCI). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

[B] TCI for LNB and LNB w/over fire air ranges from $6/kW to $24/kW for wall boilers and $10/kW to $18/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO_X control.

[C] Scaling factor = (300/Nameplate capacity)^0.359

[D] The variable O&M costs for LNB and LNB w/over fire air ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr for wall boilers and 0.027 mills/kW-hr to 0.03 mills/kW-hr for tangential boilers, the high end of the range was used due to Hawai'i's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO_X control.

[E] The fixed O&M costs for LNB and LNB w/over fire air ranges from $0.09/kW to $0.36/kW for wall boilers and $0.15/kW to $0.27/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location.

Attachment Table A-3a. Kahe K1 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	384,917	MWhs
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Plant Elevation: 10 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Attachment Table A-3a. Kahe K1 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.494 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.00 Percent		
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*		* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh		
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Attachment Table A-3a. Kahe K1 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Attachment Table A-3a. Kahe K1 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		384,917	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.478	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	355.55	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	743.80	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	418,214	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	111.61	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,746.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	436	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Attachment Table A-3a. Kahe K1 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	501	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.4	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	138	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	476	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	64	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	45,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	511.08	kW

Attachment Table A-3a. Kahe K1 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,543,429	in 2019 dollars

Attachment Table A-3a. Kahe K1 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$793,017	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,417,681	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,210,698	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,717	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$78,028	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,069	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$88,203	in 2019 dollars
Direct Annual Cost =		$793,017	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,681	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,414,000	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,417,681	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,210,698	per year in 2019 dollars
NOx Removed =	744	tons/year
Cost Effectiveness =	$2,972	per ton of NOx removed in 2019 dollars

Appendix Table A-3b. Kahe K2 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	90	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	295,987	MWhs
Enter the net plant heat input rate (NPHR)	10.0000	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

Appendix Table A-3b. Kahe K2 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.651	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3b. Kahe K2 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	900	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	788,400	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		295,987	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.375	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3289	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	84.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	495.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	815.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	416,824	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	101.67	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,099.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	434	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	499	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.3	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	193	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	664	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	89	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	63,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	504.00	kW

Appendix Table A-3b. Kahe K2 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,294,581	in 2019 dollars

Appendix Table A-3b. Kahe K2 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$686,341 in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,397,609 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,083,950 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$86,473 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$85,498 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$417,862 in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$96,508 in 2019 dollars
Direct Annual Cost =		$686,341 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,666 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,393,943 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,397,609 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,083,950 per year in 2019 dollars
NOx Removed =	815 tons/year
Cost Effectiveness =	$2,557 per ton of NOx removed in 2019 dollars

Appendix Table A-3c. Kahe K3 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	387,117	MWhs
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

Appendix Table A-3c. Kahe K3 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.353 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life * For utility boilers, the typical equipment life of an SCR is at least 30 years.	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 \$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 \$/kWh	
Catalyst cost ($CC_{replace}$)	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 \$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3c. Kahe K3 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		387,117	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	71.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	225.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	474.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.90		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	413,119	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	126.44	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,267.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	430	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	495	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	302	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	508.40	kW

Appendix Table A-3c. Kahe K3 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,543,429	in 2019 dollars

Appendix Table A-3c. Kahe K3 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$753,657	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,417,681	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,171,338	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,717	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$49,728	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,302	in 2019 dollars
Annual Catalyst Replacement Cost =		$76,910	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$753,657	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,681	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,414,000	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,417,681	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,171,338	per year in 2019 dollars
NOx Removed =	474	tons/year
Cost Effectiveness =	$4,581	per ton of NOx removed in 2019 dollars

Appendix Table A-3d. Kahe K4 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	93	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	390,927	MWhs
Enter the net plant heat input rate (NPHR)	9.8710	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- (selected) Not applicable

Appendix Table A-3d. Kahe K4 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.379 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30 days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	541.7 2016 CEPCI — CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3d. Kahe K4 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	918	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	814,680	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		390,927	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.99		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4204	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	73.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	256.58	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	539.26	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.92		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	425,161	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	122.82	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,461.60	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	443	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	509	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	100	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	344	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	46	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	33,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = Bmw for utility boilers	517.90	kW

Appendix Table A-3d. Kahe K4 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,667,143	in 2019 dollars

Appendix Table A-3d. Kahe K4 - SCR Costing

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$775,213	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,427,660	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,202,873	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$88,336	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$56,571	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$548,821	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$81,486	in 2019 dollars
Direct Annual Cost =		$775,213	in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,688	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,423,972	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,427,660	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,202,873	per year in 2019 dollars
NOx Removed =	539	tons/year
Cost Effectiveness =	$4,085	per ton of NOx removed in 2019 dollars

Appendix Table A-3e. Kahe K5 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	493,259	MWhs
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ( ) Method 1
- ( ) Method 2
- (•) Not applicable

Appendix Table A-3e. Kahe K5 - SCR Costing

Enter the following design parameters for the proposed SCR:

Parameter	Value	Unit
Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.802	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Parameter	Value	Unit
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Parameter	Value	Unit
Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Unit	Notes
Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3e. Kahe K5 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		493,259	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.397	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	87.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1030.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,789.23	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.09		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	679,886	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	94.77	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,173.70	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	708	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	814	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	28.5	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	400	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,381	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	184	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	132,800	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	806.65	kW

Appendix Table A-3e. Kahe K5 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$23,261,613	in 2019 dollars

Appendix Table A-3e. Kahe K5 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,179,264	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,878,910	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,058,173	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$116,308	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$187,699	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$706,389	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$168,868	in 2019 dollars
Direct Annual Cost =		$1,179,264	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,024	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,874,886	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,878,910	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,058,173	per year in 2019 dollars
NOx Removed =	1,789	tons/year
Cost Effectiveness =	$1,709	per ton of NOx removed in 2019 dollars

Appendix Table A-3f. Kahe K6 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	601,781	MWhs
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Plant Elevation: 10 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Appendix Table A-3f. Kahe K6 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.196	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	\$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	\$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Appendix Table A-3f. Kahe K6 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		601,781	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.484	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	74.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	221.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	469.48	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.93		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	702,117	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	129.61	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,417.25	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	731	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	841	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	29.0	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	86	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	297	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	28,600	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	817.89	kW

Appendix Table A-3f. Kahe K6 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$23,261,613	in 2019 dollars

Appendix Table A-3f. Kahe K6 - SCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,166,888 in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,878,910 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,045,798 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$116,308 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$49,251 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$873,807 in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$127,521 in 2019 dollars
Direct Annual Cost =		$1,166,888 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,024 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,874,886 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,878,910 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,045,798 per year in 2019 dollars
NOx Removed =	469 tons/year
Cost Effectiveness =	$6,488 per ton of NOx removed in 2019 dollars

Appendix Table A-4a. Kahe K1 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	384,917	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Appendix Table A-4a. Kahe K1 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days	Plant Elevation	10	Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.494	lb/MMBtu			
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.4	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	1.22				
Concentration of reagent as stored (C_{stored})	29	Percent			
Density of reagent as stored (ρ_{stored})	56	lb/ft^3			
Concentration of reagent injected (C_{inj})	10	percent			
Number of days reagent is stored ($t_{storage}$)	14	days			
Estimated equipment life	20	Years			
Select the reagent used	Ammonia				

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

Appendix Table A-4a. Kahe K1 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-4a. Kahe K1 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		384,917	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	19	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	84.65	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	177.09	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Appendix Table A-4a. Kahe K1 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	201	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	694	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	92.7	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	31,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	26.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	158	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent} \times ((1/C_{inj})-1)$ =	1.63	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1\text{x}10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Appendix Table A-4a. Kahe K1 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,639,022	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,714,103	in 2019 dollars
Total Capital Investment (TCI) =	$5,659,063	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,639,022	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Appendix Table A-4a. Kahe K1 - SNCR Costing

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,714,103	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$317,570	in 2019 dollars
Indirect Annual Costs (IDAC) =	$536,762	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$854,332	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$84,886	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$113,686	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$27,473	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$2,758	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$88,768	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0	in 2019 dollars
Direct Annual Cost =		$317,570	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,547	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$534,216	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$536,762	in 2019 dollars

Appendix Table A-4a. Kahe K1 - SNCR Costing

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$854,332	per year in 2019 dollars
NOx Removed =	177	tons/year
Cost Effectiveness =	$4,824	per ton of NOx removed in 2019 dollars

Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	387,117	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Appendix Table A-4b. Kahe K3 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.353	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.25	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-4b. Kahe K3 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		387,117	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	29	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	91.51	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	192.53	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Appendix Table A-4b. Kahe K3 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	142	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	490	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	65.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	22,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	18.6	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	112	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.15	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Appendix Table A-4b. Kahe K3 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,630,607	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,739,588	in 2019 dollars
Total Capital Investment (TCI) =	$5,681,253	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,630,607	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Appendix Table A-4b. Kahe K3 - SNCR Costing

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	$2,739,588 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$250,536 in 2019 dollars
Indirect Annual Costs (IDAC) =	$538,867 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$789,403 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$85,219 in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$80,654 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$19,731 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$1,956 in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$62,976 in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0 in 2019 dollars
Direct Annual Cost =		$250,536 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,557 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$536,310 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$538,867 in 2019 dollars

Appendix Table A-4b. Kahe K3 - SNCR Costing

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$789,403	per year in 2019 dollars
NOx Removed =	193	tons/year
Cost Effectiveness =	$4,100	per ton of NOx removed in 2019 dollars

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	493,259	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Appendix Table A-4c. Kahe K5 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.802	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.40	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI		CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent		
Fuel ($Cost_{fuel}$)	13.01	\$/MMBtu		Actual Data Used
Reagent ($Cost_{reag}$)	0.293	\$/gallon for a 29 percent solution of ammonia		Default Value Used
Water ($Cost_{water}$)	0.0042	\$/gallon		Default Value Used
Electricity ($Cost_{elect}$)	0.2521	\$/kWh		Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-4c. Kahe K5 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		493,259	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.40	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	50	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	589.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,024.34	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Appendix Table A-4c. Kahe K5 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	531	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,833	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	244.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	82,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	65.3	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	417	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	4.31	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1 \times 10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Appendix Table A-4c. Kahe K5 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,010,115	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,953,628	in 2019 dollars
Total Capital Investment (TCI) =	$7,752,866	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$2,010,115	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Appendix Table A-4c. Kahe K5 - SNCR Costing

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$3,953,628 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$623,223 in 2019 dollars
Indirect Annual Costs (IDAC) =	$735,359 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,358,582 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$116,293 in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$249,165 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$57,167 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$6,044 in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$194,553 in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0 in 2019 dollars
Direct Annual Cost =		$623,223 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,489 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$731,871 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$735,359 in 2019 dollars

Appendix Table A-4c. Kahe K5 - SNCR Costing

Cost Effectiveness
Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,358,582	per year in 2019 dollars
NOx Removed =	1,024	tons/year
Cost Effectiveness =	$1,326	per ton of NOx removed in 2019 dollars

Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	601,781	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Appendix Table A-4d. Kahe K6 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days	Plant Elevation	10 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.196	lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	1.22			
Concentration of reagent as stored (C_{stored})	29	Percent		
Density of reagent as stored (ρ_{stored})	56	lb/ft^3		
Concentration of reagent injected (C_{inj})	10	percent		
Number of days reagent is stored ($t_{storage}$)	14	days		
Estimated equipment life	20	Years		
Select the reagent used	Ammonia			

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Appendix Table A-4d. Kahe K6 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		601,781	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	24	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	69.96	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	148.25	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Appendix Table A-4d. Kahe K6 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	134	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	463	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	61.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	20,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	16.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	105	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.09	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,037,463	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,061,252	in 2019 dollars
Total Capital Investment (TCI) =	$6,628,329	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$2,037,463	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Appendix Table A-4d. Kahe K6 - SNCR Costing

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$3,061,252 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$255,122 in 2019 dollars
Indirect Annual Costs (IDAC) =	$628,697 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$883,819 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$99,425 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$76,802 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$17,063 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,863 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$59,969 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2019 dollars
Direct Annual Cost =		$255,122 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,983 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$625,714 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$628,697 in 2019 dollars

Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$883,819	per year in 2019 dollars
NOx Removed =	148	tons/year
Cost Effectiveness =	$5,962	per ton of NOx removed in 2019 dollars

APPENDIX B: HAWAIIAN ELECTRIC REGIONAL HAZE VISIBILITY CONSIDERATIONS

Appendix B:
Hawaiian Electric Regional Haze Visibility Considerations

Fifth Factor Considerations for SO_2 ,NOx, and PM Controls

AECOM Project Number: 60626547

Prepared for:

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September 14, 2020

Hawaiian Electric[1] Regional Haze Visibility Considerations

Fifth Factor Considerations for SO_2, NOx and PM Controls

1. Executive Summary

The EPA has issued multiple guidance documents to assist states and facilities address the requirements of the Regional Haze Rule ("RHR"). This guidance allows states to consider, as part of their review of the Four Factor evaluation of possible emission controls for the Second Decadal Review, a "5th factor" which involves consideration of visibility impacts of candidate control options. This appendix introduces several Hawaiʻi-specific issues that impact the visibility impact of potential sulfur dioxide ("SO_2"), nitrogen oxides ("NOx") and particulate ("PM") control options for Hawaiian Electric sources relative to the two Class 1 areas in Hawaiʻi: the Haleakalā National Park on the island of Maui and the Hawaiʻi Volcanoes National Park on Hawaiʻi Island. The issues discussed in this report are summarized below:

1) Due to unique atmospheric chemistry, NOx emissions tend to remain in the gaseous (and invisible) phase in warm weather, and only form visible NO_3 ("nitrate") particulate aerosol in cold weather. This is verified by monitoring data in the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network in the two national parks mentioned above.

2) The persistent East North East ("ENE") trade winds experienced by the state of Hawaiʻi places emission sources on several islands (or portions of islands such as Maui) downwind of the national parks, limiting the likelihood that any emissions from these sources would even reach the parks. Modeling conducted with the California Puff Model ("CALPUFF") for the First Decadal Review confirms the minimal potential for haze impact of the subject Hawaiian Electric sources on the islands of Oʻahu and Maui due to the predominance of the trade winds. The EPA's Federal Implementation Plan ("FIP") issued in 2012 agreed with this assessment.

3) EPA previously determined that in Hawai´i haze due to direct PM was a very small component of haze and that further controls would not be effective in improving visibility. The observed haze speciation is reviewed in this report to confirm this determination.

4) The State of Hawaiʻi Department of Health Clean Air Branch ("DOH") should request that the EPA (consistent with their first decadal review approach) set aside NOx and PM from the list of haze precursors for Hawaiʻi due to the unique NOx haze chemistry and climate, leaving SO_2 as

[1] "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawaiʻi Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawaiʻi Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

the primary precursor pollutant for haze. Hawaiian Electric requests that the DOH make this proposal to the EPA.

5) In the recent past, volcanic activity on Hawaiʻi Island has produced as much as 2 million tons of SO_2 emissions per year[2,3] (emissions vary yearly and have decreased significantly since September 2018). Additionally, the volcanic activity, although the volcano eruption ended in September 2018, has contributed significant NOx emissions in the past[4]. These historic volcanic SO_2 emissions are about three orders of magnitude (approximately 1,000 times) greater than anthropogenic SO_2 emissions. Although the IMPROVE monitors indicate that sulfate haze is the most important haze species, it is evident from monthly haze trends and the likelihood of winds from the volcanic activity reaching the IMPROVE monitors that the overwhelming historic sulfate haze influence comes from natural sources (i.e., volcanic activity).

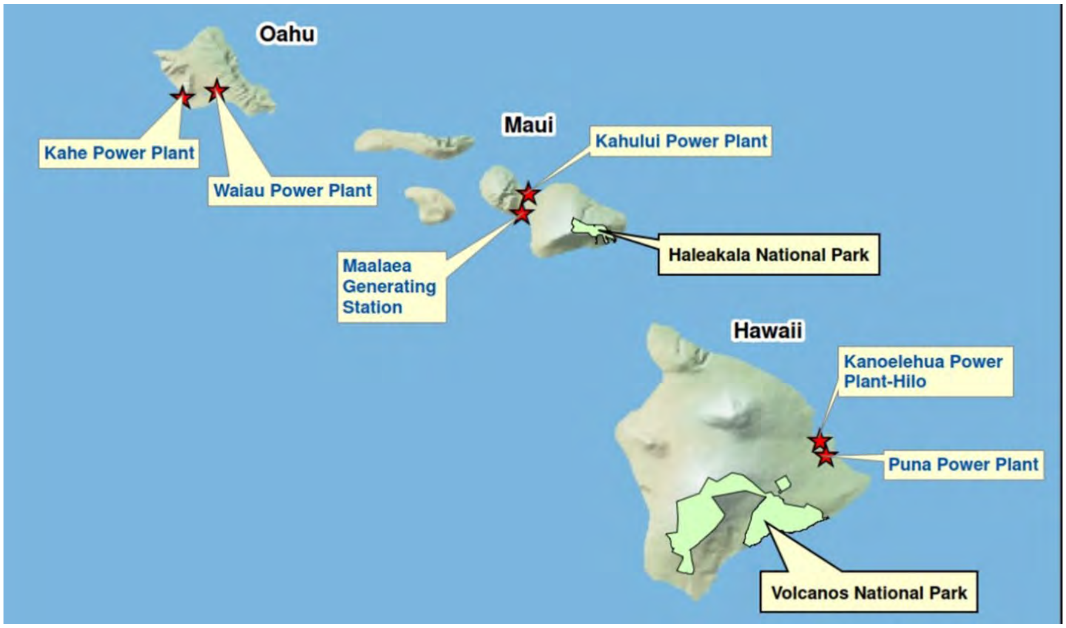
The locations of the affected Hawaiian Electric sources and the two national parks are shown in Figure B-1. The remainder of this appendix presents details of the above issues and recommendations for how this information should be considered in selection of facilities for Four-Factor analyses and for evaluating potential pollutant control options.

[2] Information on the volcanic SO_2 emissions in 2014 was provided by the EPA in their SO_2 National Ambient Air Quality Technical Support Document at EPA's 2016 SO_2 NAAQS TSD, at https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.

[3] Information on 2014-2017 volcanic SO_2 emissions is available in this journal article: Elias T, Kern C, Horton KA, Sutton AJ and Garbeil H. (2018) Measuring SO_2 Emission Rates at Kīlauea Volcano, Hawaii, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full.

[4] The NOx emissions from Hawaiʻi Island volcanic activity is unknown, but could have historically been as high as 25,000 tons per year if the NOx emissions rate equals 6% of SO_2 emissions rate. The 6% is derived from worldwide volcanic NOx emissions estimate of 1.0 Teragram ("Tg" – trillion grams)/year ("yr") nitric oxide ("NO") (or 1.5 Tg/yr NO2) from https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article and worldwide volcanic SO2 estimate of 23 Tg/yr from https://www.nature.com/articles/srep44095.

Figure B-1:
Location of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas



2. EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"[5] in August 2019. This guidance allows states to consider, as part of its consideration of emission controls to include for the Second Decadal Review a "5th factor" which involves consideration of visibility impacts of candidate control options. A companion document[6] issued in September 2019 that involves the EPA's visibility modeling results for 2028 is entitled, "Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling".

On Page 11 of the August 2019 guidance, the EPA states:

> *"When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors."* . . .

[5] Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[6] Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

"Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants"

Further, on Page 36 and 37, the EPA states:

"Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal." . . .

". . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."

Consequently, the extremely low likelihood for impact to Class I visibility impairment from control of certain facility pollutants and the plant locations relative to the Class I areas is appropriate for consideration when evaluating the need for further control of these emissions for Regional Haze Reasonable Progress.

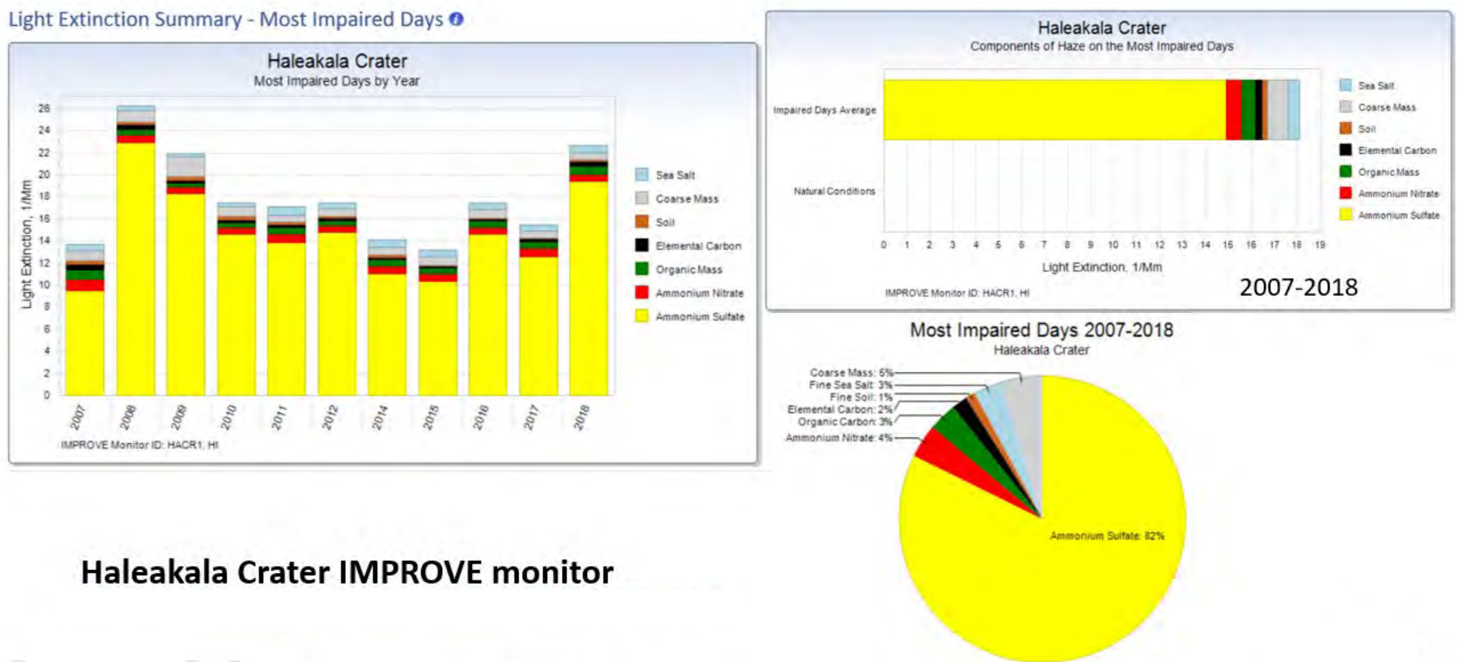
3. Nitrate Haze Composition Analysis

Nitrate haze composition analyses for the Haleakalā and Hawaiʻi Volcanoes National Parks are available at the IMPROVE web site at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/. Figure B-2 provides various charts for the haze species composition at the Haleakalā Crater IMPROVE site, and Figure B-3 provides a time series of stacked bars by species for a recent year at that site. Figures B-4 and B-5 provide similar information for the Hawaiʻi Volcanoes IMPROVE site. Note that these figures show information for the worst 20 percent ("%") impaired days, which is the focus of the RHR for reducing haze. The goal for each decadal review is to track the progress of haze reduction for the worst 20% impaired days; reviewing the composition of haze on these days is a key element in understanding what precursor pollutants to control to achieve the goal.

The data for both National Parks shows that the contribution of nitrates to haze is very low as a percentage of the total, but it is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter ("Mm^{-1}"), equivalent to approximately 0.25 deciview ("dv"), or less. This is the impairment at these monitors due to ALL sources, natural and anthropogenic.

The minimal impact of nitrate haze is clearly illustrated in the Hawaiʻi National Park monitoring data and is much smaller than found at many monitors in other Class 1 areas around the country. This is in large part due to the unique chemistry of nitrate haze, as discussed below.

Figure B-2: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Haleakalā Crater IMPROVE Site



Data source for Figures B-2 through B-5: http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum.

Figure B-3: Time Series of 2018 Daily Haze Extinction Composition Plots for the Haleakalā Crater IMPROVE Site

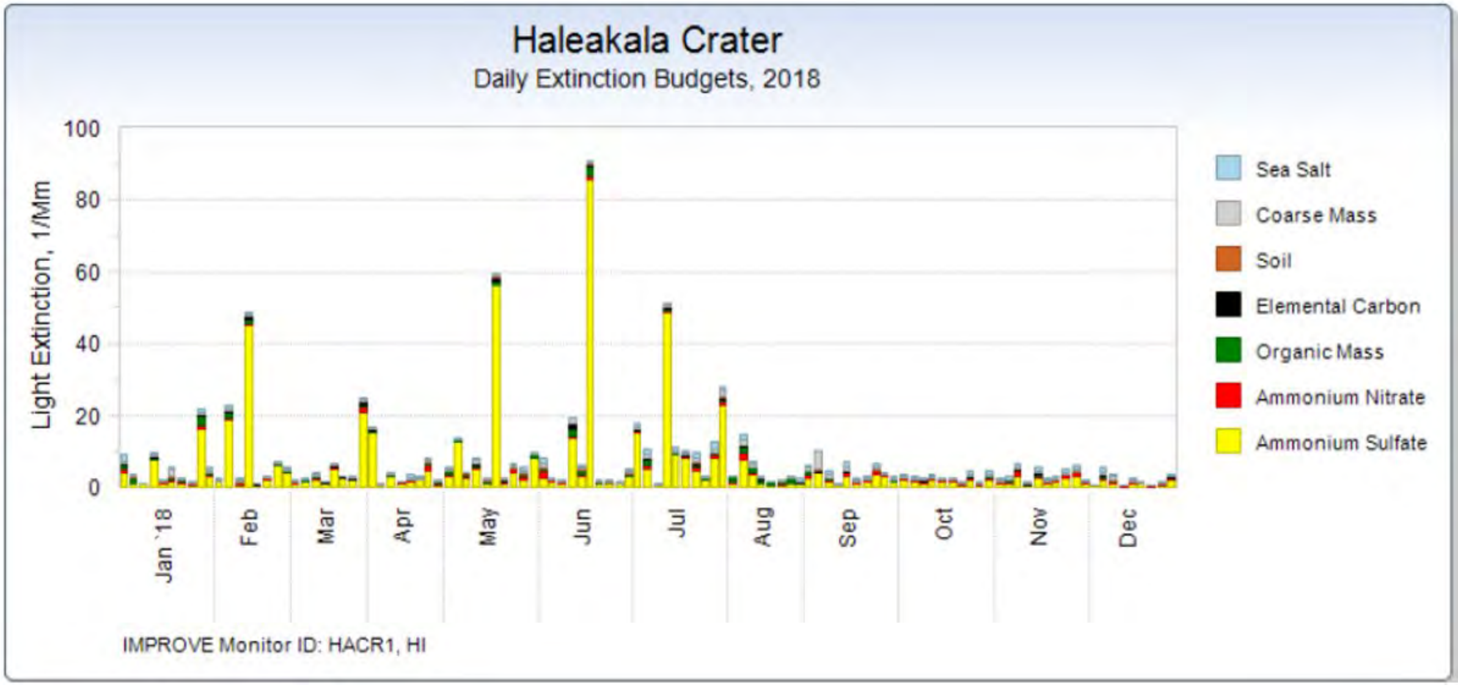


Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site

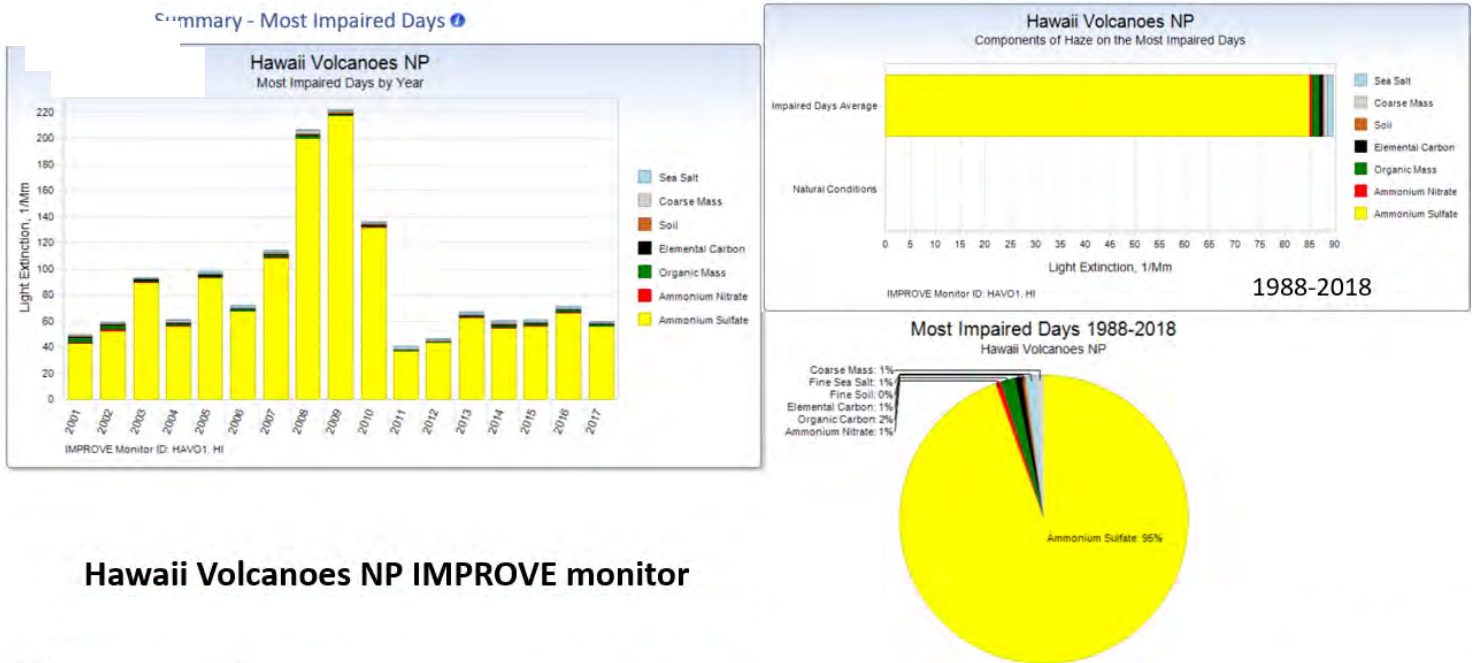
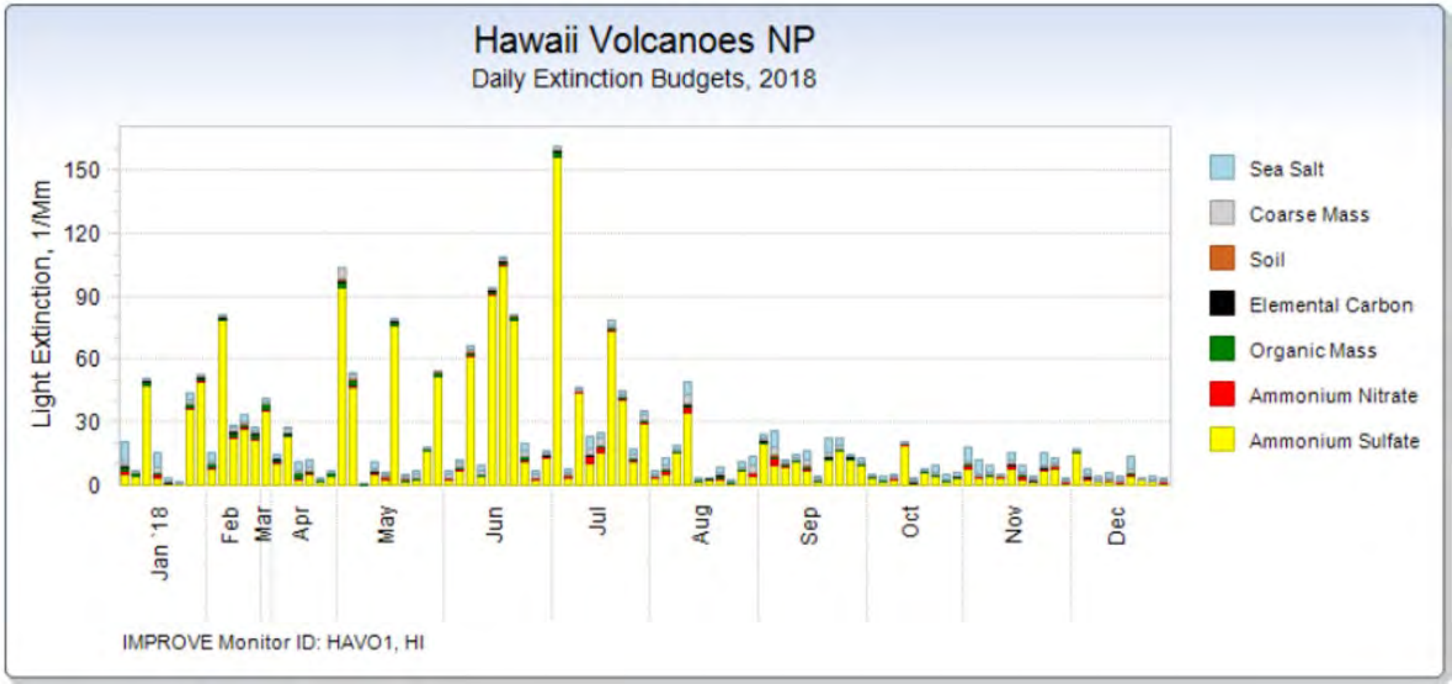
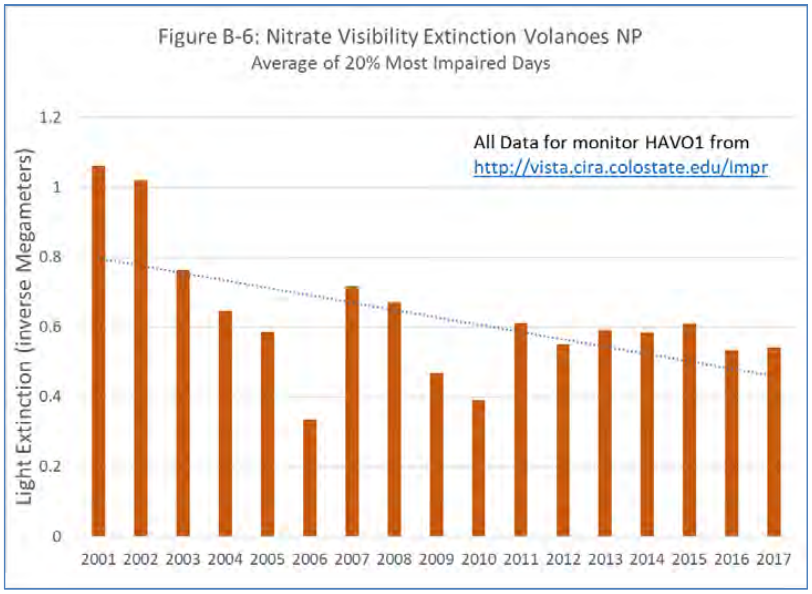
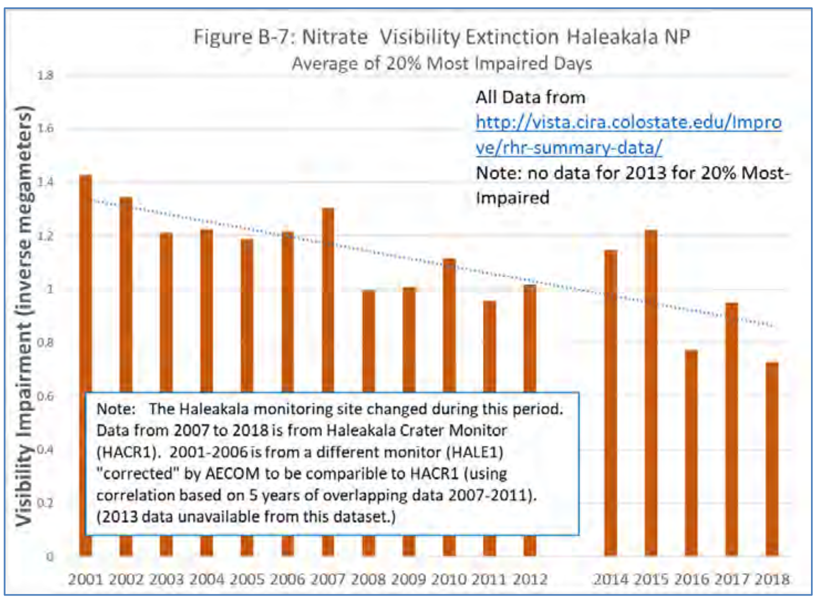


Figure B-5: Time Series of 2018 Daily Haze Extinction Composition Plots for the Hawai'i Volcanoes IMPROVE Site



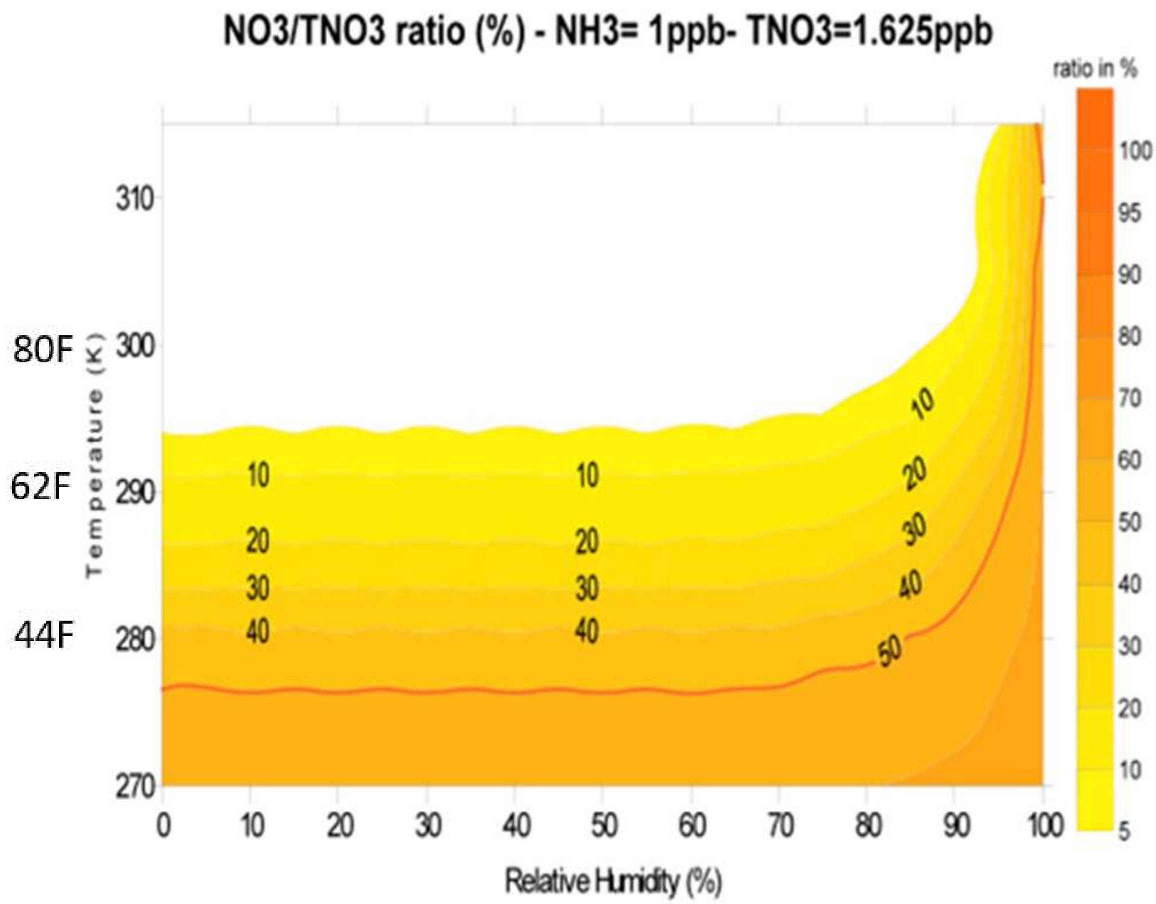
The nitrate contribution to visibility impairment in the above bar charts is shown as a narrow "red" segment. The small size relative to other constituents clearly shows that nitrate is only a small contributor. Additionally, the Figures B-6 and B-7 below which presents only the ammonium nitrate visibility impairment also shows that nitrates, already small contribution, is trending downward.





The chemistry of nitrate haze formation is highly dependent upon ambient temperature, and to a lesser extent upon humidity. As discussed in the CALPUFF model formulation[7] and in CALPUFF courses, total nitrate in the atmosphere ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous nitric acid ("HNO_3") (invisible, and not haze-producing) and nitrate ("NO_3") haze particles according to the equilibrium relationship between the two species, which is affected by temperature and humidity.

Figure B-8: CALPUFF Example Plot of Aerosol Percentage of Total NOx Equilibrium



The potential for the formation of haze due to NOx emissions is very low in Hawai'i because of the warm weather conditions year-round. This strong dependency of the equilibrium relationship between invisible gaseous HNO_3 and visible NO_3 haze particles as a function of ambient temperature is illustrated in Figure B-8. In Figure B-8, it is evident that for most conditions, the percentage of total nitrate in the form of particulate (NO_3) is less than 20% for temperatures above approximately 286 degrees Kelvin (approximately 55 degrees Fahrenheit). Temperatures at most locations in Hawai'i rarely get that low and are not that low at any of the Hawaiian Electric plant locations.

[7] Documentation for the CALPUFF modeling system is available from links provided at https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff.

This dependency of nitrate haze formation as a function of temperature (and season) for more seasonally-varying locations in the United States is shown in the September 2019 EPA modeling report[2] in Figure B-9 (from Appendix A of that report). This figure shows that the thermodynamics of the nitrate haze equilibrium result in much greater particulate formation in winter versus other seasons for more temperate climates, while NOx emissions are expected to be relatively constant over the entire year. This implies that NOx emission reductions would only be effective for haze reduction during cold winter months, while consideration of NOx emission reductions in other months is relatively ineffective.

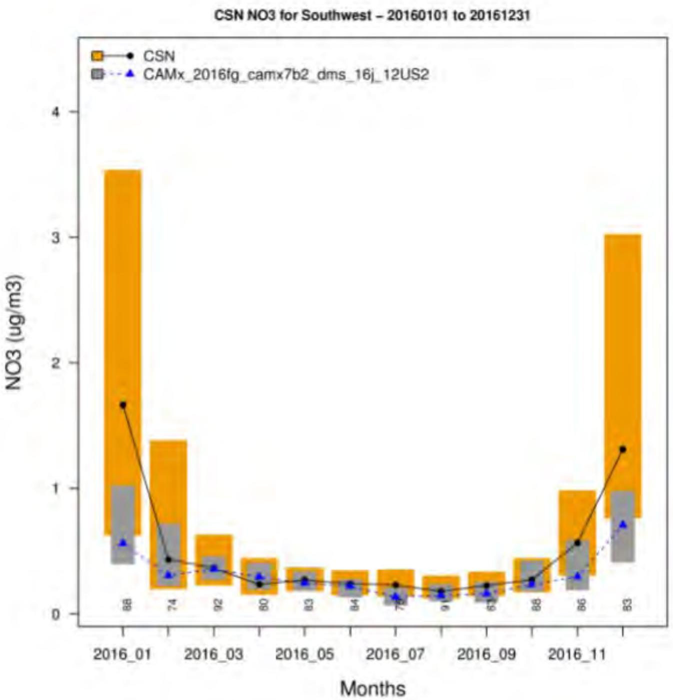
It should also be noted that volcanic activity on Hawaiʻi Island may also be a large source of NOx in the state. Volcanoes are commonly thought of as large sources of SO_2, but they also can emit significant amounts of NOx. Laboratory analysis[8] of NOx emissions content in volcanic exhaust indicates a substantial component, likely caused by thermal contact of air with lava. The annual worldwide volcano NOx emissions (as NO_2) is estimated[3] at approximately 1.5 teragrams ("Tg" – trillion grams).

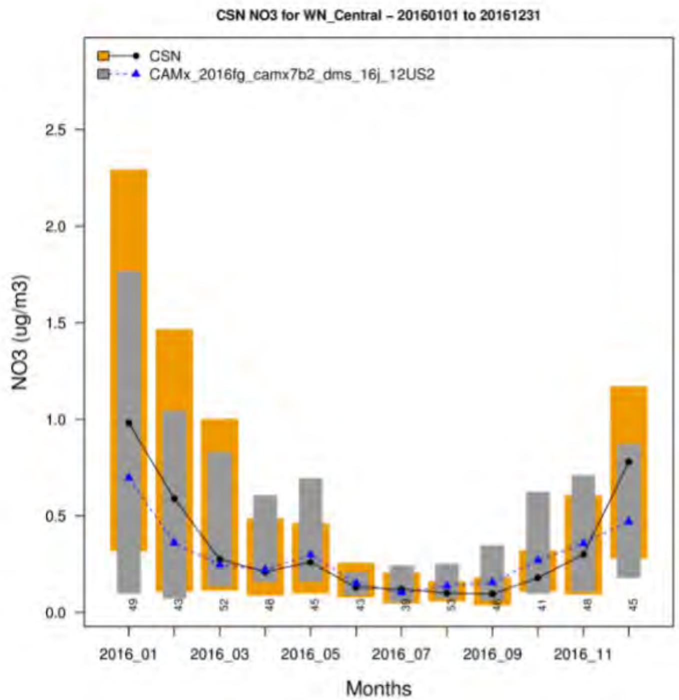
In summary, nitrate haze is a very small component in Hawaiʻi's Class I areas, which is expected given nitrate chemistry and is verified by the IMPROVE monitoring data. The mulitple-year average of the nitrate haze impact for worst 20% days at the two areas is approximately Mm-1, or less than 0.5 delta-dv. This total nitrate haze impact is less than the de minimis contribution threshold used to eliminate a single source from consideration for controls during the First Decadal Review period.

Due to the low haze impact of NOx (even if every source in the state and the volcano was eliminated), the state of Hawaiʻi should limit the haze precursors control evaluations to SO_2 for the Second Decadal Review. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NOx controls to be material. The State of Hawaiʻi Department of Health should work with the EPA to provide this technical justification to remove NOx as a haze precursor for the state of Hawaiʻi.

[8] Mather, T., 2004. A Volcanic Breath of Life? Chemistry World, 30 November 2004 Featured Article. https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article.

Figure B-9: Monthly Variation of Nitrate Particulate Concentrations for Selected IMPROVE Sites from EPA 2019 Modeling Report





4. PM Species Haze Composition Analysis

In their Federal Implementation Plan Technical Support Document[9], EPA noted that "due to the overwhelming contribution of sulfate to visibility impairment at the nearby Hawaii Volcanoes Class I area, it is unlikely that reductions in these pollutants [NOx and PM]…would have a measurable impact on visibility at that area."

It is clear from a review of the haze speciation shown in Figures B-2 through B-5 that the contribution to haze of direct particulate species such as elemental carbon, soil, and coarse mass is relatively low. Furthermore, emissions of coarse PM mass (ash) from the volcanic activity can be very high (clearly evident from photos of volcanic activity) to the extent that it may result in aviation alerts. These emissions can be much greater than emissions from power plants and can constitute a significant portion of the direct PM-caused haze shown in Figures B-2 through B-5. The remaining human-caused haze due to direct PM emissions is therefore a very small component of the total haze, and this determination is consistent with EPA's 2012 assessment.

5. Predominant Trade Winds in Hawaiʻi

The EPA's FIP for Hawaiʻi for the First Decadal Review (77 FR 61478, October 9, 2012) acknowledged the direction of the predominant trade winds in Hawaiʻi and thus did not require controls on upwind sources (i.e., sources on Oʻahu and Maui). Figure B-10 shows the locations of the Hawaiian Electric sources and the national parks, along with wind rose plots for airports on Maui and Oʻahu. The wind rose plots show that the wind is almost always from the northeast and rarely blows from the Hawaiian Electric facilities on Oʻahu or Maui toward either of Hawaiʻi's Class 1 areas.

The EPA CALPUFF modeling conducted for the First Decadal Review confirms the expected low impacts from sources on Maui, even though the sources were relatively close to Haleakalā National Park. This result is due to the fact, as stated above, that winds rarely blow the emissions from sources downwind from the parks back to the parks, and the CALPUFF modeling confirmed the low impact from occasional periods when the wind may blow toward the parks from the sources modeled. The Western Regional Air Partnership ("WRAP") Q/d analysis that included several sources on the islands of Oʻahu and Maui in the four-factor analysis did not consider the wind patterns. A review of past modeling and the EPA's 2012 FIP should lead to a dismissal of those sources from inclusion in four-factor analyses for the second decadal review period.

The geometry and wind roses shown in Figure B-10 and previous CALPUFF modeling both indicate that Hawaiian Electric generating stations on Oʻahu and Maui would have minimal impact to Class 1 area haze. Because of this, and the minimal impact of NOx due to nitrate chemistry, consideration of

[9] EPA, May 14, 2012. Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii. EPA docket EPA-R09-OAR-2012-0345-0002 via www.regulations.gov.

potential additional pollution controls at Hawaiian Electric facilities for Regional Haze progress should be limited to SO_2 for sources on Hawaiʻi Island.

6. Natural Sources of SO_2 From Volcanic Activity

Volcanic activity on the Hawaiʻi Island represents a unique and challenging complication to understanding haze in Hawaiʻi Class I areas. The Kilauea volcano on Hawaiʻi Island has been active for several years, and the levels of SO_2 emissions are being monitored by the United States Geological Survey. As shown in Figure B-11[10] (related to the SO_2 National Ambient Air Quality Standards implementation and monitoring), there were over 2 million tons of SO_2 emissions from volcanic activity on Hawaiʻi Island in the year 2014, compared to roughly 2,000 tons of power plant SO_2 emissions for that year. As noted in a *Frontiers in Earth Science* 2018 article[11], the volcanic SO_2 emissions have been relatively steady at levels close to 2 million TPY for the period of 2014 to 2017. The volcanic SO_2 emissions have decreased after the Kilauea eruption ended in September 2018, but remain significant. The USGS preliminary estimates of annual volcanic emissions of SO_2 for 2019 are 17,119 tons/year[12].

The extremely high and variable levels of natural SO_2 emissions present a significant challenge for defining “impaired” haze days because the same pollutant (i.e., SO_2) is emitted by volcanic activity and the power plants and other combustion sources. Therefore, the RHR glidepath for the two Class I areas in Hawaiʻi is difficult to establish if naturally-caused haze is to be excluded from the analysis.

There appears to be very little anthropogenic haze impairment remaining at Haleakalā National Park because there are very few sources on Maui upwind of the park and there are no land masses upwind of Maui for thousands of kilometers. For Hawaiʻi Island, the largest sources of SO_2 are natural sources that are part of (or adjacent to) the park.

Even the anthropogenic sources (from power plants) are projected to be phased out well before the end point of the RHR (i.e., 2064) by Hawaiʻi’s State Renewable Portfolio Standards Law (“RPS”) implementing requirements to convert 100% of the state’s electrical generation to renewable energy sources. This RPS law (Hawaiʻi Revised Statute §269-92) will substantially reduce emissions of haze precursors by 2045. Further details of the past and future benefits of the RPS requirements are detailed in separate Appendix C.

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[10] https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.
[11] Elias, T., C. Kern, K. Horton, A. Sutton, and H. Garbeil, 2018. Measuring SO_2 Emission Rates at Kīlauea Volcano, Hawaiʻi, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci*. 6:214. doi: 10.3389/feart.2018.00214. https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full.
[12] Hawaii Dept. of Health comment letter to Hawaiian Electric Light Company regarding Puna Generating Station Four Factor Analysis; July 8, 2020.

Figure B-10: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

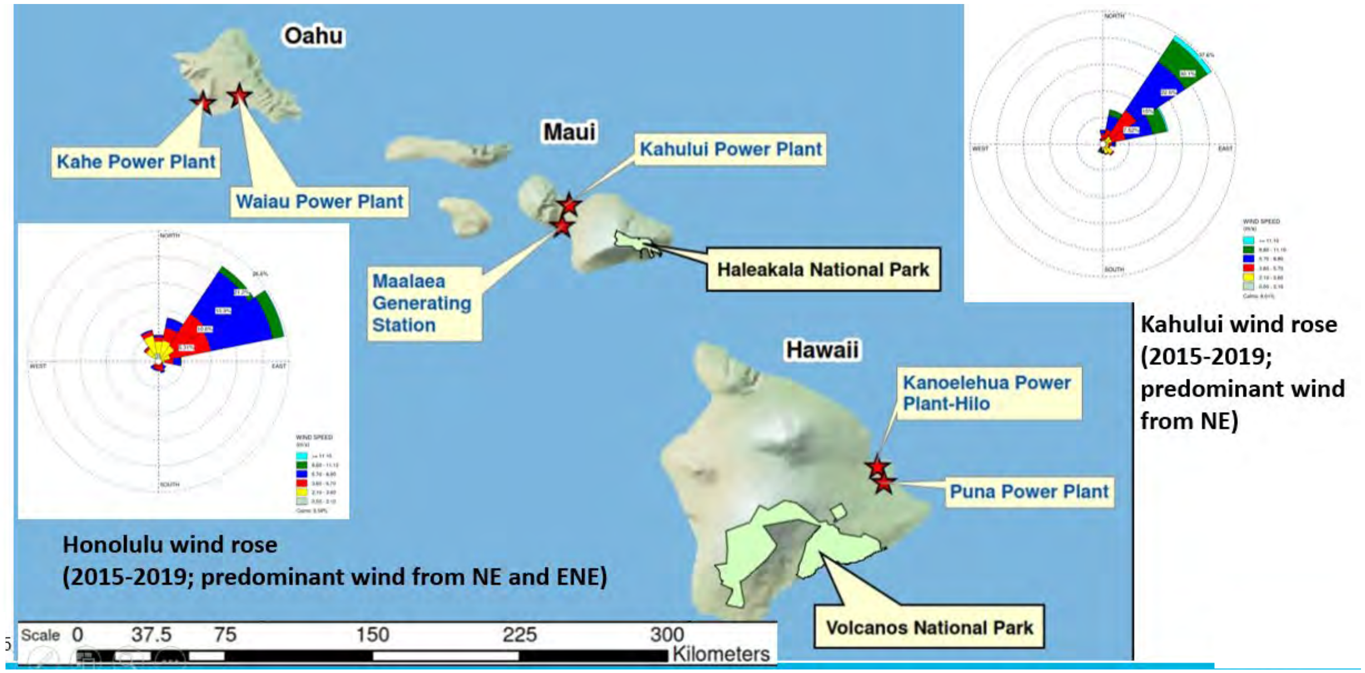
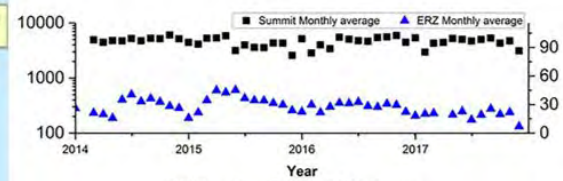


Figure B-11: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

2017 SO_2 Emissions (from NEI)

site name	TPY SO2
HELCO - Keahole Power Plant	81.94
HELCO - Waimea Power Plant	0.00
HELCO - Kanoelehua Power Plant/ HILL	2167.18
HELCO - Puna Power Plant	186.84

2014-2017 Volcano SO_2 Emissions average about 1.86 Million TPY



ERZ = Eastern Rift Zone

7. Conclusions

The state of Hawaiʻi is isolated from all other states and has very unique regional haze issues due, in part, to its tropical climate, the prevalent trade winds, very large natural emissions of haze precursors, and statewide commitment to renewable energy.

- Emission sources on Oʻahu and Maui are downwind of Hawaiʻi's Class 1 areas and do not contribute to haze issues, such that additional emission controls would not contribute to further reasonable progress at either of Hawaiʻi's Class 1 area National Parks. This is consistent with the EPA's First Decadal Review findings.

- Additionally, NOx emissions do not significantly contribute to haze in Hawaiʻi due the nitrate chemistry and Hawaiʻi's warm climate, and additional NOx controls would likewise not contribute to further reasonable progress. Therefore, NOx should not be regulated as a contributing precursor to haze in Hawaiʻi; especially from Oʻahu and Maui sources that are downwind of the parks. If they are reviewed as precursors, consideration should be given to their insignificant contribution when evaluating possible controls.

- Direct PM emissions constitute a very small portion of the haze associated with the worst 20% haze days in the Hawaiʻi Class 1 areas. Furthermore, significant portions of the observed haze in the categories of elemental carbon, soil, and coarse mass are due to volcanic emissions. Therefore, further PM controls on power plant sources would not have a significant benefit for visibility at these Class 1 areas.

- For the above reasons, the only pollutant that should be considered for possible haze controls in the state of Hawaiʻi is SO_2 which is consistent with the findings of the First Decadal Review. Furthermore, the only Hawaiian Electric sources to be considered for a four factor analysis for SO_2 should be those that are predominantly upwind of a Class I area which include only the Puna and Kanoelehua-Hill Generating Stations on Hawaiʻi Island.

- Hawaiʻi's Class I area haze impacts are principally due to natural sources. Volcanic emissions of precursor SO_2 during the 2014-2017 period of analysis were three orders of magnitude greater than the anthropogenic emissions on Hawaiʻi Island. Since these natural emissions are the principal cause of haze at the two Class 1 areas in the state and are difficult to distinguish from the relatively small amount of anthropogenically-caused haze, photochemical grid modeling is not practical or even needed. The definition of "impaired days" for Hawaiʻi Volcanoes National Park as referenced in some of the figures in this report is uncertain due to the overwhelming influence of natural emissions of SO_2.

- For Haleakalā National Park, with the lack of upwind anthropogenic sources, it could be reasonably concluded that natural conditions are already attained, and no further Reasonable Progress modeling (or controls) is needed. For Hawaiʻi Volcanoes National Park, the only United

States anthropogenic potential sources are those upwind of the park on Hawai'i Island; all other sources in the state are not contributing to haze at the Class 1 areas.

- Implementation of Hawai'i's RPS (discussed in detail in Appendix C) will provide a dramatic reduction of virtually all power plant haze-causing emissions in the state of Hawai'i well before the year 2064. This Hawai'i state law established enforceable requirements that a certain percentage of electricity must be generated from renewable energy sources by the end of identified benchmark years leading to 100percent renewable energy by 2045. The interim targets are 30 percent by 2020, 40 percent by 2030, and 70 percent by 2040 which provide an RPS "glide path" for EGUs that mirrors the RHR visibility improvement glide path for the next few decades. No separate new regional haze measures for EGUs are needed to assure reasonable progress for this decadal period.

Plans for renewable energy sources, the likely reduction in utilization of fossil-fueled electric generation in this interim period, the unique climate and wind patterns, and the difficulty of addressing the high volcanic emissions should be considered in the current planning for the Second Decadal Review process for the state of Hawai'i.

Appendix C:
Hawai‘i’s Renewable Portfolio Standards (“RPS”) Contribution to Regional Haze Progress

AECOM Project Number: 60626547

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March 30, 020

Hawaiʻi's Renewable Portfolio Standards ("RPS") Contribution to Regional Haze Progress

1. Executive Summary

Hawaiʻi's ongoing conversion of fossil-fueled electric generation to renewable energy sources as mandated by the Hawaiʻi Revised Statute ("HRS") §269-92 Renewable Portfolio Standards ("RPS") is significantly decreasing emissions from Hawaiʻi's electric generating stations. Past actual and expected future decreases in usage of fossil-fueled electric generating units ("EGUs") are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the Regional Haze Rule ("RHR"). Emissions from the majority of Hawaiʻi's electric generating plants are not a significant contributor to haze at Class I areas (for reasons explained in Appendix B). Further, their very low impact is being mitigated under the RPS state law. This rate of progress from the RPS law can be relied upon for further emissions reductions from EGUs in the coming years and thus separate further requirements for EGU controls under the RHR are not needed at this time. The following sections of this appendix provide a background on the RPS requirements and progress to date, and high confidence of continued progress consistent with the goals of the RHR.

2. Renewable Portfolio Standards

In 2002 the Hawaiʻi RPS legislation set voluntary goals for converting the islands' electrical generation from fossil fuels to renewable energy. In 2005, the RPS was set into law as binding requirements for Hawaiʻi electric utility companies. The law requires that electric utilities in Hawaiʻi achieve 100% of their electric generation from renewable energy sources by 2045 and meet a series of interim limits for the percentages of their electricity sales that must be provided by renewables (e.g., 30% renewable by 2020, and 40% by 2030, etc.). Renewable energy sources such as solar, hydro and wind energy have no direct emissions. Others such as biomass combustion have significantly lower emissions (especially sulfur dioxide ("SO_2")) than fossil fuels. Consequently, the RPS law results in steady progress in emissions reductions from electric utilities creating, in effect, an "RPS glidepath" providing dramatic reduction of electric generating unit emissions by mid-century.

The RPS program, although not directly related to the Regional Haze Rule ,is providing emissions reductions and improvements to air quality consistent with the goals of the RHR.

Table C-1 shows the interim and final RPS for EGUs along with the Regional Haze adjusted glidepath emissions reductions goals[1].

[1] Regional Haze Adjusted Glidepath assumes consistent reductions in haze precursor emissions impacts from all U.S. anthropogenic sources from the baseline average of 2000-2004 to zero impacts in 2064, i.e. natural background.

Table C-1 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement
2010	10%	8%
2015	15%	17%
2020	30%	25%
2030	40%	42%
2040	70%	58%
2045	100%	67%
2065		100%

This table illustrates that the emissions reductions from EGUs under the RPS are similar to the visibility goals of the Regional Haze Program in the intermediate years and become much more stringent in later years. The RPS seeks to achieve 100% renewable electrical supply by 2045, which is twenty years earlier than the RHR target of 2065 to achieve natural background visibility in Class I areas.

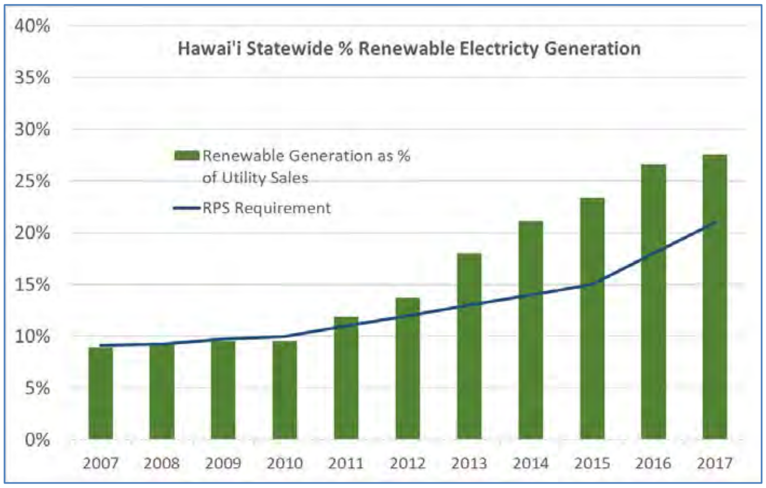
3. Historical RPS Achievement

Hawaiian Electric[2], and other electric utility providers in Hawaiʻi, have made excellent progress in developing and supporting renewable energy sources. Figure C-1 below shows the percentage of all electrical sales statewide provided by renewable sources since the RPS inception (green columns).[3] It also shows as a line illustrating the RPS interim standards (with proportional progress assumed between RPS milestone years). This figure illustrates that Hawaiʻi EGUs have made significant progress to date and have been ahead of the RPS interim targets.

Hawaiian Electric represents majority of Hawaiʻi's electric generation. Figure C-2 shows the renewable energy source percentages for this same period specifically for Hawaiian Electric. The data follows the same trend as the statewide figures and this figure also shows a breakdown of the type of renewable energy technology used.

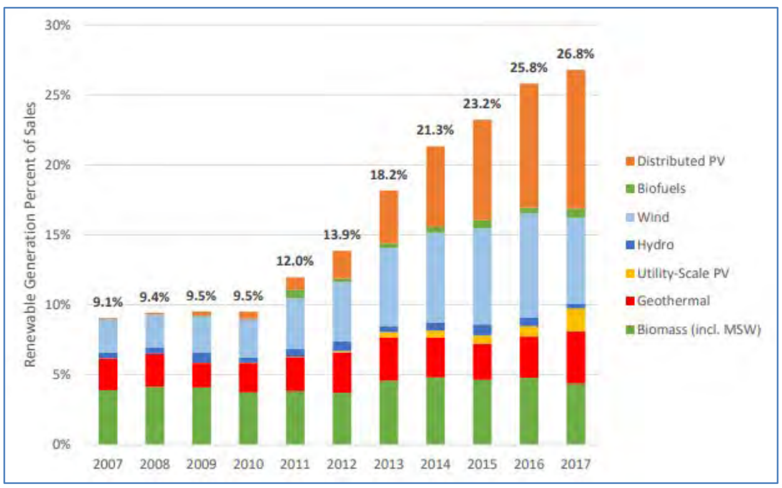
[2] "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawaiʻi Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawaiʻi Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.
[3] *Hawaiʻi Public Utility Commission* (PUC), *"Report to the 2019 Legislature on Hawaiʻi's Renewable Portfolio Standards", Dec. 2018* https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

Figure C-1 Statewide Renewable Portfolio Progress



Source: https://puc.Hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf

Figure C-2 Hawaiian Electric Companies RPS Achievement by Generation Technology[4]



[4] PUC Dec. 2018 Report, Figure 2, page 7.

4. Future RPS Achievability

To date, Hawai'i's electric utilities have generally met or exceeded the RPS requirements. Continued progress consistent with RPS is expected to continue. Projects and plans are already in place to continue this rapid RPS shift to renewable energy sources for the period of interest of the next decadal period of the RHR. In its December 2018 report to the state legislature, the Hawai'i Public Utility Commission ("PUC") indicated that *"future renewable projects under construction or planned for the HECO Companies and KIUC should ensure that the state remains on track for meeting the 2020 and 2030 RPS targets."*[5]

Figure C-3 below shows Hawaiian Electric's projection of percent renewables through 2030 presented in the December 2018 PUC report. This projected progress remains well ahead of the RPS requirements which also is ahead of the requirements of the Regional Haze glidepath goals.

Figure C-3 Hawaiian Electric Companies RPS Expectation by 2030 Technology[6]

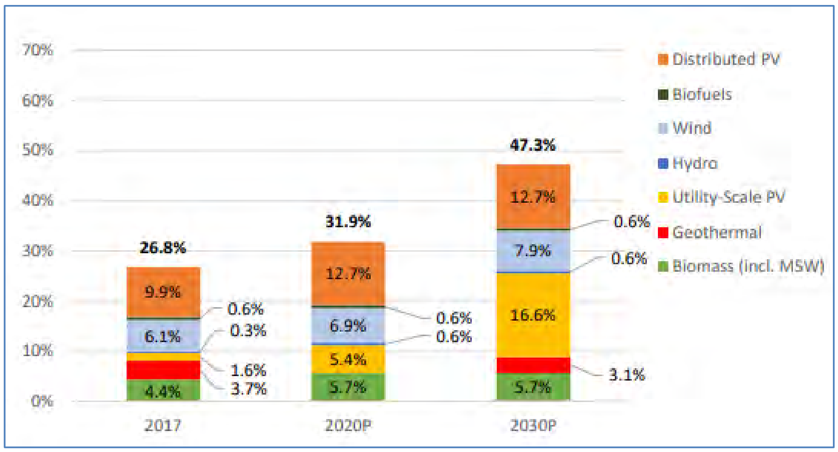


Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC's 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric's renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian Electric has an internal target to achieve 100% renewables by 2040, five years ahead of the RPS requirement and 25 years ahead of the RHR goals.

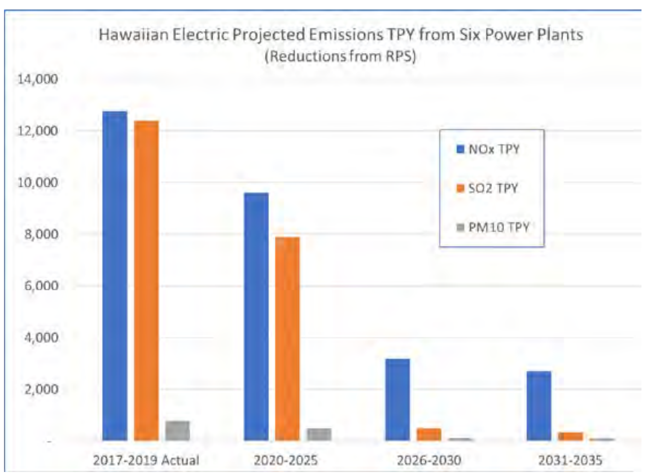
[5] PUC Dec. 2018 Report, page 2.
[6] PUC Dec. 2018 Report, Figure 2, page 16.

Table C-2 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement	Hawaiian Electric % Renewables
2010	10%	8%	9.5% (actual)
2015	15%	17%	23.2% (actual)
2020	30%	25%	31.9% (projection)
2030	40%	42%	47.3% (projection)
2040	70%	58%	100% (goal)
2045	100%	67%	100% (goal)

Hawaiian Electric's latest projections show an even more rapid shift to renewable energy sources than forecasted in 2018. This will continue to decrease Hawaiian Electric facility emissions. For example, Figure C-4 illustrates Hawaiian Electric's latest forecast emissions trends for total nitrogen oxides ("NOx"), sulfur dioxide ("SO_2") and Particulate Matter ("PM_{10}") emissions (in tons per year "TPY") from the six power plants (Waiau and Kahe Generating Stations on Oahu, Kahului and Maalaea on Maui, and Kanoelehua-Hill and Puna on Hawaiʻi) requested to conduct Four-Factor Analyses by the Hawaiʻi Department of Health ("DOH"). These dramatic emissions decreases illustrate the expected progress from RPS alone – without any additional RHR measures The forecast emissions shown in Figure C-4 was derived from recent fuel consumption projections based on the resource plans and planning assumptions submitted to the PUC as part of Hawaiian Electric's 2016 Power Supply Improvement Plan ("PSIP") which was accepted by the PUC and recent renewable project applications.

Figure C-4 Hawaiian Electric NOx Forecast Emissions



The emissions reduction is quite rapid and most of the projected reduction by Hawaiian Electric are expected to be in place prior to 2028, the next Regional Haze planning milestone.

Although this projection is based on reasonable assumptions, plans are subject to change as there is some uncertainty regarding future projections and forecast assumptions. For this reason and due to energy security issues, Hawaiian Electric cannot commit to specific dates for particular emissions reductions or final retirements of any specific generating station. Nevertheless, Hawaiian Electric is on an aggressive path to end fossil-fueled generation and replace it with renewable energy sources – especially during this next decadal period. This progress should be sufficient for Hawaiian Electric's contribution to the state's efforts regarding reasonable progress of the RHR for the current Regional Haze decadal review.

5. Reliance on RPS for this Regional Haze Decadal Review

The RPS requirements are part of Hawaiʻi state law. An electric utility failing to meet the RPS requirements is subject to enforcement action and penalties by the PUC unless the PUC determines the electric utility is unable to meet the RPS due to factors beyond its reasonable control. However, given the progress to date of the Hawaiʻi electric utilities acquiring renewable generation and expectations for planned renewable projects in the near future, it is reasonable to expect that RPS will result in continued steady progress, at least through 2030.

The DOH can rely on the RPS for regional haze progress without having to impose separate RHR requirements in facility permits. This is supported by EPA guidance which states that "Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and verifiable basis for quantifying any change in future emissions due to operational changes may be another."[7]

Even if progress were slower than currently expected, it would not prevent the RPS from being relied upon as the major EGU contribution to meeting Hawaiʻi's regional haze goals. The time perspective of the Regional Haze Program is long. Making wise decisions that help achieve the long-term goals is important. Hawaiʻi electric utilities are currently focusing resources on advancing renewable energy projects that will permanently displace fossil-fueled unit generation and fossil-fueled combustion emissions. These ongoing RPS efforts help achieve the long-term goals of the RHR and provide permanent emissions reductions and other societal benefits. In contrast, new investments in conventional emissions controls on aging fossil-fueled units provide only modest short-term benefits impose additional costs on rate payers and will have no lasting value when those units are deactivated or retired.

[7] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period – August 2019 at page 17. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Appendix Table D-1. Residual Low Sulfur Fuel Oil (LSFO) Cost

Date	Residual Low Sulfur Fuel Oil (LSFO) [A]	
	($/BBL)	($/gal)
Jan-18	$72.18	$1.72
Feb-18	$76.55	$1.82
Mar-18	$78.90	$1.88
Apr-18	$75.53	$1.80
May-18	$75.76	$1.80
Jun-18	$82.18	$1.96
Jul-18	$90.27	$2.15
Aug-18	$88.71	$2.11
Sep-18	$89.95	$2.14
Oct-18	$88.46	$2.11
Nov-18	$92.63	$2.21
Dec-18	$101.89	$2.43
Jan-19	$83.76	$1.99
Feb-19	$62.69	$1.49
Mar-19	$76.63	$1.82
Apr -19 [B]	$1,888.78	$44.97
May-19	$85.95	$2.05
Jun-19	$83.60	$1.99
Jul-19	$79.61	$1.90
Aug-19	$77.66	$1.85
Sep-19	$77.29	$1.84
Oct-19	$73.85	$1.76
Nov-19	$74.39	$1.77
Dec-19	$72.52	$1.73
2018-19 Annual Average	**$80.75**	**$1.93**

[A] Fuel cost from the 2019 and 2018 Energy Cost Recovery Filings submitted to the Hawai'i Public Utilities Commission. (https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/energy-cost-filings/oahu-energy-cost-filings)

[B] April 2019 was not included in the average due to an unusually high $/bbl.

Appendix Table D-2. Ultra-Low Sulfur Diesel (ULSD) Import Cost

Description	Value	Units
Platts 2018 Price [A]	86.75	$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	88.05	$/BBL
Freight [B]	5.51	$/BBL
Terminalling Fee [B]	2.00	$/BBL
Total ULSD Import Cost [C]	**95.56**	**$/BBL**
	2.28	**$/Gal**

[A] S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 10 ppm which is comparable to ULSD. (https://www.spglobal.com/platts/plattscontent/_assets/_files/en/productsservices/market-reports/oilgram-proce-report-060818.pdf)

[B] Hawaiian Electric Fuels Division Estimate.

[C] Platts 2019 spot price plus freight and terminalling fees.

Control Cost Worksheets and DOH-CAB Revisions

Changes Summarized

3.25 % interest rate for controls

30 year equipment life for SCR

20 year equipment life for all other controls*

SNCR retrofit factor of 1

* **Equipment life of CDS were reassess at 30 years based on upcoming revision to the cost control manual.**

Table 3-2. SO_2 Cost Effectiveness of CDS

Unit	Control Option	2017 SO_2 Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	CDS	841.8	0.045	3,778,041	84.2	757.6	$10,608,072	$14,002
K2	CDS	659.5	0.045	2,959,869	66.0	593.6	$10,800,319	$18,196
K3	CDS	836.3	0.045	3,753,356	83.6	752.7	$11,589,051	$15,397
K4	CDS	859.8	0.045	3,858,826	86.0	773.8	$11,023,741	$14,246
K5	CDS	1,136.2	0.045	5,099,323	113.6	1,022.6	$18,694,104	$18,281
K6	CDS	1,431.5	0.045	6,424,644	143.2	1,288.4	$17,000,254	$13,195

Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Controlled emission levels based on 90% control.

See Appendix A for total annual cost calculations.

Original Submitted Spreadsheet

Table 3-2. SO_2 Cost Effectiveness of CDS (20 Yrs Life)

Unit	Control Option	2017 SO_2 Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	CDS	841.8	0.045	3,778,041	84.2	757.6	$9,709,255	$12,815
K2	CDS	659.5	0.045	2,959,869	66.0	593.6	$9,901,501	$16,682
K3	CDS	836.3	0.045	3,753,356	83.6	752.7	$10,690,233	$14,203
K4	CDS	859.8	0.045	3,858,826	86.0	773.8	$10,124,923	$13,084
K5	CDS	1,136.2	0.045	5,099,323	113.6	1,022.6	$17,306,804	$16,925
K6	CDS	1,431.5	0.045	6,424,644	143.2	1,288.4	$15,612,953	$12,119

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] Controlled emission levels based on 90% control.

[C] See Appendix A for total annual cost calculations.

DOH-CAB Changed Spreadsheet (20 Yrs Life)

Table 3-2. SO_2 Cost Effectiveness of CDS (30 Yrs Life)

Unit	Control Option	2017 SO_2 Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled SO_2 Emissions (tpy)	SO_2 Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	CDS	841.8	0.045	3,778,041	84.2	757.6	$8,483,898	$11,198
K2	CDS	659.5	0.045	2,959,869	66.0	593.6	$8,676,145	$14,617
K3	CDS	836.3	0.045	3,753,356	83.6	752.7	$9,464,877	$12,575
K4	CDS	859.8	0.045	3,858,826	86.0	773.8	$8,899,567	$11,501
K5	CDS	1,136.2	0.045	5,099,323	113.6	1,022.6	$15,415,500	$15,075
K6	CDS	1,431.5	0.045	6,424,644	143.2	1,288.4	$13,721,650	$10,651

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] Controlled emission levels based on 90% control.

[C] See Appendix A for total annual cost calculations.

DOH-CAB Changed Spreadsheet (30 Yrs Life)

Table 3-3. SO_2 Cost Effectiveness of Fuel Switching to a Residual Oil/ULSD Blend

Unit	Current Residual Oil (0.50% maximum Sulfur) [A]					Residual Oil/ULSD Blend (0.25% maximum Sulfur) [B]						
	2017 Average Sulfur Content	Fuel Heating Value (HHV)	Annual Fuel Usage	2017 Annual Heat Input	2017 SO_2 Emissions [D]	Fuel Heating Value (HHV)	Annual Fuel Usage	Controlled SO_2 Emissions	SO_2 Reduced	Fuel Cost Differential [C]		SO_2 Cost Effectiveness
	(%)	(Btu/gal)	(gal/yr)	(MMBtu/yr)	(tpy)	(Btu/gal)	(gal/yr)	(tpy)	(tpy)	($/Gal)	($/yr)	($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	143,071	26,406,754	493.0	348.8	0.18	$4,621,182	13,250
K2	0.42%	149,479	19,801,237	2,959,869	659.5	143,071	20,688,114	386.3	273.2	0.18	$3,620,420	13,250
K3	0.42%	149,479	25,109,590	3,753,356	836.3	143,071	26,234,222	489.8	346.5	0.18	$4,590,989	13,250
K4	0.42%	149,479	25,815,168	3,858,826	859.8	143,071	26,971,403	503.6	356.2	0.18	$4,719,995	13,250
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	143,071	35,641,903	665.5	470.7	0.18	$6,237,333	13,250
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	143,071	44,905,284	838.4	593.1	0.18	$7,858,425	13,250

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on a blend of 50.0% residual oil and 50.0% ULSD and the weighted averge of the 2017 fuel HHV and density for residual oil and ULSD, and contract fuel sulur limits.

[C] See Appendix D for fuel cost.

[D] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-4. SO_2 Cost Effectiveness of Fuel Switching to ULSD

Unit	Current Residual Oil (0.50% maximum Sulfur) [A]					ULSD (0.0015% maximum Sulfur) [B]						
	2017 Average Sulfur Content	Fuel Heating Value (HHV)	Annual Fuel Usage	2017 Annual Heat Input	2017 SO_2 Emissions [D]	Fuel Heating Value (HHV)	Annual Fuel Usage	Controlled SO_2 Emissions	SO_2 Reduced	Fuel Cost Differential [C]		SO_2 Cost Effectiveness
	(%)	(Btu/gal)	(gal/yr)	(MMBtu/yr)	(tpy)	(Btu/gal)	(gal/yr)	(tpy)	(tpy)	($/Gal)	($/yr)	($/ton)
K1	0.42%	149,479	25,274,725	3,778,041	841.8	136,662	27,645,144	3.8	838.0	0.36	$9,814,026	11,711
K2	0.42%	149,479	19,801,237	2,959,869	659.5	136,662	21,658,318	3.0	656.5	0.36	$7,688,703	11,711
K3	0.42%	149,479	25,109,590	3,753,356	836.3	136,662	27,464,521	3.8	832.5	0.36	$9,749,905	11,711
K4	0.42%	149,479	25,815,168	3,858,826	859.8	136,662	28,236,273	3.9	855.9	0.36	$10,023,877	11,711
K5	0.42%	149,479	34,113,973	5,099,323	1,136.2	136,662	37,313,391	5.1	1,131.1	0.36	$13,246,254	11,711
K6	0.42%	149,479	42,980,244	6,424,644	1,431.5	136,662	47,011,195	6.4	1,425.1	0.36	$16,688,974	11,711

[A] Based on 2017 average fuel properties and fuel usage.

[B] Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

[C] See Appendix D for fuel cost.

[D] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Original Submitted Spreadsheet

Table 4-4. NO_X Cost Effectiveness of Controls Summary

Unit	Control Option	2017 NO_X Emissions [A] (tpy)	Controlled Emission Level [B,C] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_X Emissions (tpy)	NO_X Reduced (ton/yr)	Total Annual Cost [D,E] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	932.7	0.38	3,778,041	718.2	214.5	$4,621,182	$21,542
	ULSD	932.7	0.27	3,778,041	513.0	419.7	$9,814,026	$23,383
	Combustion Controls	932.7	0.30	3,778,041	566.7	366.0	$482,550	$1,318
	SNCR	932.7	0.40	3,778,041	755.6	177.1	$854,332	$4,824
	SNCR+Combustion Controls	932.7	0.20	3,778,041	377.8	554.9	$1,336,882	$2,409
	SCR	932.7	0.10	3,778,041	188.9	743.8	$2,210,698	$2,972
	SCR+Combustion Controls	932.7	0.05	3,778,041	94.5	838.2	$2,693,248	$3,213
K2	Residual Oil/ULSD Blend	963.0	0.50	2,959,869	741.5	221.5	$3,620,420	$16,346
	ULSD	963.0	0.36	2,959,869	529.7	433.4	$7,688,703	$17,742
	Combustion Controls	963.0	0.30	2,959,869	444.0	519.0	$467,426	$901
	SNCR [F]	963.0	0.40	2,959,869	592.0	371.0	$854,332	$2,303
	SNCR+Combustion Controls	963.0	0.20	2,959,869	296.0	667.0	$1,321,758	$1,982
	SCR	963.0	0.10	2,959,869	148.0	815.0	$2,083,950	$2,557
	SCR+Combustion Controls	963.0	0.05	2,959,869	74.0	889.0	$2,551,376	$2,870
K3	Residual Oil/ULSD Blend	661.7	0.32	3,753,356	595.5	66.2	$4,590,989	$69,382
	ULSD	661.7	0.28	3,753,356	529.4	132.3	$9,749,905	$73,673
	Combustion Controls	661.7	0.20	3,753,356	375.3	286.4	$346,310	$1,209
	SNCR	661.7	0.25	3,753,356	469.2	192.5	$789,403	$4,100
	SNCR+Combustion Controls	661.7	0.15	3,753,356	281.5	380.2	$1,135,713	$2,987
	SCR	661.7	0.10	3,753,356	187.7	474.0	$2,171,338	$4,581
	SCR+Combustion Controls	661.7	0.05	3,753,356	93.8	567.9	$2,517,649	$4,434
K4	Residual Oil/ULSD Blend	732.2	0.34	3,858,826	659.0	73.2	$4,719,995	$64,463
	ULSD	732.2	0.30	3,858,826	585.8	146.4	$10,023,877	$68,450
	Combustion Controls	732.2	0.20	3,858,826	385.9	346.3	$349,044	$1,008
	SNCR [F]	732.2	0.25	3,858,826	482.4	249.8	$789,403	$3,160
	SNCR+Combustion Controls	732.2	0.15	3,858,826	289.4	442.8	$1,138,447	$2,571
	SCR	732.2	0.10	3,858,826	192.9	539.3	$2,202,873	$4,085
	SCR+Combustion Controls	732.2	0.05	3,858,826	96.5	635.7	$2,551,917	$4,014
K5	Residual Oil/ULSD Blend	2,044.2	0.62	5,099,323	1,574.0	470.2	$6,237,333	$13,266
	ULSD	2,044.2	0.44	5,099,323	1,124.3	919.9	$13,246,254	$14,400
	Combustion Controls	2,044.2	0.30	5,099,323	764.9	1,279.3	$638,537	$499
	SNCR	2,044.2	0.40	5,099,323	1019.9	1024.3	$1,358,582	$1,326
	SNCR+Combustion Controls	2,044.2	0.20	5,099,323	509.9	1534.3	$1,997,119	$1,302
	SCR	2,044.2	0.10	5,099,323	255.0	1,789.2	$3,058,173	$1,709
	SCR+Combustion Controls	2,044.2	0.05	5,099,323	127.5	1,916.7	$3,696,710	$1,929
K6	Residual Oil/ULSD Blend	630.1	0.16	6,424,644	516.7	113.4	$7,858,425	$69,287
	ULSD	630.1	0.13	6,424,644	403.3	226.8	$16,688,974	$73,573
	SNCR [G]	630.1	0.15	6,424,644	481.8	148.3	$883,819	$5,962
	SCR [G]	630.1	0.05	6,424,644	160.6	469.5	$3,045,798	$6,488

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010. The controlled emission level for the 50/50 residual oil/ULSD blend is based on the average of the AP-42 emission factor for No. 2 fuel oil and the 2017 emission factor.

[C] Controlled emission levels based on "Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler" EPA, 1994.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019 dollars.

[E] See Appendix A for the total annual cost calculations for combustion controls, SNCR and SCR.

[F] The annual cost for K2 is based on K1 which has a similar design and rating and the annual cost for K4 is based on K3 which has a similar design and rating.

[G] K6 is equipped with combustion controls, the level of SCR control was reduced to 0.05 lb/MMBtu to account for the combined level of control.

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Table 4-4. NO_X Cost Effectiveness of Controls Summary

Unit	Control Option	2017 NO_X Emissions [A] (tpy)	Controlled Emission Level [B,C] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_X Emissions (tpy)	NO_X Reduced (ton/yr)	Total Annual Cost [D,E] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	932.7	0.38	3,778,041	718.2	214.5	$4,621,182	$21,542
	ULSD	932.7	0.27	3,778,041	513.0	419.7	$9,814,026	$23,383
	Combustion Controls	932.7	0.30	3,778,041	566.7	366.0	$428,048	$1,170
	SNCR	932.7	0.40	3,778,041	755.6	177.1	$550,535	$3,109
	SNCR+Combustion Controls	932.7	0.20	3,778,041	377.8	554.9	$978,583	$1,764
	SCR	932.7	0.10	3,778,041	188.9	743.8	$1,386,756	$1,864
	SCR+Combustion Controls	932.7	0.05	3,778,041	94.5	838.2	$1,814,804	$2,165
K2	Residual Oil/ULSD Blend	963.0	0.50	2,959,869	741.5	221.5	$3,620,420	$16,346
	ULSD	963.0	0.36	2,959,869	529.7	433.4	$7,688,703	$17,742
	Combustion Controls	963.0	0.30	2,959,869	444.0	519.0	$413,686	$797
	SNCR [F]	963.0	0.40	2,959,869	592.0	371.0	$550,535	$1,484
	SNCR+Combustion Controls	963.0	0.20	2,959,869	296.0	667.0	$964,221	$1,446
	SCR	963.0	0.10	2,959,869	148.0	815.0	$1,272,051	$1,561
	SCR+Combustion Controls	963.0	0.05	2,959,869	74.0	889.0	$1,685,738	$1,896
K3	Residual Oil/ULSD Blend	661.7	0.32	3,753,356	595.5	66.2	$4,590,989	$69,382
	ULSD	661.7	0.28	3,753,356	529.4	132.3	$9,749,905	$73,673
	Combustion Controls	661.7	0.20	3,753,356	375.3	286.4	$305,434	$1,067
	SNCR	661.7	0.25	3,753,356	469.2	192.5	$484,414	$2,516
	SNCR+Combustion Controls	661.7	0.15	3,753,356	281.5	380.2	$789,848	$2,077
	SCR	661.7	0.10	3,753,356	187.7	474.0	$1,346,975	$2,842
	SCR+Combustion Controls	661.7	0.05	3,753,356	93.8	567.9	$1,652,409	$2,910
K4	Residual Oil/ULSD Blend	732.2	0.34	3,858,826	659.0	73.2	$4,719,995	$64,463
	ULSD	732.2	0.30	3,858,826	585.8	146.4	$10,023,877	$68,450
	Combustion Controls	732.2	0.20	3,858,826	385.9	346.3	$307,883	$889
	SNCR [F]	732.2	0.25	3,858,826	482.4	249.8	$484,414	$1,939
	SNCR+Combustion Controls	732.2	0.15	3,858,826	289.4	442.8	$792,297	$1,789
	SCR	732.2	0.10	3,858,826	192.9	539.3	$1,372,847	$2,546
	SCR+Combustion Controls	732.2	0.05	3,858,826	96.5	635.7	$1,680,730	$2,644
K5	Residual Oil/ULSD Blend	2,044.2	0.62	5,099,323	1,574.0	470.2	$6,237,333	$13,266
	ULSD	2,044.2	0.44	5,099,323	1,124.3	919.9	$13,246,254	$14,400
	Combustion Controls	2,044.2	0.30	5,099,323	764.9	1,279.3	$566,552	$443
	SNCR	2,044.2	0.40	5,099,323	1019.9	1024.3	$942,382	$920
	SNCR+Combustion Controls	2,044.2	0.20	5,099,323	509.9	1534.3	$1,508,934	$983
	SCR	2,044.2	0.10	5,099,323	255.0	1,789.2	$1,967,607	$1,100
	SCR+Combustion Controls	2,044.2	0.05	5,099,323	127.5	1,916.7	$2,534,159	$1,322
K6	Residual Oil/ULSD Blend	630.1	0.16	6,424,644	516.7	113.4	$7,858,425	$69,287
	ULSD	630.1	0.13	6,424,644	403.3	226.8	$16,688,974	$73,573
	SNCR [G]	630.1	0.15	6,424,644	481.8	148.3	$527,988	$3,561
	SCR [G]	630.1	0.05	6,424,644	160.6	469.5	$1,953,690	$4,161

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

[B] The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010. The controlled emission level for the 50/50 residual oil/ULSD blend is based on the average of the AP-42 emission factor for No. 2 fuel oil and the 2017 emission factor.

[C] Controlled emission levels based on "Alternative Control Techniques (ACT) Document – NO_X Emissions from Utility Boiler" EPA, 1994.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019 dollars.

[E] See Appendix A for the total annual cost calculations for combustion controls, SNCR and SCR.

[F] The annual cost for K2 is based on K1 which has a similar design and rating and the annual cost for K4 is based on K3 which has a similar design and rating.

[G] K6 is equipped with combustion controls, the level of SCR control was reduced to 0.05 lb/MMBtu to account for the combined level of control.

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Table 5-3. PM_{10} Cost Effectiveness Summary

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Controlled Emission Level [B] (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	55.7	0.0203	3,778,041	38.4	17.3	$4,621,182	$267,631
	ULSD	55.7	0.0112	3,778,041	21.2	34.5	$9,814,026	$284,184
K2	Residual Oil/ULSD Blend	39.3	0.0183	2,959,869	27.1	12.2	$3,620,420	$297,170
	ULSD	39.3	0.0101	2,959,869	14.9	24.4	$7,688,703	$315,550
K3	Residual Oil/ULSD Blend	51.7	0.0190	3,753,356	35.7	16.0	$4,590,989	$286,453
	ULSD	51.7	0.0105	3,753,356	19.6	32.1	$9,749,905	$304,171
K4	Residual Oil/ULSD Blend	50.5	0.0181	3,858,826	34.8	15.7	$4,719,995	$301,501
	ULSD	50.5	0.0099	3,858,826	19.2	31.3	$10,023,877	$320,149
K5	Residual Oil/ULSD Blend	78.7	0.0213	5,099,323	54.3	24.4	$6,237,333	$255,660
	ULSD	78.7	0.0117	5,099,323	29.9	48.8	$13,246,254	$271,473
K6	Residual Oil/ULSD Blend	108.6	0.0233	6,424,644	74.9	33.7	$7,858,425	$233,423
	ULSD	108.6	0.0128	6,424,644	41.3	67.3	$16,688,974	$247,861

[A] Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).
[B] The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010. The controlled emission level for the 50/50 residual oil/ULSD blend is based on the average of the AP-42 emission factor for No. 2 fuel oil and the 2017 emission factor.
[C] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019 dollars.

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Table 6-1 Total Cost Effectiveness of Fuel Switching

Unit	Control Option	SO_2 Reduced [A] (ton/yr)	NO_X Reduced [A] (ton/yr)	PM_{10} Reduced [A] (ton/yr)	Total SO_2, NO_X, and PM_{10} Reduced (ton/yr)	Total Annual Cost [B] ($/yr)	Cost Effectiveness ($/ton)
K1	Residual Oil/ULSD Blend	348.8	214.5	17.3	580.6	$4,621,182	$7,960
	ULSD	838.0	419.7	34.5	1,292.3	$9,814,026	$7,594
K2	Residual Oil/ULSD Blend	273.2	221.5	12.2	506.9	$3,620,420	$7,142
	ULSD	656.5	433.4	24.4	1,114.3	$7,688,703	$6,900
K3	Residual Oil/ULSD Blend	346.5	66.2	16.0	428.7	$4,590,989	$10,709
	ULSD	832.5	132.3	32.1	996.9	$9,749,905	$9,780
K4	Residual Oil/ULSD Blend	356.2	73.2	15.7	445.1	$4,719,995	$10,604
	ULSD	855.9	146.4	31.3	1,033.7	$10,023,877	$9,697
K5	Residual Oil/ULSD Blend	470.7	470.2	24.4	965.3	$6,237,333	$6,462
	ULSD	1,131.1	919.9	48.8	2,099.8	$13,246,254	$6,308
K6	Residual Oil/ULSD Blend	593.1	113.4	33.7	740.2	$7,858,425	$10,617
	ULSD	1,425.1	226.8	67.3	1,719.2	$16,688,974	$9,707

[A] The SO_2, NO_X, and PM_{10} reduced are from Tables 3-3 and 3-4, Table 4-4, and Table 5-3, respectively.

[B] Annual costs for switching to a residual oil/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on 2019

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Appendix Table A-3a. Kahe K1 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	384,917	MWhs
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Plant Elevation: 10 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3a. Kahe K1 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.494	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.00	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3a. Kahe K1 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3a. Kahe K1 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	384,917	MWhs
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3a. Kahe K1 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.494	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3a. Kahe K1 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	3.25	Current prime inerest rate	

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Appendix Table A-3a. Kahe K1 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		384,917	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.478	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	355.55	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	743.80	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	418,214	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	111.61	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,746.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	436	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3a. Kahe K1 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	501	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.4	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	138	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	476	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	64	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	45,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	511.08	kW

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Appendix Table A-3a. Kahe K1 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		384,917	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	0.98	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.478	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4184	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.7	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	355.55	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	743.80	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	418,214	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	111.61	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,746.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	436	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3a. Kahe K1 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	501	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.4	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	138	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	476	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	64	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	45,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	511.08	kW

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Appendix Table A-3a. Kahe K1 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,543,429	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$793,017	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,417,681	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,210,698	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,717	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$78,028	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$539,069	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$88,203	in 2019 dollars
Direct Annual Cost =		$793,017	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,681	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,414,000	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,417,681	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,210,698	per year in 2019 dollars
NOx Removed =	744	tons/year
Cost Effectiveness =	$2,972	per ton of NOx removed in 2019 dollars

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Appendix Table A-3a. Kahe K1 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,695,620	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$767,067	in 2019 dollars
Indirect Annual Costs (IDAC) =	$619,689	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,386,756	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$58,478	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$78,028	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$539,069	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$91,492	in 2019 dollars
Direct Annual Cost =		$767,067	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,330	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$616,359	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$619,689	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,386,756	per year in 2019 dollars
NOx Removed =	744	tons/year
Cost Effectiveness =	$1,864	per ton of NOx removed in 2019 dollars

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Appendix Table A-3b. Kahe K2 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Utility	**What type of fuel does the unit burn?**	Fuel Oil
Is the SCR for a new boiler or retrofit of an existing boiler?	Retrofit		
Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.5	* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.	

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	90	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	295,987	MWhs
Enter the net plant heat input rate (NPHR)	10.0000	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3b. Kahe K2 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.651	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3b. Kahe K2 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3b. Kahe K2 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Utility	**What type of fuel does the unit burn?**	Fuel Oil
Is the SCR for a new boiler or retrofit of an existing boiler?	Retrofit		
Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1		

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	90	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	295,987	MWhs
Enter the net plant heat input rate (NPHR)	10.0000	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3b. Kahe K2 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.651	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3b. Kahe K2 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	3.25	Current prime interest rate	

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Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	900	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	788,400	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		295,987	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.375	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3289	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	84.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	495.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	815.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	416,824	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	101.67	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,099.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	434	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	499	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.3	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	193	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	664	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	89	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	63,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \text{ x } HRF)^{0.43}$ = where A = Bmw for utility boilers	504.00	kW

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Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	900	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	788,400	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		295,987	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.375	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3289	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	84.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	495.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	815.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.06		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	416,824	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	101.67	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,099.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	434	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3b. Kahe K2 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	499	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.3	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	193	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	664	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	89	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	63,900	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	504.00	kW

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Appendix Table A-3b. Kahe K2 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,294,581	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$686,341	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,397,609	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,083,950	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$86,473	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$85,498	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$417,862	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$96,508	in 2019 dollars
Direct Annual Cost =		$686,341	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,666	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,393,943	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,397,609	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,083,950	per year in 2019 dollars
NOx Removed =	815	tons/year
Cost Effectiveness =	$2,557	per ton of NOx removed in 2019 dollars

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Appendix Table A-3b. Kahe K2 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,529,720	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$661,115	in 2019 dollars
Indirect Annual Costs (IDAC) =	$610,936	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,272,051	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$57,649	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$85,498	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$417,862	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$100,106	in 2019 dollars
Direct Annual Cost =		$661,115	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,320	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$607,616	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$610,936	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,272,051	per year in 2019 dollars
NOx Removed =	815	tons/year
Cost Effectiveness =	$1,561	per ton of NOx removed in 2019 dollars

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Appendix Table A-3c. Kahe K3 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	387,117	MWhs
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3c. Kahe K3 - SCR Costing

Enter the following design parameters for the proposed SCR:

Parameter	Value	Unit
Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.353	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Parameter	Value	Unit
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Parameter	Value	Unit
Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Unit	Notes
Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3c. Kahe K3 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3c. Kahe K3 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	387,117	MWhs
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3c. Kahe K3 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.353	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3c. Kahe K3 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	3.25	Current prime interest rate	

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Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		387,117	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	71.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	225.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	474.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.90		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	413,119	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	126.44	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,267.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	430	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	495	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	302	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	508.40	kW

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Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	805,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		387,117	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	71.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	225.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	474.03	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.90		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	413,119	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	126.44	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,267.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	430	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3c. Kahe K3 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	495	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	302	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	508.40	kW

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Appendix Table A-3c. Kahe K3 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,543,429	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$753,657	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,417,681	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,171,338	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$87,717	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$49,728	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,302	in 2019 dollars
Annual Catalyst Replacement Cost =		$76,910	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$753,657	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,681	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,414,000	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,417,681	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,171,338	per year in 2019 dollars
NOx Removed =	474	tons/year
Cost Effectiveness =	$4,581	per ton of NOx removed in 2019 dollars

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Appendix Table A-3c. Kahe K3 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,695,620	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$727,286	in 2019 dollars
Indirect Annual Costs (IDAC) =	$619,689	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,346,975	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$58,478	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$49,728	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$539,302	in 2019 dollars
Annual Catalyst Replacement Cost =		$79,778	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$727,286	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,330	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$616,359	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$619,689	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,346,975	per year in 2019 dollars
NOx Removed =	474	tons/year
Cost Effectiveness =	$2,842	per ton of NOx removed in 2019 dollars

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Appendix Table A-3d. Kahe K4 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	93	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	390,927	MWhs
Enter the net plant heat input rate (NPHR)	9.8710	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3d. Kahe K4 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.379	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3d. Kahe K4 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3d. Kahe K4 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Fuel Oil

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	93	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	390,927	MWhs
Enter the net plant heat input rate (NPHR)	9.8710	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3d. Kahe K4 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.379	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	0.293	\$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	\$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3d. Kahe K4 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	3.25	Current primte interest rate	

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Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	918	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	814,680	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		390,927	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.99		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4204	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	73.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	256.58	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	539.26	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.92		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	425,161	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	122.82	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,461.60	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	443	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	509	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	100	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	344	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	46	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	33,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	517.90	kW

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Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	918	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	814,680	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		390,927	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.99		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.480	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4204	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	73.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	256.58	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	539.26	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.92		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	425,161	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	122.82	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,461.60	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	443	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3d. Kahe K4 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	509	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	22.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	100	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	344	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	46	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	33,100	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	517.90	kW

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Appendix Table A-3d. Kahe K4 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$17,667,143	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$775,213	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,427,660	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,202,873	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$88,336	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$56,571	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$548,821	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$81,486	in 2019 dollars
Direct Annual Cost =		$775,213	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,688	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,423,972	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,427,660	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,202,873	per year in 2019 dollars
NOx Removed =	539	tons/year
Cost Effectiveness =	$4,085	per ton of NOx removed in 2019 dollars

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Appendix Table A-3d. Kahe K4 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,778,095	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$748,806	in 2019 dollars
Indirect Annual Costs (IDAC) =	$624,040	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,372,847	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$58,890	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$56,571	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$548,821	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$84,524	in 2019 dollars
Direct Annual Cost =		$748,806	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,335	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$620,706	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$624,040	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,372,847	per year in 2019 dollars
NOx Removed =	539	tons/year
Cost Effectiveness =	$2,546	per ton of NOx removed in 2019 dollars

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Appendix Table A-3e. Kahe K5 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Utility	**What type of fuel does the unit burn?**	Fuel Oil
Is the SCR for a new boiler or retrofit of an existing boiler?	Retrofit		
Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.5	* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.	

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	493,259	MWhs
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3e. Kahe K5 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.802	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3e. Kahe K5 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3e. Kahe K5 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	493,259	MWhs
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

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Appendix Table A-3e. Kahe K5 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.802	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.1	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

DOH-CAB Changed Spreadsheet

Appendix Table A-3e. Kahe K5 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	3.25	Current prime interest rate	

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Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		493,259	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.397	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	87.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1030.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,789.23	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.09		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	679,886	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	94.77	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,173.70	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	708	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	814	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	28.5	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	400	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,381	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	184	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	132,800	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	806.65	kW

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Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		493,259	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.397	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	87.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1030.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,789.23	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.09		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	679,886	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	94.77	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,173.70	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	708	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

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Appendix Table A-3e. Kahe K5 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	814	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	28.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	400	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,381	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	184	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	132,800	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	806.65	kW

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Appendix Table A-3e. Kahe K5 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$23,261,613	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,179,264	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,878,910	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,058,173	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$116,308	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$187,699	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$706,389	in 2019 dollars
Annual Catalyst Replacement Cost =		$168,868	in 2019 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		
Direct Annual Cost =		$1,179,264	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,024	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,874,886	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,878,910	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,058,173	per year in 2019 dollars
NOx Removed =	1,789	tons/year
Cost Effectiveness =	$1,709	per ton of NOx removed in 2019 dollars

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Appendix Table A-3e. Kahe K5 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$15,507,742	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,146,791	in 2019 dollars
Indirect Annual Costs (IDAC) =	$820,816	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,967,607	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$77,539	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$187,699	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$706,389	in 2019 dollars
Annual Catalyst Replacement Cost =		$175,165	in 2019 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		
Direct Annual Cost =		$1,146,791	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,558	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$817,258	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$820,816	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,967,607	per year in 2019 dollars
NOx Removed =	1,789	tons/year
Cost Effectiveness =	$1,100	per ton of NOx removed in 2019 dollars

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Appendix Table A-3f. Kahe K6 - SCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

* A retrofit factor of 1.5 is appropriate for the proposed project due to Hawaii's remote location and the existing site layout.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWhs output?	601,781	MWhs
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Plant Elevation	10	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

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Appendix Table A-3f. Kahe K6 - SCR Costing

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.196	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

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

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	30	days

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

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.0	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.2521	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

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Appendix Table A-3f. Kahe K6 - SCR Costing

Maintenance and Administrative Charges Cost Factors:

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

Data Sources Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.00	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		601,781	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.484	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	74.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	221.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	469.48	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.93		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	702,117	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	129.61	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,417.25	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	731	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

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Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	841	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	29.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	86	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	297	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	28,600	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0806

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	817.89	kW

Original Submitted Spreadsheet

Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,243,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		601,781	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.484	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	74.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	221.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	469.48	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.93		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	702,117	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	129.61	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3227	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,417.25	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	731	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

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Appendix Table A-3f. Kahe K6 - SCR Costing

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	841	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	29.0	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	86	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	297	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	28,600	gallons (storage needed to store a 30 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	817.89	kW

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Appendix Table A-3f. Kahe K6 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$23,261,613	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,166,888	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,878,910	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,045,798	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$116,308	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$49,251	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$873,807	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$127,521	in 2019 dollars
Direct Annual Cost =		$1,166,888	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,024	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,874,886	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,878,910	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,045,798	per year in 2019 dollars
NOx Removed =	469	tons/year
Cost Effectiveness =	$6,488	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

Appendix Table A-3f. Kahe K6 - SCR Costing

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$15,507,742	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,132,873	in 2019 dollars
Indirect Annual Costs (IDAC) =	$820,816	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,953,690	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$77,539	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$49,251	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$873,807	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$132,276	in 2019 dollars
Direct Annual Cost =		$1,132,873	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,558	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$817,258	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$820,816	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,953,690	per year in 2019 dollars
NOx Removed =	469	tons/year
Cost Effectiveness =	$4,161	per ton of NOx removed in 2019 dollars

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Utility	**What type of fuel does the unit burn?**	Fuel Oil
Is the SNCR for a new boiler or retrofit of an existing boiler?	Retrofit		
Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.5	* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.	

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	384,917	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:	Not Applicable	
Enter the sulfur content (%S) =		percent by weight
or		
Select the appropriate SO_2 emission rate:	Not Applicable	
Ash content (%Ash):		percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

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Appendix - Table A-4a. Kahe K1 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.494	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.4	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

Original Submitted Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Original Submitted Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	384,917	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.8152	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.494	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.4	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Fuel ($Cost_{fuel}$)	13.01	\$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	\$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	\$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	\$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

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Appendix - Table A-4a. Kahe K1 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		384,917	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	19	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	84.65	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	177.09	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

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Appendix - Table A-4a. Kahe K1 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	201	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	694	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	92.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	31,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	26.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	158	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.63	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Original Submitted Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	903	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		384,917	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4184	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	19	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	84.65	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	177.09	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	201	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	694	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	92.7	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	31,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	26.0	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	158	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.63	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,639,022 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,714,103 in 2019 dollars
Total Capital Investment (TCI) =	$5,659,063 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,639,022 in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,714,103 in 2019 dollars

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Appendix - Table A-4a. Kahe K1 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$317,570	in 2019 dollars
Indirect Annual Costs (IDAC) =	$536,762	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$854,332	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$84,886	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$113,686	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$27,473	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,758	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$88,768	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$317,570	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,547	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$534,216	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$536,762	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$854,332	per year in 2019 dollars
NOx Removed =	177	tons/year
Cost Effectiveness =	$4,824	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,092,682	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,809,402	in 2019 dollars
Total Capital Investment (TCI) =	$3,772,708	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,092,682	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,809,402	in 2019 dollars

DOH-CAB Changed Spreadsheet

Appendix - Table A-4a. Kahe K1 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$289,275	in 2019 dollars
Indirect Annual Costs (IDAC) =	$261,260	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$550,535	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$56,591	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$113,686	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$27,473	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,758	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$88,768	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$289,275	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,698	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$259,562	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$261,260	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$550,535	per year in 2019 dollars
NOx Removed =	177	tons/year
Cost Effectiveness =	$3,109	per ton of NOx removed in 2019 dollars

DOH-CAB Changed Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	387,117	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Original Submitted Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.353	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.25	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent	
Fuel ($Cost_{fuel}$)	13.01	\$/MMBtu	Actual Data Used
Reagent ($Cost_{reag}$)	0.293	\$/gallon for a 29 percent solution of ammonia	Default Value Used
Water ($Cost_{water}$)	0.0042	\$/gallon	Default Value Used
Electricity ($Cost_{elect}$)	0.2521	\$/kWh	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton	

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

Maintenance and Administrative Charges Cost Factors:

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

Original Submitted Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Original Submitted Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	92	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	387,117	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	9.6957	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

DOH-CAB Changed Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.353	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.25	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent		
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu		Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia		Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon		Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh		Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

DOH-CAB Changed Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		387,117	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	29	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	91.51	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	192.53	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	142	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	490	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	65.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	22,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	18.6	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	112	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.15	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Original Submitted Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	892	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	805,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		387,117	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.97		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4208	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	29	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	91.51	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	192.53	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	142	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	490	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	65.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	22,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage:				
Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	18.6	kW/hour	
Water Usage:				
Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	112	gallons/hour	
Fuel Data:				
Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.15	MMBtu/hour	
Ash Disposal:				
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,630,607 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,739,588 in 2019 dollars
Total Capital Investment (TCI) =	$5,681,253 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,630,607 in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,739,588 in 2019 dollars

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$250,536	in 2019 dollars
Indirect Annual Costs (IDAC) =	$538,867	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$789,403	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$85,219	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$80,654	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$19,731	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,956	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$62,976	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$250,536	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,557	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$536,310	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$538,867	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$789,403	per year in 2019 dollars
NOx Removed =	193	tons/year
Cost Effectiveness =	$4,100	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

Appendix Table A-4b. Kahe K3 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,087,071	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,826,392	in 2019 dollars
Total Capital Investment (TCI) =	$3,787,502	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,087,071	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,826,392	in 2019 dollars

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Appendix Table A-4b. Kahe K3 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$222,130	in 2019 dollars
Indirect Annual Costs (IDAC) =	$262,285	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$484,414	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$56,813	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$80,654	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$19,731	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,956	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$62,976	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$222,130	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,704	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$260,580	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$262,285	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$484,414	per year in 2019 dollars
NOx Removed =	193	tons/year
Cost Effectiveness =	$2,516	per ton of NOx removed in 2019 dollars

DOH-CAB Changed Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	493,259	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.802	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.40	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI		CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent		
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu		Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia		Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon		Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh		Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

Original Submitted Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Original Submitted Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	493,259	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.3380	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.802	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.40	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index	
Annual Interest Rate (i)	3.25	Percent		
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu	Actual Data Used	
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia	Default Value Used	
Water ($Cost_{water}$)	0.0042	$/gallon	Default Value Used	
Electricity ($Cost_{elect}$)	0.2521	$/kWh	Actual Data Used	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

DOH-CAB Changed Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

DOH-CAB Changed Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		493,259	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.40	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	50	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	589.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,024.34	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	531	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,833	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	244.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	82,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	65.3	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	417	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	4.31	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Original Submitted Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,468	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		493,259	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.03		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.40	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3474	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	50	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	589.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,024.34	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	531	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,833	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	244.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	82,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	65.3	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	417	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	4.31	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,010,115	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,953,628	in 2019 dollars
Total Capital Investment (TCI) =	$7,752,866	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$2,010,115	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$3,953,628	in 2019 dollars

Original Submitted Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$623,223	in 2019 dollars
Indirect Annual Costs (IDAC) =	$735,359	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,358,582	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$116,293	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$249,165	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$57,167	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,044	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$194,553	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$623,223	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,489	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$731,871	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$735,359	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,358,582	per year in 2019 dollars
NOx Removed =	1,024	tons/year
Cost Effectiveness =	$1,326	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

Appendix Table A-4c. Kahe K5 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,340,077	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,635,752	in 2019 dollars
Total Capital Investment (TCI) =	$5,168,577	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,340,077	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,635,752	in 2019 dollars

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Appendix Table A-4c. Kahe K5 - SNCR Costing

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$584,458	in 2019 dollars
Indirect Annual Costs (IDAC) =	$357,924	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$942,382	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$77,529	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$249,165	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$57,167	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,044	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$194,553	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$584,458	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,326	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$355,598	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$357,924	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$942,382	per year in 2019 dollars
NOx Removed =	1,024	tons/year
Cost Effectiveness =	$920	per ton of NOx removed in 2019 dollars

DOH-CAB Changed Spreadsheet

Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	601,781	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Original Submitted Spreadsheet

Appendix Table A-4d. Kahe K6 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.196	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI		CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent		
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu		Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia		Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon		Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh		Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

Original Submitted Spreadsheet

Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Fuel Oil

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	142	MW
What is the higher heating value (HHV) of the fuel?	149,479	Btu/gallon
What is the estimated actual annual MWh output?	601,781	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.6761	MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.196	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Plant Elevation	10	Feet above sea level

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent		
Fuel ($Cost_{fuel}$)	13.01	$/MMBtu		Actual Data Used
Reagent ($Cost_{reag}$)	0.293	$/gallon for a 29 percent solution of ammonia		Default Value Used
Water ($Cost_{water}$)	0.0042	$/gallon		Default Value Used
Electricity ($Cost_{elect}$)	0.2521	$/kWh		Actual Data Used
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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

Maintenance and Administrative Charges Cost Factors:

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Data Sources and Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost ($/MMBtu)	13.01	2019 Average Fuel Cost	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	149,479	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

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Appendix Table A-4d. Kahe K6 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		601,781	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	24	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	69.96	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	148.25	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	134	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	463	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	61.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	20,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	16.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	105	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.09	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Appendix Table A-4d. Kahe K6 - SNCR Costing

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,516	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	1,243,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		601,781	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.07		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.48	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4238	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	24	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	69.96	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	148.25	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Reagent Data:

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	134	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	463	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	61.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	20,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	16.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	105	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	1.09	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,037,463	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,061,252	in 2019 dollars
Total Capital Investment (TCI) =	$6,628,329	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$2,037,463	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$3,061,252 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$255,122 in 2019 dollars
Indirect Annual Costs (IDAC) =	$628,697 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$883,819 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$99,425 in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$76,802 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$17,063 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$1,863 in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$59,969 in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0 in 2019 dollars
Direct Annual Cost =		$255,122 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,983 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$625,714 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$628,697 in 2019 dollars

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$883,819	per year in 2019 dollars
NOx Removed =	148	tons/year
Cost Effectiveness =	$5,962	per ton of NOx removed in 2019 dollars

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,358,309	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,040,834	in 2019 dollars
Total Capital Investment (TCI) =	$4,418,886	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,358,309	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,040,834 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$221,980 in 2019 dollars
Indirect Annual Costs (IDAC) =	$306,008 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$527,988 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.015 x TCI =	$66,283 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$76,802 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$17,063 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,863 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$59,969 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2019 dollars
Direct Annual Cost =		$221,980 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,988 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$304,019 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$306,008 in 2019 dollars

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Appendix Table A-4d. Kahe K6 - SNCR Costing

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$527,988 per year in 2019 dollars
NOx Removed =	148 tons/year
Cost Effectiveness =	$3,561 per ton of NOx removed in 2019 dollars

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Appendix Table A-1. CDS Capital and O&M Cost Estimate

Unit MW Rating (Nominal) Classification	K1 92 Fuel Oil	K2 90 Fuel Oil	K3 92 Fuel Oil	K4 93 Fuel Oil	K5 142 Fuel Oil	K6 142 Fuel Oil
Capital Cost						
Direct Costs						
Total Direct Costs (DC)	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 61,988,000	$ 61,988,000
Indirect Costs						
Summary of Indirect Costs not including Contingency	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 19,142,000	$ 19,142,000
Contingencies	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 21,468,000	$ 21,468,000
Total Indirect Costs (IC)	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 40,610,000	$ 40,610,000
Allowance for Funds Used During Construction (AFDC)	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 10,466,000	$ 10,466,000
Total Capital Investment (TCI)	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 113,064,000**	**$ 113,064,000**
Annual Cost						
Direct Annual Costs						
Fixed Annual Costs						
Maintenance labor and materials	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Total Fixed Annual Costs	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Variable Annual Costs						
Byproduct disposal	$ 273,000	$ 294,000	$ 377,000	$ 314,000	$ 478,000	$ 352,000
Reagent Cost (lime)	$ 632,000	$ 679,000	$ 864,000	$ 740,000	$ 1,582,000	$ 1,204,000
Water Cost	$ 51,000	$ 54,000	$ 69,000	$ 58,000	$ 116,000	$ 88,000
Power (ID and Aux) Cost	$ 1,561,000	$ 1,675,000	$ 2,151,000	$ 1,805,000	$ 4,259,000	$ 3,161,000
Total Variable Annual Costs	$ 2,517,000	$ 2,702,000	$ 3,461,000	$ 2,917,000	$ 6,435,000	$ 4,805,000
Total Direct Annual Costs (DAC)	$ 4,305,000	$ 4,490,000	$ 5,249,000	$ 4,705,000	$ 8,878,000	$ 7,248,000
Indirect Annual Costs						
Cost for capital recovery [2]	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 9,111,421	$ 9,111,421
Total Indirect Annual Costs (IDAC)	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 5,903,196	$ 9,111,421	$ 9,111,421
Total Annual Cost (TAC)	**$ 10,208,196**	**$ 10,393,196**	**$ 11,152,196**	**$ 10,608,196**	**$ 17,989,421**	**$ 16,359,421**
Total Annual Cost (TAC) - 2019 Dollars [3]	**$ 10,608,072**	**$ 10,800,319**	**$ 11,589,051**	**$ 11,023,741**	**$ 18,694,104**	**$ 17,000,254**

[1] Costing from an Hawaiian Electric internal study dated July 2012.

[2] Capital Recovery Factor (CRF) = [I x (1+i)^a]/[(1+i)^a - 1]   CRF = 0.08

Where:

I = Interest Rate (7% interest)

a = Equipment life (30 yrs)

[3] Cost scaled to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI) for 2012 (584.6) and 2019 (607.5). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

Original Submitted Spreadsheet

Appendix Table A-1. CDS Capital and O&M Cost Estimate (20 Yrs Life)

Unit MW Rating (Nominal) Classification	K1 92 Fuel Oil	K2 90 Fuel Oil	K3 92 Fuel Oil	K4 93 Fuel Oil	K5 142 Fuel Oil	K6 142 Fuel Oil
Capital Cost						
Direct Costs						
Total Direct Costs (DC)	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 61,988,000	$ 61,988,000
Indirect Costs						
Summary of Indirect Costs not including Contingency	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 19,142,000	$ 19,142,000
Contingencies	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 21,468,000	$ 21,468,000
Total Indirect Costs (IC)	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 40,610,000	$ 40,610,000
Allowance for Funds Used During Construction (AFDC)	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 10,466,000	$ 10,466,000
Total Capital Investment (TCI)	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 113,064,000**	**$ 113,064,000**
Annual Cost						
Direct Annual Costs						
Fixed Annual Costs						
Maintenance labor and materials	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Total Fixed Annual Costs	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Variable Annual Costs						
Byproduct disposal	$ 273,000	$ 294,000	$ 377,000	$ 314,000	$ 478,000	$ 352,000
Reagent Cost (lime)	$ 632,000	$ 679,000	$ 864,000	$ 740,000	$ 1,582,000	$ 1,204,000
Water Cost	$ 51,000	$ 54,000	$ 69,000	$ 58,000	$ 116,000	$ 88,000
Power (ID and Aux) Cost	$ 1,561,000	$ 1,675,000	$ 2,151,000	$ 1,805,000	$ 4,259,000	$ 3,161,000
Total Variable Annual Costs	$ 2,517,000	$ 2,702,000	$ 3,461,000	$ 2,917,000	$ 6,435,000	$ 4,805,000
Total Direct Annual Costs (DAC)	$ 4,305,000	$ 4,490,000	$ 5,249,000	$ 4,705,000	$ 8,878,000	$ 7,248,000
Indirect Annual Costs						
Cost for capital recovery [2]	$ 5,038,260	$ 5,038,260	$ 5,038,260	$ 5,038,260	$ 7,776,416	$ 7,776,416
Total Indirect Annual Costs (IDAC)	$ 5,038,260	$ 5,038,260	$ 5,038,260	$ 5,038,260	$ 7,776,416	$ 7,776,416
Total Annual Cost (TAC)	**$ 9,343,260**	**$ 9,528,260**	**$ 10,287,260**	**$ 9,743,260**	**$ 16,654,416**	**$ 15,024,416**
Total Annual Cost (TAC) - 2019 Dollars [3]	**$ 9,709,255**	**$ 9,901,501**	**$ 10,690,233**	**$ 10,124,923**	**$ 17,306,804**	**$ 15,612,953**

[1] Costing from an Hawaiian Electric internal study dated July 2012.

[2] Capital Recovery Factor (CRF) = [I x (1+i)^a]/[(1+i)^a - 1]   CRF = 0.07

Where:

I = Interest Rate (3.25% interest)

a = Equipment life (20 yrs)

[3] Cost scaled to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI) for 2012 (584.6) and 2019 (607.5). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

DOH-CAB Changed Spreadsheet (20 Yrs Life)

Appendix Table A-1. CDS Capital and O&M Cost Estimate (30 Yrs Life)

Unit MW Rating (Nominal) Classification	K1 92 Fuel Oil	K2 90 Fuel Oil	K3 92 Fuel Oil	K4 93 Fuel Oil	K5 142 Fuel Oil	K6 142 Fuel Oil
Capital Cost						
Direct Costs						
Total Direct Costs (DC)	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 40,161,000	$ 61,988,000	$ 61,988,000
Indirect Costs						
Summary of Indirect Costs not including Contingency	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 12,402,000	$ 19,142,000	$ 19,142,000
Contingencies	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 13,909,000	$ 21,468,000	$ 21,468,000
Total Indirect Costs (IC)	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 26,311,000	$ 40,610,000	$ 40,610,000
Allowance for Funds Used During Construction (AFDC)	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 6,781,000	$ 10,466,000	$ 10,466,000
Total Capital Investment (TCI)	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 73,253,000**	**$ 113,064,000**	**$ 113,064,000**
Annual Cost						
Direct Annual Costs						
Fixed Annual Costs						
Maintenance labor and materials	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Total Fixed Annual Costs	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 1,788,000	$ 2,443,000	$ 2,443,000
Variable Annual Costs						
Byproduct disposal	$ 273,000	$ 294,000	$ 377,000	$ 314,000	$ 478,000	$ 352,000
Reagent Cost (lime)	$ 632,000	$ 679,000	$ 864,000	$ 740,000	$ 1,582,000	$ 1,204,000
Water Cost	$ 51,000	$ 54,000	$ 69,000	$ 58,000	$ 116,000	$ 88,000
Power (ID and Aux) Cost	$ 1,561,000	$ 1,675,000	$ 2,151,000	$ 1,805,000	$ 4,259,000	$ 3,161,000
Total Variable Annual Costs	$ 2,517,000	$ 2,702,000	$ 3,461,000	$ 2,917,000	$ 6,435,000	$ 4,805,000
Total Direct Annual Costs (DAC)	$ 4,305,000	$ 4,490,000	$ 5,249,000	$ 4,705,000	$ 8,878,000	$ 7,248,000
Indirect Annual Costs						
Cost for capital recovery [2]	$ 3,859,094	$ 3,859,094	$ 3,859,094	$ 3,859,094	$ 5,956,406	$ 5,956,406
Total Indirect Annual Costs (IDAC)	$ 3,859,094	$ 3,859,094	$ 3,859,094	$ 3,859,094	$ 5,956,406	$ 5,956,406
Total Annual Cost (TAC)	**$ 8,164,094**	**$ 8,349,094**	**$ 9,108,094**	**$ 8,564,094**	**$ 14,834,406**	**$ 13,204,406**
Total Annual Cost (TAC) - 2019 Dollars [3]	**$ 8,483,898**	**$ 8,676,145**	**$ 9,464,877**	**$ 8,899,567**	**$ 15,415,500**	**$ 13,721,650**

[1] Costing from an Hawaiian Electric internal study dated July 2012.

[2] Capital Recovery Factor (CRF) = [I x (1+i)^a]/[(1+i)^a - 1]   CRF = 0.05

Where:

I = Interest Rate (3.25% interest)

a = Equipment life (30yrs)

[3] Cost scaled to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI) for 2012 (584.6) and 2019 (607.5). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

DOH-CAB Changed Spreadsheet (30 Yrs Life)

Appendix Table A-2. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	K1	K2	K3	K4	K5
Boiler design capacity, mmBtu/hr (C)		903	900	892	918	1468
Boiler Type		Normal	Normal	Tangential	Tangential	Normal
2017 Annual Heat Input, MMBtu/yr (H)		3,778,041	2,959,869	3,753,356	3,858,826	5,099,323
Unit Size, kW (kW)		92,000	90,000	92,000	93,000	142,000
Unit Size, MW (MW)		92.0	90.0	92.0	93.0	142.0
Capital recovery factor						
a. Equipment CRF, 30-yr life, 7% interest	= [I x (1+i)^a]/[(1+i)^a - 1] where I = interest rate, a = equipment life	0.08	0.08	0.08	0.08	0.08
Cost Index (CI) [A]						
a. 2019	607.5					
b. 2004	444.2					
Total Capital Investment [B,C]						
TCI ($)	=$24/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall =$18/kW x kW x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$4,615,869	$4,551,295	$3,461,902	$3,485,976	$6,096,525
Direct Annual Operating Costs $/yr						
Variable O&M Costs [D]	=($0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Wall $0.03 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2018}/CI_{2004}) - Tangential	$41,336	$32,384	$15,400	$15,832	$55,792
Indirect Annual Costs, $/yr						
1. Fixed O&M Costs [E]	= $0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Wall = $0.27/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2018}/CI_{2004}) - Tangential	$69,238	$68,269	$51,929	$52,290	$91,448
2. Capital recovery	= Equipment CRF x TCI	$371,976	$366,772	$278,982	$280,922	$491,297
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$482,550**	**$467,426**	**$346,310**	**$349,044**	**$638,537**

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region,* dated September 6, 2005. The cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

[A] Cost Index: Chemical Engineering Plant Cost Index (CEPCI). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

[B] TCI for LNB and LNB w/over fire air ranges from $6/kW to $24/kW for wall boilers and $10/kW to $18/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO_X control.

[C] Scaling factor = (300/Nameplate capacity)^0.359

[D] The variable O&M costs for LNB and LNB w/over fire air ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr for wall boilers and 0.027 mills/kW-hr to 0.03 mills/kW-hr for tangential boilers, the high end of the range was used due to Hawai'i's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO_X control.

[E] The fixed O&M costs for LNB and LNB w/over fire air ranges from $0.09/kW to $0.36/kW for wall boilers and $0.15/kW to $0.27/kW for tangential boilers, the high end of the range was used due to Hawai'i's remote location.

Original Submitted Spreadsheet

Appendix Table A-2. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	K1	K2	K3	K4	K5
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Boiler Type		Normal	Normal	Tangential	Tangential	Normal
2017 Annual Heat Input, MMBtu/yr (H)		3,778,041	2,959,869	3,753,356	3,858,826	5,099,323
Unit Size, kW (kW)		92,000	90,000	92,000	93,000	142,000
Unit Size, MW (MW)		92.0	90.0	92.0	93.0	142.0
Capital recovery factor						
a. Equipment CRF, 20-yr life, 3.25% interest	= [I x (1+i)^a]/[(1+i)^a - 1] where I = interest rate, a = equipment life	0.07	0.07	0.07	0.07	0.07
Cost Index (CI) [A]						
a. 2019	607.5					
b. 2004	444.2					
Total Capital Investment [B,C]						
TCI ($)	=$24/kW x kW x (300/MW)^0.359 x (CI_{2019}/CI_{2004}) - Wall =$18/kW x kW x (300/MW)^0.359 x (CI_{2019}/CI_{2004}) - Tangential	$4,615,869	$4,551,295	$3,461,902	$3,485,976	$6,096,525
Direct Annual Operating Costs $/yr						
Variable O&M Costs [D]	=($0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2019}/CI_{2004}) - Wall $0.03 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x (CI_{2019}/CI_{2004}) - Tangential	$41,336	$32,384	$15,400	$15,832	$55,792
Indirect Annual Costs, $/yr						
1. Fixed O&M Costs [E]	= $0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2019}/CI_{2004}) - Wall = $0.27/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x (CI_{2019}/CI_{2004}) - Tangential	$69,238	$68,269	$51,929	$52,290	$91,448
2. Capital recovery	= Equipment CRF x TCI	$317,474	$313,033	$238,106	$239,762	$419,312
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$428,048**	**$413,686**	**$305,434**	**$307,883**	**$566,552**

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP*

[A] Cost Index: Chemical Engineering Plant Cost Index (CEPCI). As published in Chemical Engineering Magazine - Revision: 18, Apr 16, 2019 and https://www.chemengonline.com/2019-chemical-

[B] TCI for LNB and LNB w/over fire air ranges from $6/kW to $24/kW for wall boilers and $10/kW to $18/kW for tangential boilers, the high end of the range was used due to Hawaiʻi's remote

[C] Scaling factor = (300/Nameplate capacity)^0.359

[D] The variable O&M costs for LNB and LNB w/over fire air ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr for wall boilers and 0.027 mills/kW-hr to 0.03 mills/kW-hr for tangential boilers, the

[E] The fixed O&M costs for LNB and LNB w/over fire air ranges from $0.09/kW to $0.36/kW for wall boilers and $0.15/kW to $0.27/kW for tangential boilers, the high end of the range was used

DOH-CAB Changed Spreadsheet

Final Conclusion and Action

The control cost summarized in the table below were based on a four-factor analyses of the Hawaiian Electric Kahe Power Plant after the facility was initially identified with Q/d to significantly affect visibility in the national parks. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLMs. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. Costs for scrubbers that are highlighted in blue were based on a remaining useful life of thirty (30) years. An SCR retrofit factor of 1.0 was used instead of 1.5. A 3.25% prime interest rate was used versus a 7% interest rate.

<table>
<tr><th colspan="4">Table D. Four-Factor Analysis for Hawaiian Electric Kahe Power Plant Oahu</th></tr>
<tr><th>Unit</th><th>Description</th><th>Primary Fuel</th><th>Control Measures & Cost per Ton [a,b,c,d,e]</th></tr>
<tr><td>K-1</td><td>92 MW Boiler</td><td>Fuel Oil No. 6 with 0.5% maximum sulfur content</td><td rowspan="4">Fuel switch to residual/ULSD fuel blend with 0.25% maximum sulfur content - $13,250/ton SO_2 for K1 to K6
Fuel switch to ULSD with 0.0015% maximum sulfur content - $11,711/ton SO_2 for K1 to K6
Fuel switch to ULSD with 0.0015% sulfur content - $7,594/ton SO_2, NO_X, and PM_{10} combined for K1
Fuel switch to ULSD with 0.0015% sulfur content - $6,900/ton SO_2, NO_X, and PM_{10} combined for K2
Fuel switch to ULSD with 0.0015% sulfur content - $9,780/ton SO_2, NO_X, and PM_{10} combined for K3
Fuel switch to ULSD with 0.0015% sulfur content - $9,697/ton SO_2, NO_X, and PM_{10} combined for K4
Fuel switch to ULSD with 0.0015% sulfur content - $6,308/ton SO_2, NO_X, and PM_{10} combined for K5
Fuel switch to ULSD with 0.0015% sulfur content - $9,707/ton SO_2, NO_X, and PM_{10} combined for K6
CDS for K-1 - $14,002 ($12,815) **($11,198)**/ton SO_2
CDS for K-2 - $18,196 ($16,682) **($14,617)**/ton SO_2
CDS for K-3 - $15,397 ($14,203) **($12,575)**/ton SO_2
CDS for K-4 - $14,246 ($13,084) **($11,501)**/ton SO_2
CDS for K-5 - $18,281 ($16,925) **($15,075)**/ton SO_2
CDS for K-6 - $13,195 ($12,119) **($10,651)**/ton SO_2
LNB w/OFA/FGR for K-1 - $1,318 ($1,170)/ton NO_X
LNB w/OFA/FGR for K-2 - $901 ($797)/ton NO_X
LNB w/OFA/FGR for K-3 - $1,209 ($1,067)/ton NO_X
LNB w/OFA/FGR for K-4 - $1,008 ($889)/ton NO_X
LNB w/OFA/FGR for K-5 - $499 ($443)/ton NO_X
SCR for K-1 - $2,972 ($1,864)/ton NO_X
SCR for K-2 - $2,557 ($1,561)/ton NO_X
SCR for K-3 - $4,581 ($2,842)/ton NO_X
SCR for K-4 - $4,085 ($2,546)/ton NO_X
SCR for K-5 - $1,709 ($1,100)/ton NO_X
SCR for K-6 - $6,488 ($4,161)/ton NO_X
SCR+Combustion Controls for K-1 - $3,213 ($2,165)/ton NO_X
SCR+Combustion Controls for K-2 - $2,870 ($1,896)/ton NO_X
SCR+Combustion Controls for K-3 - $4,434 ($2,910)/ton NO_X</td></tr>
<tr><td>K-2</td><td>90 MW Boiler</td><td>Fuel Oil No. 6 with 0.5% maximum sulfur content</td></tr>
<tr><td>K-3</td><td>92 MW Boiler</td><td>Fuel Oil No. 6 with 0.5% maximum sulfur content</td></tr>
<tr><td>K-4</td><td>93 MW Boiler</td><td>Fuel Oil No. 6 with 0.5% maximum sulfur content</td></tr>
</table>

Table D. Four-Factor Analysis for Hawaiian Electric Kahe Power Plant Oahu			
Unit	**Description**	**Primary Fuel**	**Control Measures & Cost per Ton** [a,b,c,d,e]
K-5	142 MW Boiler	Fuel Oil No. 6 with 0.5% maximum sulfur content	SCR+Combustion Controls for K-4 - $4,014 ($2,644)/ton NO_X SCR+Combustion Controls for K-5 - $1,929 ($1,322)/ton NO_X SNCR for K-1 - $4,824 ($3,109)/ton NO_X SNCR for K-2 - $2,303 ($1,484)/ton NO_X SNCR for K-3 - $4,100 ($2,516)/ton NO_X SNCR for K-4 - $3,160 ($1,939)/ton NO_X SNCR for K-5 - $1,326 ($920)/ton NO_X SNCR for K-6 - $5,962 ($3,561)/ton NO_X
K-6	142 MW Boiler	Fuel Oil No. 6 with 0.5% maximum sulfur content	SNCR+Combustion Controls for K-1 - $2,409 ($1,764)/ton NO_X SNCR+Combustion Controls for K-2 - $1,982 ($1,446)/ton NO_X SNCR+Combustion Controls for K-3 - $2,987 ($2,077)/ton NO_X SNCR+Combustion Controls for K-4 - $2,571 ($1,789)/ton NO_X

a. CDS-circulating dry scrubber, LNB-low NO_X burner, MW-megawatt, OFA-overfire air, SCR-selective catalytic reduction, SNCR-selective noncatalytic reduction, ULSD-ultra-low sulfur diesel, and combustion controls are LNB with OFA and/or FGR.

b. For particulate control, the Kahe boilers are subject to a filterable PM standard of 0.030 lb/MMBtu on a thirty-boiler operating day rolling average for non-continental liquid oil-fired units in accordance with EGU MACT standards 40 CFR, Part 63, Subpart UUUUU.

c. Annual SNCR cost for Kahe Boiler K1 was used to determine the cost per ton of NO_X removed by SNCR for Kahe Boiler K2.

d. Annual SNCR cost for Kahe Boiler K3 was used to determine the cost per ton of NO_X removed by SNCR for Kahe Boiler K4.

e. According to the four-factor analysis, it is unknown if LNB alone can achieve a controlled NO_X emission level of 0.30 lb/MMBtu for K1, K2, and K5 and 0.20 lb/MMBtu for K3 and K4. Therefore, costing is based on a range of costs cost for LNB with OFA. The cost of FGR and LNB with FGR are expected to be covered by this range and have similar NO_X control.

Due to the low relative potential of the Hawaiian Electric Kahe Power Plant to contribute to visibility impairment at the Class I Areas as identified in the WEP/AOI analysis after initial Q/d screening, control measures identified in the four-factor analysis to be cost effective are not required. Note that prevailing trade winds transport pollutants from point sources on Oahu located down-wind of the Class I Areas a majority of the time. Unlike Q/d, the more sophisticated WEP/AOI analysis inherently accounts for meteorological data, such as wind patterns, and the specific light extinction contribution of each particle species.