Appendix G: Regional Haze Four-Factor Analysis
Hawaiian Electric Company, Inc.
Kanoelehua-Hill Generating Station

Initial Four – Factor Analysis

REGIONAL HAZE FOUR-FACTOR ANALYSIS
Kanoelehua-Hill Generating Station

Hawaiian
Electric

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1. EXECUTIVE SUMMARY

The State of Hawaiʻi has two Class I areas (National Parks) that trigger compliance with the Regional Haze Rule (RHR); Hawaiʻi's Mandatory Federal Class I Areas are Haleakalā National Park on Maui Island and Hawaiʻi Volcanoes National Park on the Hawaiʻi Island. This report documents the results of the Regional Haze Rule (RHR) second planning period four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric[1] for the two boilers (Hill 5 and Hill 6), one combustion turbine (CT-1), and four diesel engines (D-11, D-15, D-16, and D-17) at the Kanoelehua-Hill Generating Station (Kanoelehua-Hill). Hill 5 is a 14 megawatt (MW) wall-fired boiler, and Hill 6 is a 21 MW tangentially-fired boiler. Both boilers currently burn residual oil. CT-1 is 11.6 MW simple cycle combustion turbine that currently burns diesel. D-11 is a 2 MW diesel engine generator, and D-15, D-16, and D-17 are 2.75 MW diesel engine generators. All the diesel engine generators currently burn ultra-low sulfur diesel (ULSD). 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 the potential to show reasonable progress towards the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period Best Available Retrofit Technology (BART) five-factor analysis for Kanoelehua-Hill. Other long-term emission reduction strategies, such as those included as part of Hawaiʻi's Renewable Portfolio Standards (RPS), are viable alternatives to emission 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 that apply in Hawaiʻi that should be given consideration in 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 actual Regional Haze 2064 target date. These same issues were addressed by the EPA in the Federal Implementation Plan (FIP) and the State of Hawaiʻi Department of Health in their 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, Hawaiian Electric does not propose any emissions reduction measures in addition to its RPS program to meet the RHR requirements.

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[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. BACKGROUND AND ADDITIONAL FACTORS

2.1. REGIONAL HAZE RULE BACKGROUND

In the 1977 amendments to the federal Clean Air Act (CAA), the U.S. 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 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 established an emissions cap of 3,550 tons of 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 ensure that reasonable progress is made during

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[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.

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 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. 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.*

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 and the development of Hawaiʻi's RHR State Implementation Plan (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 area. The WRAP Guidance itself states that EPA has concerns over only relying on the Q/d method for

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[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, EPA-454/R-18-010, December 2018.

[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 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 Hawaiʻi Electric Light that its Kanoelehua-Hill Generating Station was identified, based on the Q/d analysis, 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.

The SIP Guidance requires that the selection of controls necessary to make reasonable progress must consider the five required factors listed in section 51.308(f)(2)(iv), and other factors that are reasonable to consider. Hawaiian Electric and AECOM prepared summary, included in Section 2.2, which describes special circumstances that apply 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 its 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 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 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 Kanoelehua-Hill. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_X controls to be material.

2.2.2. Contribution to Visibility Impairment from Volcanic Activity

Volcanic activity on the Hawaiʻi Island represents a unique challenge to understanding haze in Hawai'i 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. It should also be noted that

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[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).

volcanic activity on Hawaiʻi Island is the largest source of NO_X in the state. Nitrate haze is a very small component in Hawaiʻi's Class I areas, which is expected given the nitrate chemistry as explained in Appendix B to this report. Direct particulate matter (PM) emissions constitute a very small portion of haze and significant portions are due to volcanic emissions as explained in Appendix B to this report. Visibility improvements made from significant reductions of point source SO_2 in Maui and Hawaiʻi Island is obscured by sulfate from natural volcanic SO_2 that overwhelms sulfate from anthropogenic SO_2 sources. Anthropogenic sources (from power plants) are projected to be phased out well before the end point of the Regional Haze Rule (i.e., 2064) by Hawaiʻi's State Law: Renewable Portfolio Standards (RPS). Thus, the DOH should limit the haze precursors control evaluations solely to SO_2 for the Second Decadal Review for Kanoelehua-Hill.

2.2.3. Renewable Portfolio Standards

Based on AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO_2, NO_X, and PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill 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 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 Hawaii 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. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO_2 emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 Kanoelehua-Hill.

Table 3-1. Baseline SO_2 Emissions

		SO_2 Emissions	
Unit	**Fuel Sulfur** [A]	**(lb/MMBtu)** [B]	**(TPY)** [C]
Hill 5	1.69%	1.87	820.6
Hill 6	1.69%	1.87	1,346.6
D-11	0.0004%	4.10E-04	<0.1
D-15	0.0004%	4.10E-04	<0.1
D-16	0.0004%	4.10E-04	<0.1
D-17	0.0004%	4.10E-04	<0.1
CT-1	0.0540%	5.51E-02	<0.1
		Total	**2,167.2**

[A] Calendar year 2017 annual average residual oil sulfur content.

[B] The SO_2 emission factors are based on 100% conversion of fuel sulfur to SO_2 and the calendar year 2017 annual average fuel density (8.33 lb/gal for residual oil; 7.10 lb/gal for ULSD; 6.96 lb/gal for diesel) and higher heating value (150,985 Btu/gal for residual oil; 138,564 Btu/gal for ULSD; 136,533 Btu/gal for diesel).

[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 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.

Because, diesel engine generators D-11, D-15, D-16, and D-17 currently burn ULSD, and a four-factor analysis is not required for SO_2.

CT-1 operates on a very limited basis and post-combustion SO_2 controls are not feasible for combustion turbines. Therefore, fuel switching to ULSD is the only feasible option to reduce SO_2 emissions.

3.1.1. Post-Combustion Controls

FGD applications have not been used historically for SO_2 control on oil-fired boilers the size of those operated at the Kanoelehua-Hill Generating Station. As there are no known FGD applications for similar oil-fired boilers, the performance of FGDs on oil-fired boilers is unknown. The EPA took this into account when evaluating the Best Available Retrofit Technology (BART) presumptive SO_2 emission rate for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD[8]. Since there are no applications of FGD on oil-fired boilers in the U.S., FGDs are considered technically infeasible for the control of SO_2 from the Hill boilers.

3.1.2. Fuel Switching

The Hill boilers currently burn residual high sulfur fuel oil with a maximum sulfur content of 2.0 percent by weight. The average sulfur content of the residual high sulfur fuel oil purchased in 2017 was approximately 1.69 percent by weight. Switching to a lower sulfur fuel would reduce SO_2 emissions in proportion to the reduction in fuel sulfur content.[9]

On Oahu, 0.5 percent by weight low sulfur fuel oil is produced and is used at Hawaiian Electric's Kahe and Waiau Generating Stations on Oahu, However, is not a technically feasible option for the Hill boilers. This low sulfur fuel oil has a higher viscosity and pour point than the residual high sulfur fuel oil used by the Hill boilers and the current fuel supply chain from Oahu to the Hill boilers cannot support this quality of fuel that is semi-solid at ambient temperatures. For the low sulfur fuel oil to be burned by the Hill boilers, the piping and tanks that are used to transport and store the oil would need to be heated, at a cost of 500 thousand dollars ($500,000) to 1 million dollars ($1,000,000), which is not economically feasible because of the very limited remaining time that oil will be burned by the Hill boilers. There are, however, technically feasible options which include blending the current residual high 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.

CT-1 is currently permitted to burn diesel with a maximum sulfur content of 0.4 percent by weight. The average sulfur content of the diesel purchased in 2017 was approximately 0.054 percent by weight. Due to the limited operations of CT-1, 2017 emissions were less than 0.1 tons of $SO_{2,}$ and any reduction in fuel sulfur content is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-1.

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 Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (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 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 Hawaii Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these

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[8] *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

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

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, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only technically feasible option to reduce SO_2 emissions for the Hill 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 switching the Hill boilers to a lower sulfur residual/distillate blended fuel, or a lower sulfur diesel are discussed in the following sections.

3.2.1. Cost of Compliance

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.

Kanoelehua-Hill currently purchases residual high sulfur fuel oil from Par Hawaii Refining, LLC; current fuel costs were obtained from 2019 actual fuel purchases. The fuels are refined on Oahu, and changes in quantities of residual high sulfur fuel oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance.

Table 3-2 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 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 high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight is $7,422 per ton SO_2 and would increase fuel cost 7 million dollars ($7,000,000) annually and 105 million dollars ($105,000,0000) over fifteen (15) years.

Table 3-3 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to distillate fuel with a maximum sulfur content of 0.4 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 distillate fuel with a maximum sulfur content of 0.4 percent by weight is $6,921 per ton SO_2 and would increase fuel cost 11.7 million dollars ($11,700,000) annually and 175.5 million dollars ($175,500,000) over fifteen (15) years.

3.2.2. Time Necessary to Achieve Compliance

If the DOH determines that switching from residual high sulfur fuel oil to a residual high sulfur fuel oil /distillate blended fuel or a lower sulfur diesel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

Table 3-2. SO_2 Cost Effectiveness of Switching to a Residual/Distillate Blended Fuel

	Current Residual Oil [A]					Residual/Distillate Blend (1.0% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	141,953	6,188,253	462.06	358.54	0.43	2,660,949	7,422
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	141,953	10,154,888	758.24	588.36	0.43	4,366,602	7,422

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

[B] Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted averge of the 2017 fuel HHV and density and contract fuel sulur limits (2.0% for residual oil and 0.4% for diesel).

[C] Based on actual 2019 fuel purchases by Hawai‘i Electric Light.

Table 3-3. SO_2 Cost Effectiveness of Switching to Distillate Fuel

	Current Residual Oil [A]					Diesel (0.4% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	136,533	6,433,896	179.20	641.40	0.69	4,439,388	6,921
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	136,533	10,557,987	294.07	1,052.53	0.69	7,285,011	6,921

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

[B] Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).

[C] Based on actual 2019 fuel purchases by Hawai‘i Electric Light.

3.2.3. Energy and Non-Air Quality Environmental Impacts

There are no energy and non-air quality environmental impacts 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 Kanoelehua-Hill. This increase will impact the price of electricity for Hawaiian Electric customers because it will not only increase the cost of electricity produced by Kanoelehua-Hill, but it will also increase the cost of electricity that Hawaiian Electric purchases from independent power producers (IPPs). The contracts with the IPPs are tied to Hawaiian Electric's "avoided cost" of producing electricity. Thus, as Hawaiian Electric's fuel costs increase for Kanoelehua-Hill, the price that the IPPs receive for the electricity they provide increases. As a result, the costs of all electricity sources on Hawaiʻi Island increase as Hawaiian Electric's fuel costs increase.

3.2.4. Remaining Useful Life

The cost of compliance does not contain any capital cost. Therefore, the remaining useful lives of the Hill boilers are not needed to annualize the capital cost. However, Hawaiian Electric intends to retire the Hill 5 and Hill 6 boilers after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% which is necessary to meet Hawaiʻi's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements 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 to a residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight is $7,400 per ton SO_2 and would increase fuel cost 7 million dollars ($7,000,000) annually and 105 million dollars ($105,000,0000) over fifteen (15) years. The cost effectiveness of switching to a distillate fuel with a maximum sulfur content of 0.4 percent by weight is $6,900 per ton SO_2 and would increase fuel cost 11.7 million dollars ($11,700,000) annually and 175.5 million dollars ($175,500,000) 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.[11]

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

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[11] *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.

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_X emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 Kanoelehua-Hill.

Table 4-1. Baseline NO_X Emissions

	NO_X Emissions		
Unit	**Primary Fuel Emissions Factor (lb/MMBtu)** [A]	**Adjusted Emission Factor (lb/MMBtu)** [B]	**(TPY)** [C]
Hill 5	0.572	0.573	251.5
Hill 6	0.490	0.491	353.6
D-11	3.200	--	0.4
D-15	3.200	--	1.9
D-16	3.200	--	0.7
D-17	3.200	--	1.0
CT-1	0.880	--	0.3
		Total	**609.3**

[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).

D-11, D-15, D-16, D-17, and CT-1 operate on a very limited basis. Total 2017 NO_X emissions from these units were less than five (5) tons, and any reductions in NO_X emissions are expected to have a negligible impact on regional haze reasonable progress. Therefore, the four-factor analysis was not conducted for D-11, D-15, D-16, D-17, and CT-1.

4.1. NITROGEN OXIDES CONTROL OPTIONS

The characterization of emission controls available and potentially applicable to the source is a necessary step before the four-factors can be analyzed. NO_X emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e., fuel versus combustion air) has led to the use of the terms "thermal NO_X" and "fuel NO_X." 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. NO_X emissions from residual oil can be up to fifty percent fuel NO_X.[12]

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 the form of nitrogen dioxide (NO_2). The NO_2/NO_X in-stack ratio for boilers is typically less than ten percent.

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

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. 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
  - Flue Gas Recirculation (FGR)
  - Overfire Air (OFA)
  - Low NO_X Burners (LNB)
- Post-Combustion Controls
  - 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 operated without additional controls, the NO_X control range for wall-fired boilers (Hill 5) with FGR is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[13] This control is a technically feasible option for the Hill 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. OFA as a single NO_X control technique results in estimated NO_X emissions for wall-fired boilers (Hill 5) is approximately 0.30-0.45 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.20-0.30 lb/MMBtu.[14] This control is a technically feasible option for the Hill 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

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

[14] 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 (Hill 5) is approximately 0.25-0.35 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[15] When combined with OFA, the estimated NO_X control range on wall-fired boilers (Hill 5) is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[16] LNB systems are technically feasible for the Hill 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 (Hill 5), and for tangentially-fired boilers (Hill 6) is approximately 0.03-0.10 lb/MMBtu.[17] This control is a technically feasible option for the Hill 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 (Hill 5) is approximately 0.30-0.40 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.20-0.25 lb/MMBtu.[18] This control is a technically feasible option for the Hill boilers.

4.1.3. Rank of Technically Feasible NO_X 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.

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[15] Ibid.

[16] Ibid.

[17] Ibid.

[18] 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 Hill boilers based on the application of the controls listed in Table 4-2 is unknown. Based on several discussions between Trinity and a firm that designs LNB combustion systems, it is believed that combustion controls such as LNB and possibly LNB in combination with OFA or FGR can achieve a NO_X emissions level of approximately 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively. As noted in Table 4-1, the Hill boilers are currently emitting in the range of 0.49 lb/MMBtu to 0.57 lb/MMBtu. Further, it is believed that SCR can achieve a NO_X emissions level of approximately 0.10 lb/MMBtu.

4.1.4. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_X emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (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 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 Hawaii 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.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, LNB and SCR are the best feasible option to reduce NO_X emissions. 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 LNB and SCR 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. The cost effectiveness of LNB with OFA is based on a controlled NO_X emissions level of 0.30 lb/MMBtu and 0.18 lb/MMBtu for Hill 5 and Hill 6, respectively. At this time, it is unknown if LNBs 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 LNB with OFA, it is assumed that a NO_X emissions level of 0.30 lb/MMBtu and 0.18 lb/MMBtu for Hill 5 and Hill 6, respectively, can be achieved with LNB with OFA. As the level of NO_X emissions is comparable to SNCR combustion controls, the only add-on control that would be expected to result in lower achievable NO_X emissions rates than combustion controls is SCR.

The cost effectiveness of SCR is based on a controlled NO_X emissions level of 0.10 lb/MMBtu. The SCR costing is based on generic EPA control costing[19] which does not consider Hawaiʻi's remote location which results in additional shipping and higher construction cost. To account for these higher costs, a Hawaiʻi Island construction cost multiplier[20] of 1.840 was applied to the capital SCR cost.

Table 4-3 presents a summary of the cost effectiveness of adding LNB with OFA and SCR. 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 $870 per ton to $1,515 per ton of NO_X and the total cost equals 400 thousand dollars ($400,000) annually and 6 million dollars ($6,000,000) over fifteen (15) years. The cost effectiveness of SCR ranges from $5,040 per ton to $5,200 per ton of NO_X and the total cost equals 2.5 million dollars ($2,500,000) annually and 37.5 million dollars ($37,500,000) over fifteen (15) years.

The cost of compliance assumes that the capital costs will be amortized over fifteen (15) years. However, Hawaiian Electric intends to retire the Hill 5 and Hill 6 boilers after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawaiʻi's statutory requirement to use no fossil fuel for electric generation by 2045. This means that the amortization period may be less than fifteen (15) years, and the cost of controls will be higher.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years.

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[19] Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance, Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS. Docket ID No. EPA-HQ-OAR-2015-0500, November 2015.

[20] The Maui construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016* to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead.

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)
Hill 5	LNB+OFA	251.5	0.30	878,441	131.8	119.7	181,393	1,515
	SCR	251.5	0.10	878,441	43.9	207.6	1,046,288	5,040
Hill 6	LNB+OFA	353.6	0.20	1,441,517	144.2	209.4	182,245	870
	SCR	353.6	0.10	1,441,517	72.1	281.5	1,463,862	5,200

[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.

4.2.3. 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 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 Hill 5 and Hill 6 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, for this four-factor analysis. However, Hawaiian Electric intends to retire the Hill 5 and Hill 6 boilers after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawai‘i’s statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements 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 LNB with OFA ranges from $900 per ton to $1,500 per ton of NO_X and the total cost equals 400 thousand dollars ($400,000) annually and 6 million dollars ($6,000,000) over fifteen (15) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, EPA concluded the emission reductions provided by LNB are unlikely to provide a measurable visibility benefit at Hawai‘i Volcanoes National Park or Haleakalā National Park.[23]

The cost effectiveness of SCR ranges from $5,000 per ton to $5,200 per ton of NO_X and the total cost equals 2.5 million dollars ($2,500,000) annually and 37.5 million dollars ($37,500,000) over fifteen (15) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.[24]

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Additionally, reductions in NO_X emissions are expected to have a negligible impact on regional haze. Therefore, Hawaiian Electric does not propose any NO_X emissions reductions in addition to its RPS program to meet the RHR requirements.

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[23] *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai‘i*, U.S. EPA Region 9, May 14, 2012.

[24] Ibid.

5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 Kanoelehua-Hill.

Table 5-1. Baseline PM_{10} Emissions

	PM_{10} Emissions		
Unit	**Primary Fuel Emissions Factor (lb/MMBtu)** [A]	**Adjusted Emission Factor (lb/MMBtu)** [B]	**(TPY)** [C]
Hill 5	0.0562	0.0562	24.7
Hill 6	0.0449	0.0450	32.4
D-11	0.0573	--	<0.1
D-15	0.0573	--	<0.1
D-16	0.0573	--	<0.1
D-17	0.0573	--	<0.1
CT-1	0.0113	--	<0.1
		Total	**57.2**

[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

PM_{10} emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in lower PM_{10} emissions than heavier residual oils. Distillate oils have lower ash and sulfur content than residual oil, therefore, producing less PM_{10} emissions.

Available PM_{10} control technologies for the boilers are:

- Post-Combustion Controls
  - Dry or Wet Electrostatic Precipitator (ESP)
  - Fabric Filters
  - Wet Scrubber
  - Cyclone
- Fuel Switching
- Renewable Portfolio Standards (RPS)

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

Diesel engine generators D-11, D-15, D-16, and D-17 currently burn ULSD, and a four-factor analysis is not required for PM_{10}. CT-1 operates on a very limited basis, and post-combustion PM_{10} controls are not feasible for combustion turbines. Fuel switching from diesel to ULSD is not expected to significantly reduce PM_{10} emissions. Due to the limited operations of CT-1, 2017 PM_{10} emissions were less than 0.1

tons. Any reduction in PM_{10} emissions from CT-1 is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-1.

5.1.1. Post-Combustion Controls

PM_{10} emissions from residual oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, dry ESP, cyclones, and fabric filters are not good technological matches for the Hill boilers.

A wet ESP operates very similarly to a dry ESP but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. The wet ESP utilizes water to collect and remove the particles and produces a waste-water product. Flue gas leaving the wet ESP will be saturated and may result in a visual steam plume. The estimated PM_{10} control efficiency is up to ninety percent for a wet ESP.[25] Wet ESP is a technically feasible option for control of PM_{10} for the Hill boilers.

In wet scrubbers PM_{10} is removed from flue gas when the gas stream is brought into contact with a scrubbing liquid using several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. The PM_{10} in the gas stream is captured in the scrubbing liquid. The PM_{10}-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for the Hill boilers is considered a technically feasible option. The estimated PM_{10} removal efficiency for a wet scrubber is fifty to sixty percent.[26]

5.1.2. Fuel Switching

Residual oil has inherent ash that contributes to the emissions of filterable PM_{10}. Distillate fuels have less ash and ultimately lower filterable PM_{10} emissions. Filterable PM_{10} emissions could be reduced by switching to distillate fuel. Section 1 discussed the option of fuel switching with respect to reducing SO_2 emissions. As discussed in Section 1, Hawaiʻi Electric Light has limited fuel options. Switching to a distillate fuel will result in the PM_{10} emissions reductions and is technically feasible.

5.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (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 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 Hawaii 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.

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[25] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1.

[26] Ibid.

5.2. FOUR-FACTOR ANALYSIS

As discussed above, wet ESPs, wet scrubbers, and switching to distillate fuel are the best feasible options to reduce PM_{10} emissions. 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 wet ESPs, wet scrubbers, and switching to distillate fuel are discussed in the following sections.

5.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of wet ESPs, wet scrubbers, and switching to distillate fuel have been estimated. The cost effectiveness calculation is based on the following reduction in PM_{10} emissions:

- Wet Scrubbers – fifty percent,
- Switching to distillate fuel – sixty-seven percent to eighty-two percent, and
- Wet ESP – ninety percent.

Table 5-2 presents a summary of the cost effectiveness of wet scrubbers, switching to distillate fuel, and wet ESPs. The cost effectiveness ranges are:

- Wet Scrubbers - $10,500 per ton - $11,800 per ton and the total cost equals 300 thousand dollars ($300,000) annually and 4.5 million dollars ($4,500,000) over fifteen (15) years,
- Switching to distillate fuel – $254,000 per ton to $354,000 per ton and the total cost equals 11.7 million dollars ($11,700,000) annually and 175.5 million dollars ($175,500,000) over fifteen (15) years, and
- Wet ESPs - $82,600 per ton - $112,600 per ton and the total cost equals 5.1 million dollars ($1,500,000) annually and 76.5 million dollars ($76,500,000) over fifteen (15) years.

5.2.2. Time Necessary to Achieve Compliance

If the DOH determines that wet scrubbers or wet ESPs are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years. If the DOH determines that switching a distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

5.2.3. Energy and Non-Air Quality Environmental Impacts

ESPs, by design, apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a wastewater treatment plant. Further, the wastewater treatment process will generate a filter cake that would likely require landfilling.

Table 5-2. PM_{10} Cost Effectiveness of Wet ESP, Wet Scrubber and Switching to Distillate Fuel

Unit	Control Option	2017 PM_{10} Emissions (tpy)	Level of Control [A] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [B] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	146,017	11,823
	Distillate Fuel	24.7	71	7.2	17.5	4,439,388	253,908
	Wet ESP	24.7	90	2.5	22.2	1,836,790	82,627
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	170,875	10,548
	Distillate Fuel	32.4	63	11.8	20.6	7,285,011	354,347
	Wet ESP	32.4	90	3.2	29.2	3,283,308	112,596

[A] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emissions level for switching to a distillate fuel is based on the ratio of PM_{10} emissions from distillate combustion from AP-42, Tables 1.3-2 and 1.3-6 and the baseline emission factor.

[B] See Appendix A for total annual cost calculations for wet scrubber and wet ESP. The annual cost of switching to a distillate fuel is based on the incremental fuel cost from Table 3-3.

5.2.4. Remaining Useful Life

The remaining useful lives of the Hill 5 and Hill 6 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, for this four-factor analysis. However, Hawaiian Electric intends to retire the Hill 5 and Hill 6 boilers after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawaiʻi's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements 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 PM_{10}.

5.3. PARTICULATE MATTER CONCLUSION

The cost effectiveness of all the PM_{10} controls evaluated for the Hill boilers is more than $10,500 per ton, and for most controls and boilers is more than $82,600 per ton. The total cost of PM_{10} controls ranges from 300 thousand dollars ($300,000) annually and 4.5 million dollars ($4,500,000) over fifteen (15) years to 11.7 million dollars ($11,700,000) annually and 175.5 million dollars ($175,500,000) over fifteen (15) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, the EPA concluded that PM_{10} controls were not cost effective.[28]

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, Hawaiian Electric does not propose any PM_{10} emissions reductions in addition to its RPS program to meet the RHR requirements.

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[28] 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.

APPENDIX A: DETAILED COSTING

Appendix Table A-1. LNB with OFA Capital and O&M Cost Estimate

Parameters/Costs	Equation	Hill 5	Hill 6
Boiler design capacity, mmBtu/hr (C)		197	249
Boiler Type		Wall	Tangential
2017 Annual Heat Input, MMBtu/yr (H)		878,441	1,441,517
Unit Size, kW (kW)		14,100	23,000
Unit Size, MW (MW)		14.1	23.0
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
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	$1,377,076	$1,413,310
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	$9,541	$5,872
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	$20,656	$21,200
2. Capital recovery	= Equipment CRF x TCI	$151,196	$155,174
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$181,393**	**$182,245**

Source: All costs were estimated using Section 4.3 and Appendix D of the WARP 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). Chemical Engineering Journal.

[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 Hawaii'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 Hawaii'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 Hawaii's remote location.

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

		Hill 5	Hill 6
MW		14.1	23.0
Baseline NOx Emission Rate (lb/MMBtu)		0.57	0.49
2017 Annual Heat Input, MMBtu/yr		878,441	1,441,517
Max Heat Input (MMBtu/hr)		197	249
Capital Recovery Factor (CRF)		0.11	0.11
Cost Index [A]			
2018	603.1		
1999	390.6		
B =	(lb/MMBtu)	0.57	0.49
C =	(%)	90	90
A =	(kW)	14,100	23,000
Z (Eq. 1) =		0.91	0.91
Capital Cost (Eq. 2)	($/kW)	$212	$178
Capital Cost (2018)	($)	$4,612,942	$6,323,156
Hawaiʻi Island Construction Cost Multiplier [B]		1.840	1.840
Hawaiʻi Island Capital Cost (2018)		$8,487,814	$11,634,607
Annualized Capital Cost	($/yr)	$931,916	$1,277,417
G =		0.51	0.66
H =	(MMBtu/hr)	197	249
D =	($/kW)	$327	$275
Fixed O&M[C] (Eq. 3)	($/yr)	$30,445	$41,733
Variable O&M Cost (Eq. 4)	($/yr)	$83,927	$144,712
Total Annual Cost	**($/yr)**	**$1,046,288**	**$1,463,862**

$$\boxed{Z = \left[(B/1.5)^{0.05}(C/100)^{0.4}\right]}$$

Equation 1

$$\boxed{D = 75\left\{300{,}000\,\frac{Z}{A}\right\}^{0.35}}$$

Equation 2

Where:

D = Capital cost ($/kW)
B = NO_X (lb/10^6 Btu) at the inlet of the SCR reactor
C = NO_X removal efficiency (%)
A = Plant capacity (kW)

$$\boxed{E = D \times A \times C}$$

Equation 3

Where:

E = Fixed O&M cost ($/yr)
D = Capital cost ($/kW) from Equation 1
A = Plant capacity (kW)
C = A constant, 0.0066 yr-1

$$\boxed{F = G\{225 \times [0.37B \times H \times (C/100) \times (8760/2000)] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A\}}$$

Equation 4

Where:

F = Variable O&M Cost ($/yr)
G = Annual capacity factor (expressed as a fraction)
B = Inlet NO_X (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
H = Heat input (MMBtu/hr)
C = NO_X removal efficiency; range of 80-95%
D = Capital cost ($/kW)
A = Plant capacity (kW)

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)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers*, EPA/600/R-01/087, October 2001. A 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). Chemical Engineering Journal.

[B] The Hawaiʻi Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016 to account for factors unique to Maui s location plus an additional factor to account for additional Hawaiian Electric loadings and overhead.*

[B] Fixed Costs include elements such as labor, station power, capital additions/improvements

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	Equation/Reference	Hill 5	Hill 6
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s)[1]	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM)[1]	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	ACFM*((68+460)/(Tstack+460))	33,596	73,261
m_{wv} (lb/min)	SCFM * MC * 18/385	188	411
m_a (lb/min)	SCFM * (1-MC) * 29/385	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	*h (Estimated from psychrometric chart)*	23.00	23.00
Q_{SAT}	h * ma	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	1.15*(150*Q_{SAT}^0.56)	$57,290	$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	$57,290	$88,652
Auxiliary Costs (A2)	A2 = 0.1*A1	$5,729	$8,865
Equipment Costs (A)	A = A1 + A2	$63,019	$97,517
Instrumentation	0.10 A	$6,302	$9,752
Sales taxes	0.03 A	$1,891	$2,926
Freight	0.05 A	$3,151	$4,876
Purchased Equipment cost, PEC	**B = 1.18 A**	**$74,363**	**$115,070**
Direct Installation Costs			
Foundation & supports	0.06 B	$4,462	$6,904
Handling & erection	0.40 B	$29,745	$46,028
Electrical	0.01 B	$744	$1,151
Piping	0.05 B	$3,718	$5,754
Insulation for ductwork	0.03 B	$2,231	$3,452
Painting	0.01 B	$744	$1,151
Direct Installation Costs, DIC	**0.56 B**	**$41,643**	**$64,439**
Total Direct Costs, TDC	**PEC + DIC**	**$116,006**	**$179,510**
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	$7,436	$11,507
Construction & field expenses	0.10 B	$7,436	$11,507
Contractor fees	0.10 B	$7,436	$11,507
Start-up	0.01 B	$744	$1,151
Performance test	0.01 B	$744	$1,151
Model study	--		
Contingencies	0.03B	$2,231	$3,452
Total Indirect Costs, IC	**0.35 B**	**$26,027**	**$40,275**
Cost Index[5]			
a. 2018	603.1		
b. 2002	395.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Total Capital Investment (2018 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2018}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$303,144**	**$469,092**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $20/hr	$43,200	$43,200
Supervisor	15% of operator	$6,480	$6,480
Maintenance			
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual ($20.00/hr, 7.5 h/wk, 44 wk/yr)	$6,600	$6,600
Material	100% of maintenance labor	$6,600	$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$62,880**	**$62,880**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$6,063	$9,382
Property tax	1% of Total Capital Investment	$3,031	$4,691
Insurance	1% of Total Capital Investment	$3,031	$4,691
Overhead	60% of total labor and material costs	$37,728	$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$33,284	$51,504
Total Indirect Annual Costs		**$83,137**	**$107,995**
Total Annual Cost		**$146,017**	**$170,875**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Hill 5	Hill 6
Average High Exhaust Flow Rate (m^3/s)[1]		26.5	48.1
Average High Exhaust Flow Rate (ACFM)[1]		56,135	101,845
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)[4]	$ESCA = -\ln(p)/w_e \times 5.080 \times Q$	2,091	3,794
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	$25.5/acfm	$1,431,451	$2,597,038
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$644,153	$1,168,667
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$2,075,604	$3,765,705
Instrumentation	0.10 A	$207,560	$376,570
Sales taxes	0.03 A	$62,268	$112,971
Freight	0.05 A	$103,780	$188,285
Purchased Equipment cost, PEC	**B = 1.18 A**	**$2,449,212**	**$4,443,531**
Direct Installation Costs			
Foundation & supports	0.04 B	$97,968	$177,741
Handling & erection	0.50 B	$1,224,606	$2,221,766
Electrical	0.08 B	$195,937	$355,483
Piping	0.01 B	$24,492	$44,435
Insulation for ductwork	0.02B	$48,984	$88,871
Painting	0.02B	$48,984	$88,871
Direct Installation Costs, DIC	**0.67 B**	**$1,640,972**	**$2,977,166**
Total Direct Costs, TDC	**PEC + DIC**	**$4,090,185**	**$7,420,697**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$489,842	$888,706
Construction & field expenses	0.20B	$489,842	$888,706
Contractor fees	0.10B	$244,921	$444,353
Start-up	0.01B	$24,492	$44,435
Performance test	0.01B	$24,492	$44,435
Model study	0.02B	$48,984	$88,871
Contingencies	0.03B	$73,476	$133,306
Total Indirect Costs, IC	**0.57B**	**$1,396,051**	**$2,532,813**
Cost Index[5]			
a. 2018	603.1		
b. 1999	390.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Total Capital Investment (2018 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2018}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41).**	**$11,859,315**	**$21,515,993**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	2hr/shift*2shifts/day*365 days/yr * $20/hr	$29,200	$29,200
Supervisor	15% of operator	$4,380	$4,380
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 = $4125	$4,125	$4,125
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$37,705**	**$37,705**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$237,186	$430,320
Property tax	1% of Total Capital Investment	$118,593	$215,160
Insurance	1% of Total Capital Investment	$118,593	$215,160
Overhead	60% of total labor and material costs	$22,623	$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$1,302,089	$2,362,340
Total Indirect Annual Costs		**$1,799,085**	**$3,245,603**
TOTAL ANNUAL COST		**$1,836,790**	**$3,283,308**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] Electricity cost form U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

[3] Water cost from Maui County (https://www.mauicounty.gov/216/Water-Charges) lowest general rate.

[4] For ESP Plate Area (Section 3.2.1):

p = 1 - (Control Efficiency %)

5.080 ft^2/kacfm = 1 (s/m)

w_e = effective migration velocity (m/s), assume w_e = 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% effic

Q = system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

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

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March 31, 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 matter ("PM") control options for Hawaiian Electric sources relative to the two Class I 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 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 Oahu 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 Hawaiʻi 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 the EPA (consistent with their first decadal review approach) to set aside NOx and PM from the list of

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[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.

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.

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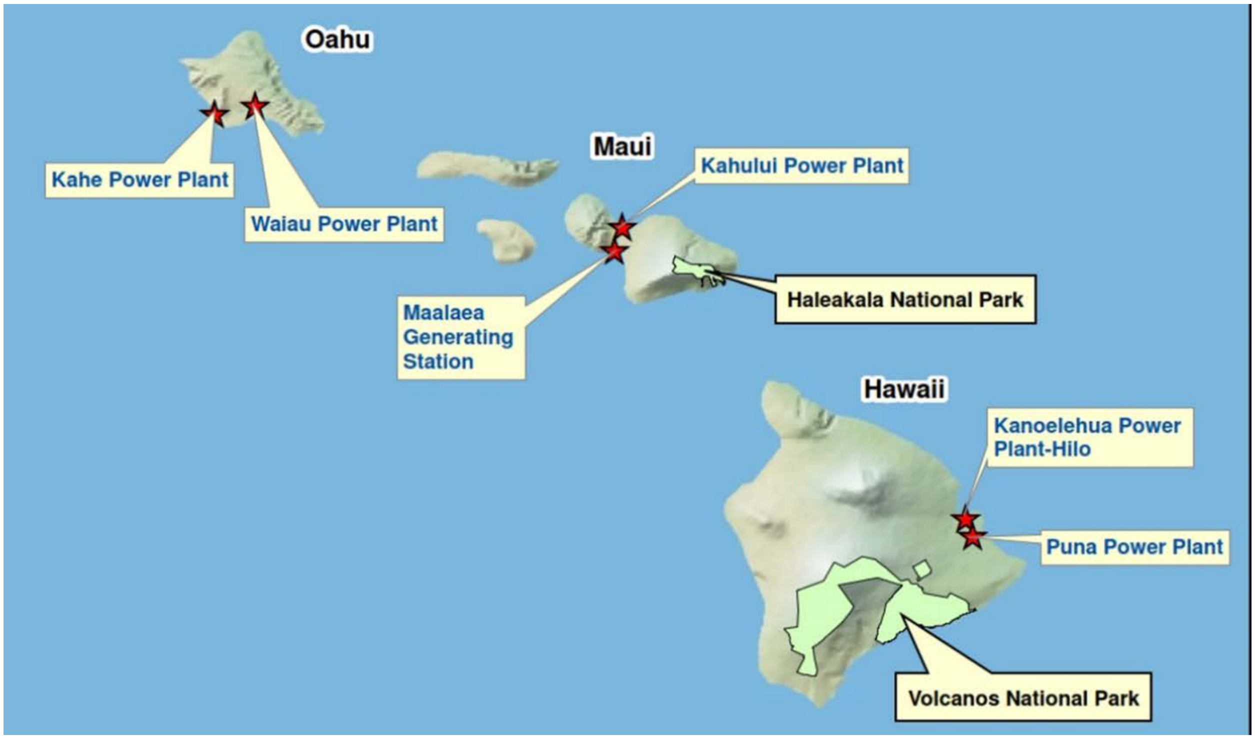
[2] Information on the volcanic SO_2 emissions in 2014 was provided by the EPA in their SO_2 National Ambient Air Quality Technical Support Document at EPA's 2016 SO_2 NAAQS TSD, at https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.

[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."* . . .

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[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.

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 (see Figure B-8), 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.

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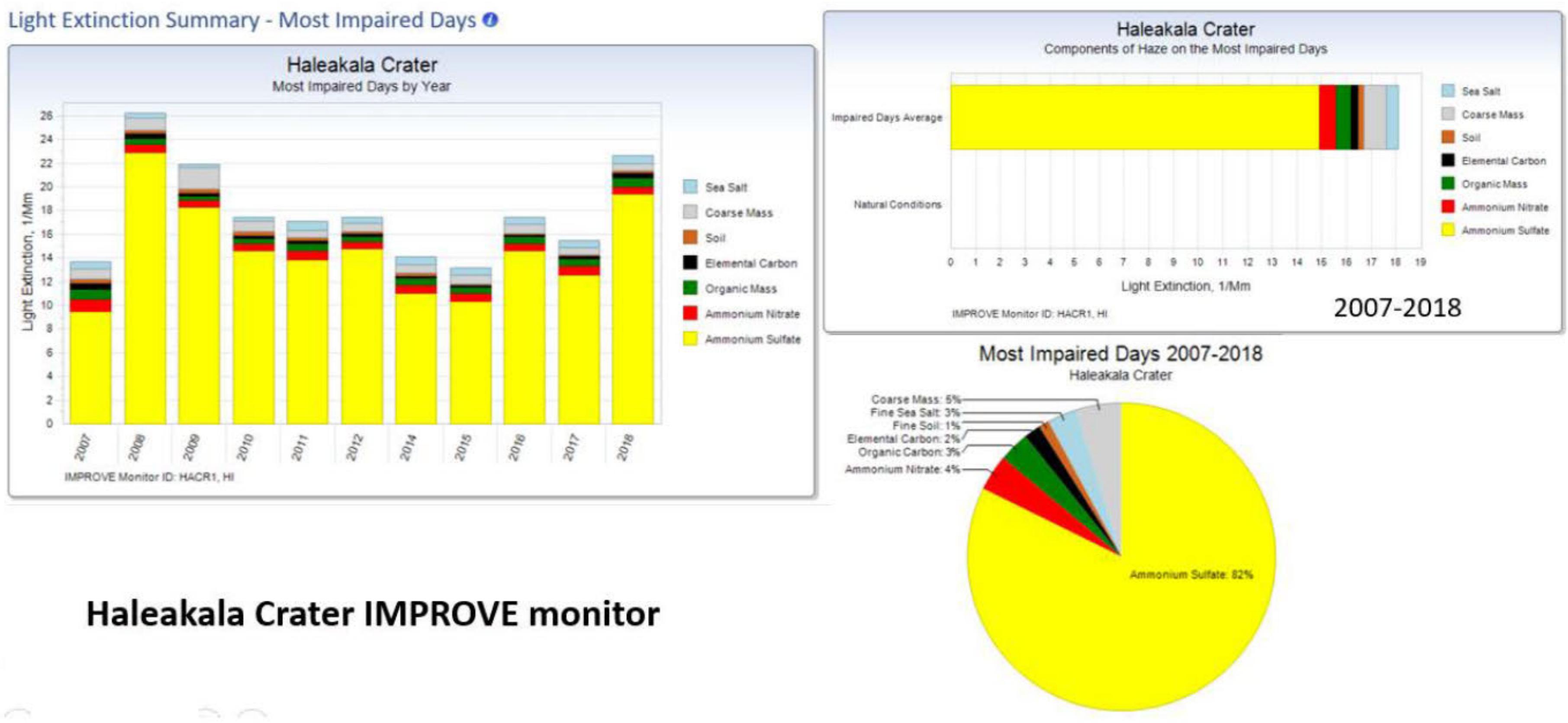
[7] Documentation for the CALPUFF modeling system is available from links provided at https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff.

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

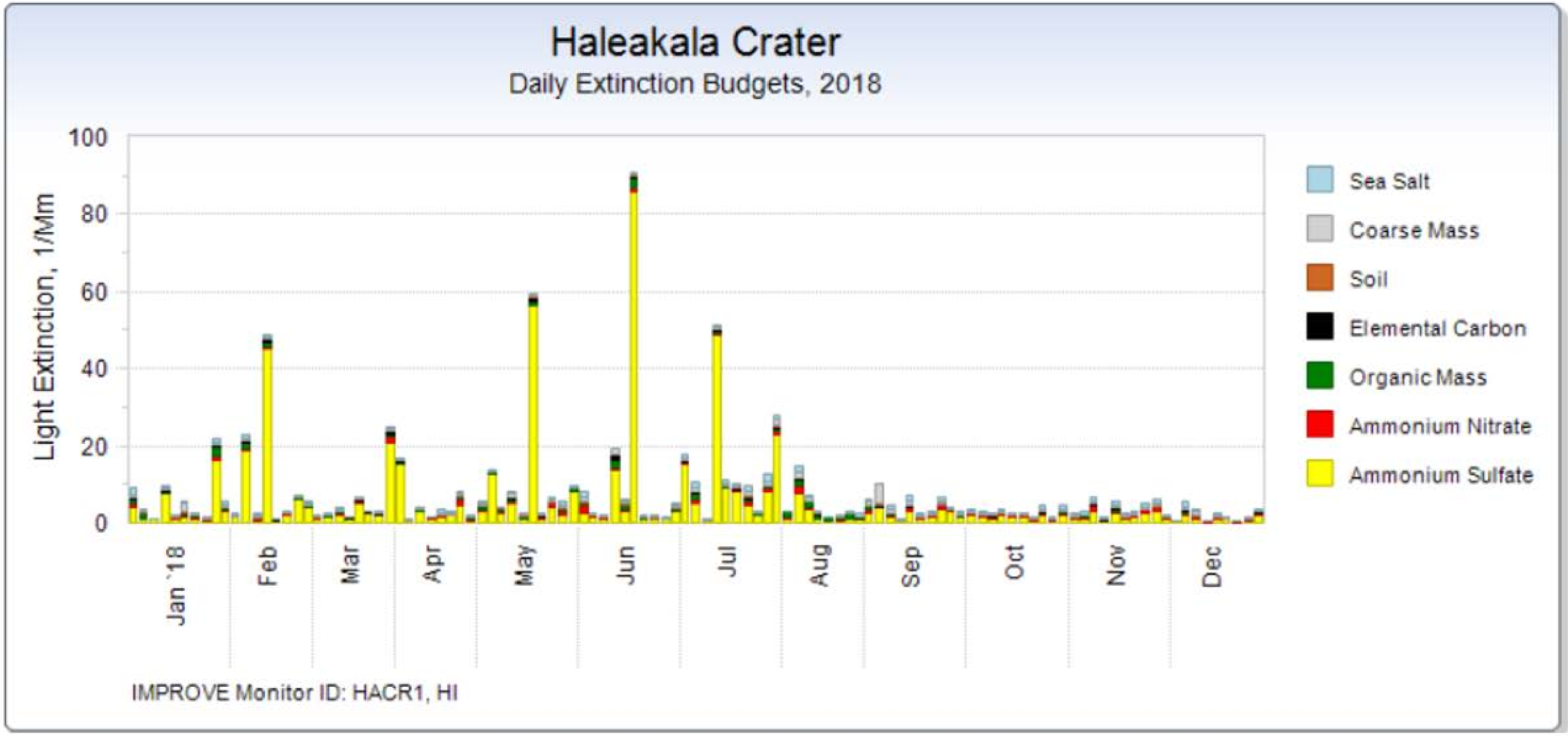
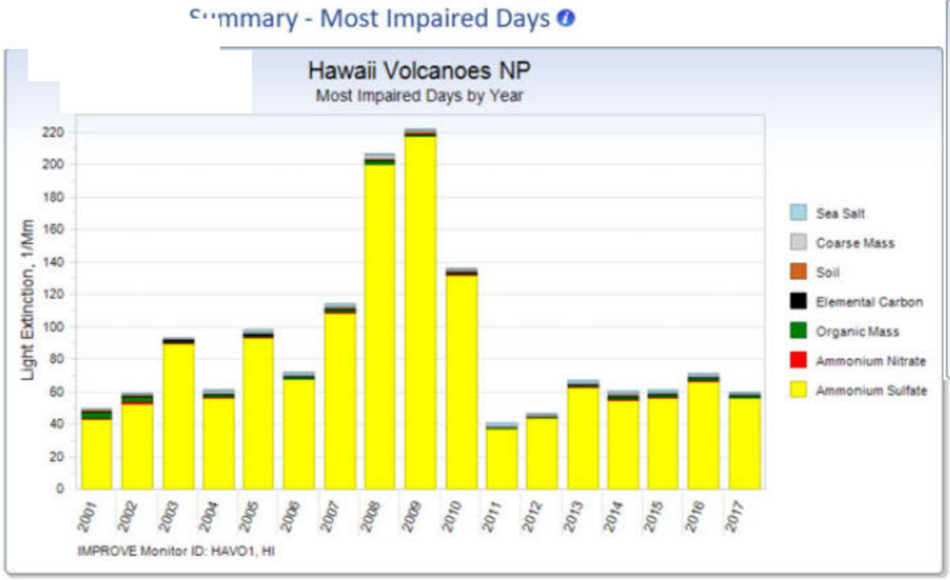
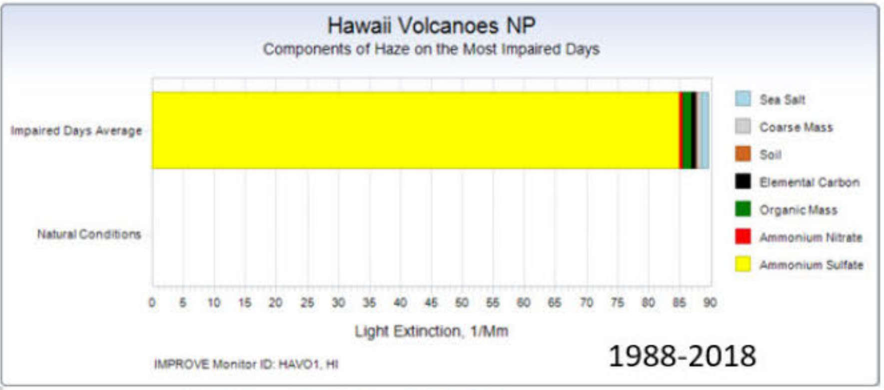
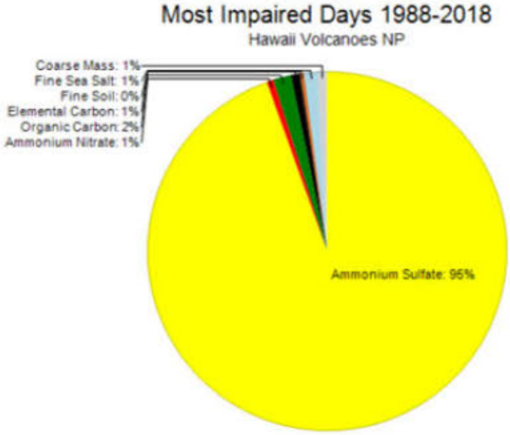


Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site



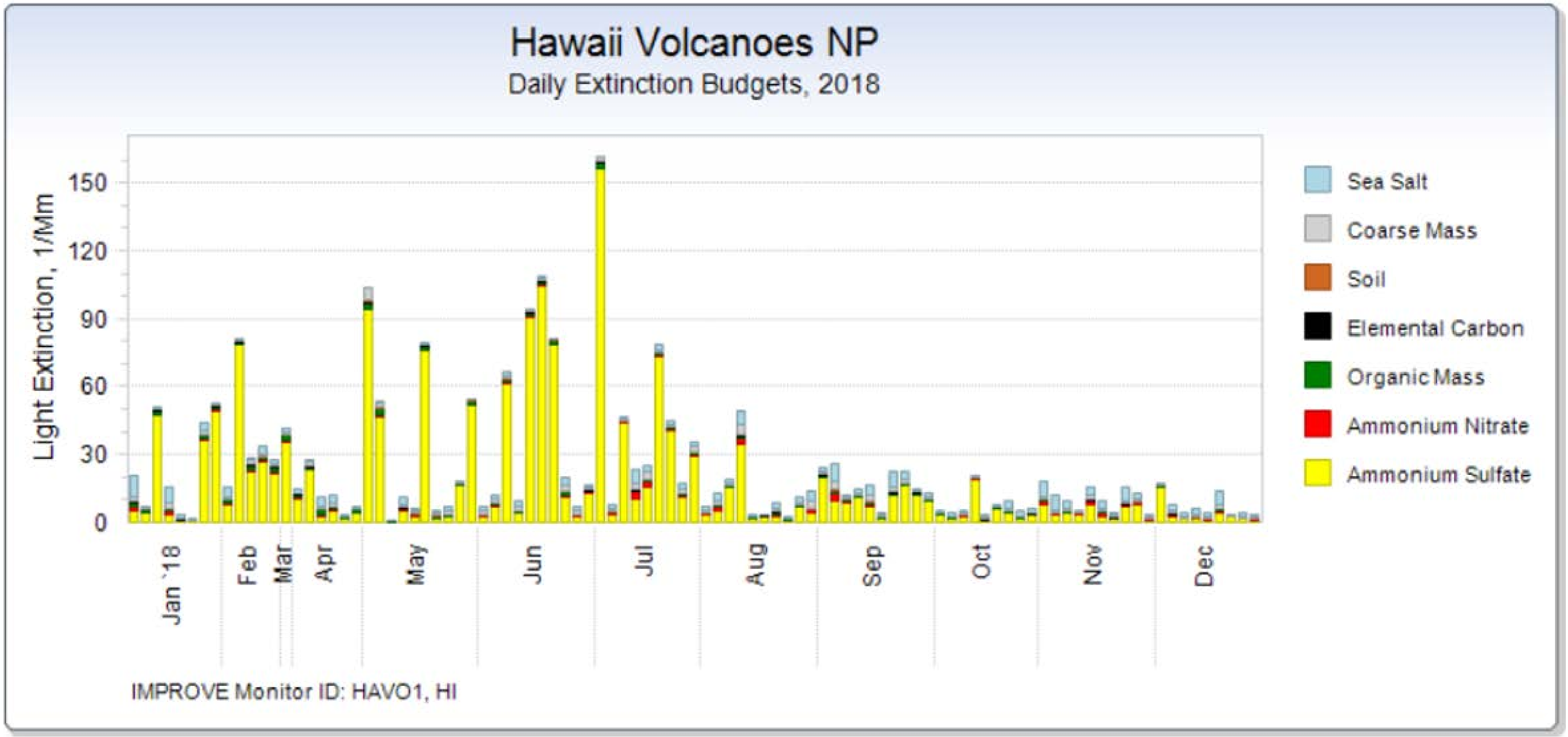


1988-2018



Hawaii Volcanoes NP IMPROVE monitor

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.

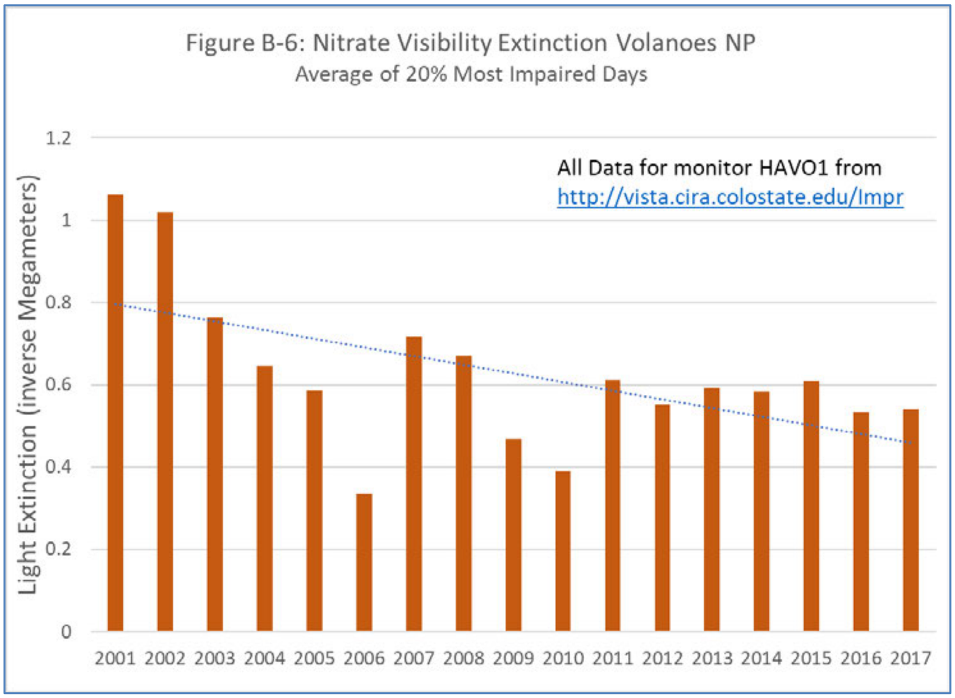


Figure B-6: Nitrate Visibility Extinction Volanoes NP

Average of 20% Most Impaired Days

All Data for monitor HAVO1 from http://vista.cira.colostate.edu/Impr

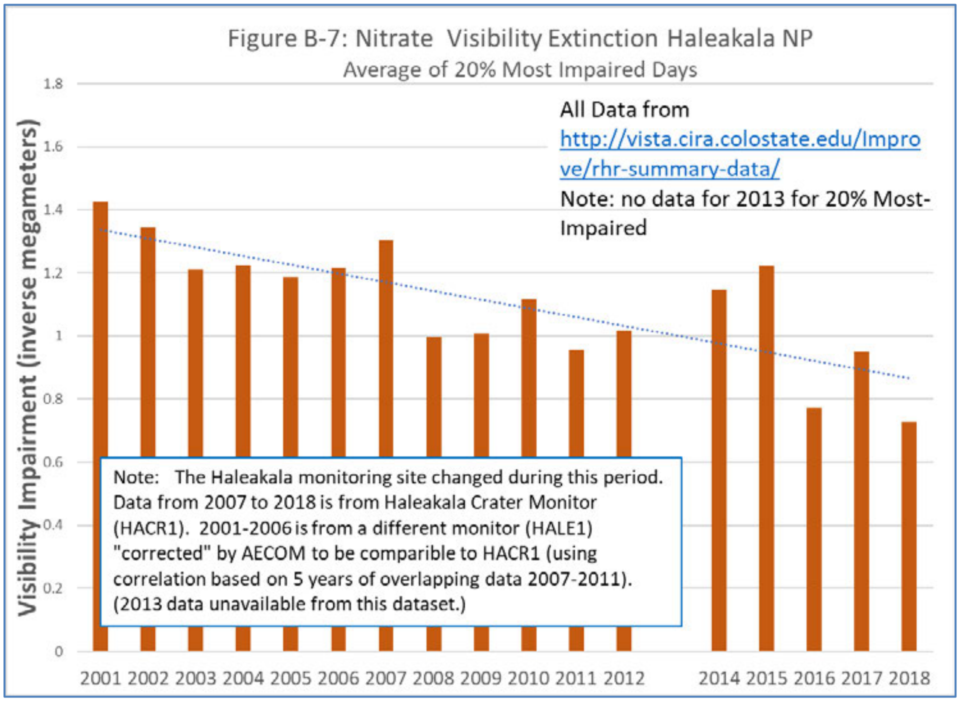


Figure B-7: Nitrate Visibility Extinction Haleakala NP

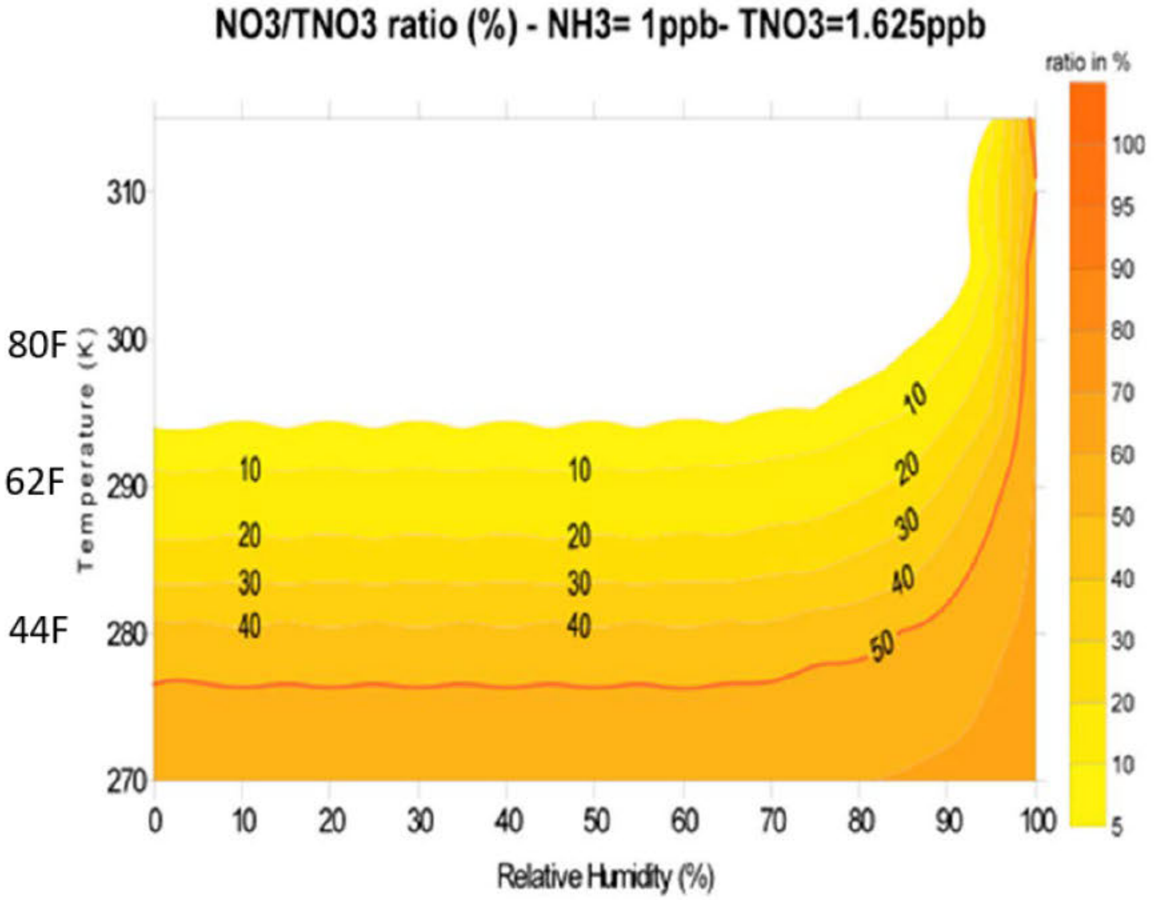
Average of 20% Most Impaired Days

All Data from http://vista.cira.colostate.edu/Improve/rhr-summary-data/

Note: no data for 2013 for 20% Most-Impaired

Note: The Haleakala monitoring site changed during this period. Data from 2007 to 2018 is from Haleakala Crater Monitor (HACR1). 2001-2006 is from a different monitor (HALE1) "corrected" by AECOM to be comparible to HACR1 (using correlation based on 5 years of overlapping data 2007-2011). (2013 data unavailable from this dataset.)

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.

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 is the largest source of NOx in the state. Volcanoes are commonly thought of as large sources of SO_2, but they also 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), while annual worldwide volcano SO_2 emissions are estimated[9] at approximately 23 Tg. This suggests that the level of NOx emissions is approximately equal to 6% of the total SO_2 emissions from volcanos. Hawaiʻi volcanic activity is estimated to have annual SO_2 emissions of approximately 2 million TPY of SO_2. This suggests that the volcanic emissions of NOx in Hawaiʻi are about 125,000 TPY. This level of natural NOx emissions is approximately 3 times greater than all anthropogenic NOx emissions in the entire state of Hawaiʻi (vehicle exhaust, industrial emissions, and other combustion sources) based upon the EPA's state emissions trends data[10] for 2017. Also, these estimated volcanic NOx emissions are approximately 10 times greater than the cumulative total 2017 NOx emissions emitted by all six Hawaiian Electric plants being reviewed for the Second Decadal Review.

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. Additionally, the biggest NOx source is the Kilauea volcano (approximately 125,000 TPY versus statewide[3] approximately 21,000 TPY from transportation and approximately 21,000 TPY from fuel combustion, of which only a small fraction are from Hawaiian Electric facilities). 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 conderation 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.

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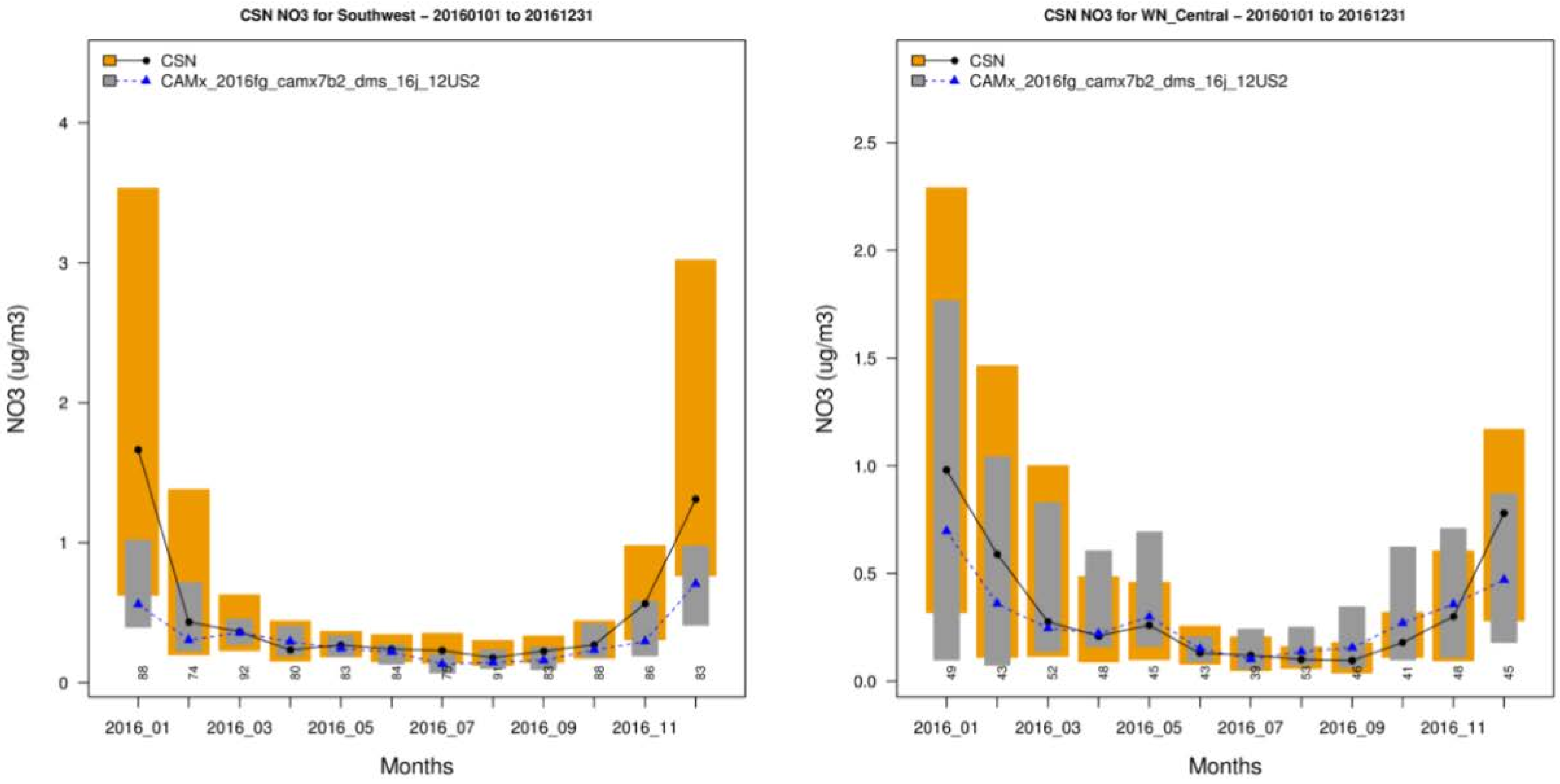
[8] Mather, T., 2004. A Volcanic Breath of Life? Chemistry World, 30 November 2004 Featured Article. https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article.

[9] Carn, S., V. Fioletov, C. McLinden, C. Li, and N. Krotkov, 2017. A decade of global volcanic SO_2 measured from space. *Sci. Rep*.7, 44095; doi: 10.1038/srep44095. https://www.nature.com/articles/srep44095.pdf.

[10] https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data.

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[11], 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 Oahu 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 Oahu. The wind rose plots show that the wind is almost always from the northeast and rarely blows from the Hawaiian Electric facilities on Oahu or Maui toward either of Hawaiʻi's Class I 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 Oahu 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 Figure B-10 and previous CALPUFF modeling both indicate that Hawaiian Electric generating stations on Oahu and Maui would have minimal impact to Class I area haze. Because of this, and the minimal impact of NOx due to nitrate chemistry, consideration of potential

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[11] 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.

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.

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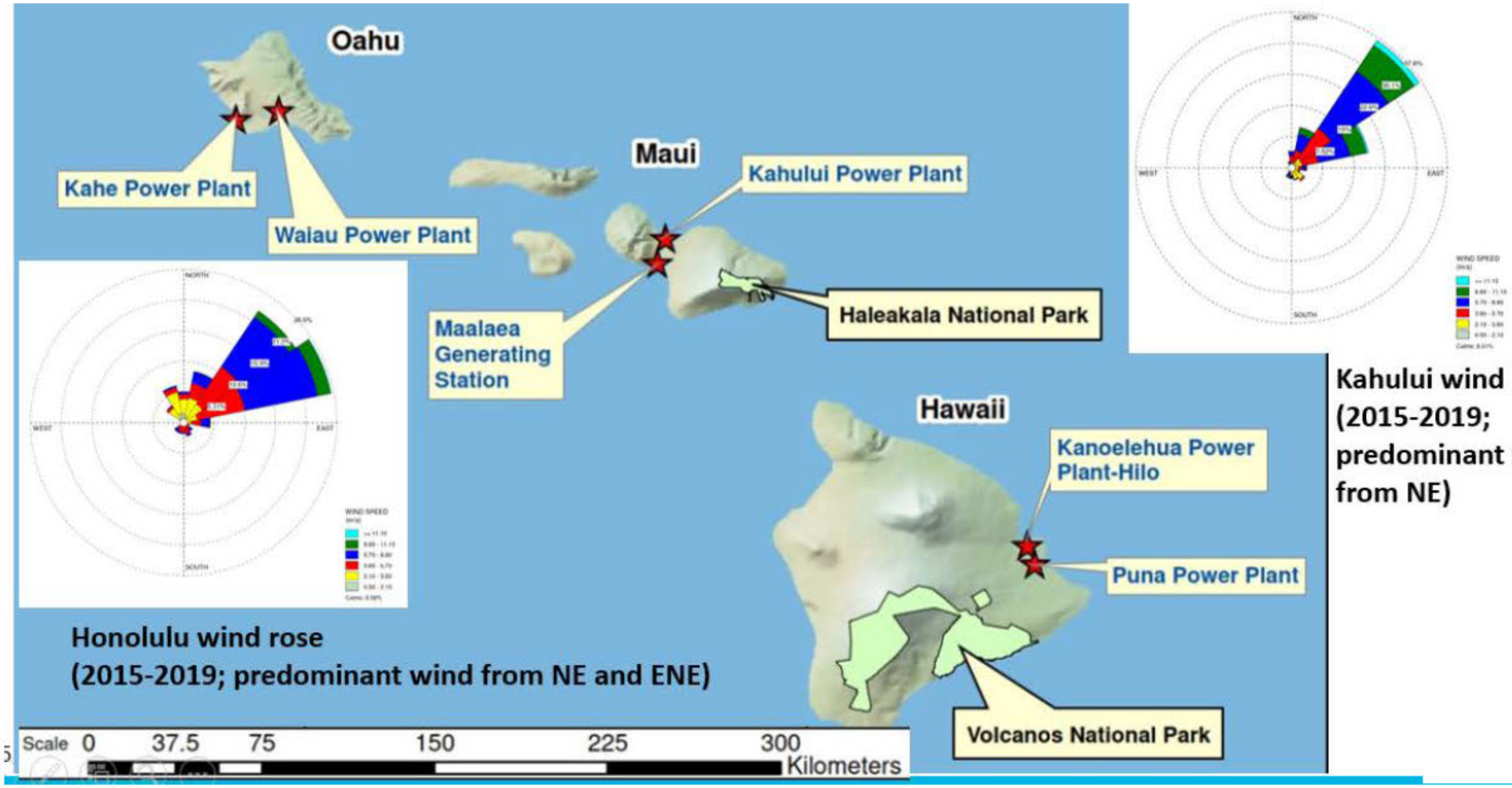
[12] https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.

[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.

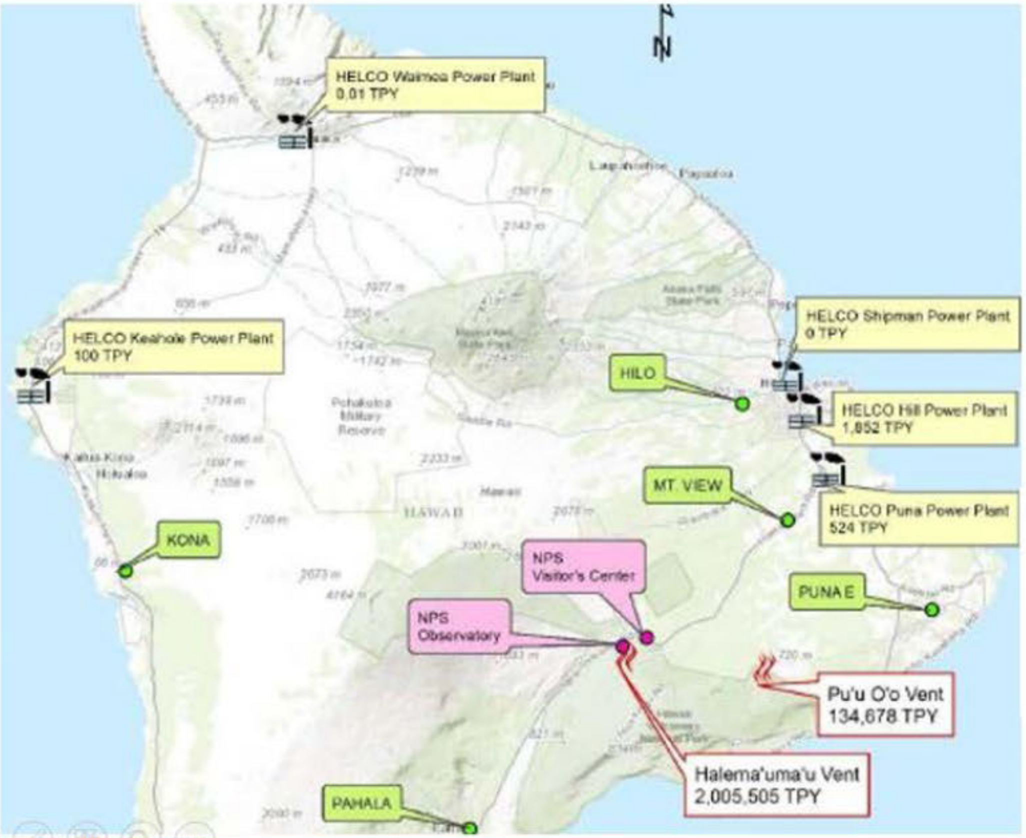
Figure B-10: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses



Honolulu wind rose
(2015-2019; predominant wind from NE and ENE)

Kahului wind rose
(2015-2019;
predominant wind
from NE)

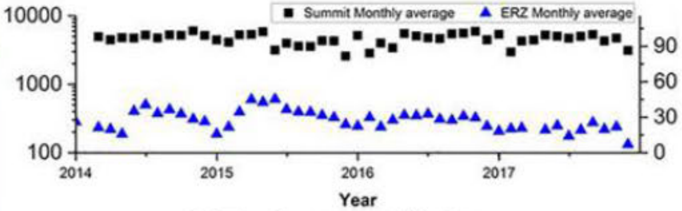
Figure B-11: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses



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 Hawaiʻi Island; all other sources in the state are not contributing to haze at the Class I areas.

- Implementation of Hawaiʻi'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 Hawaiʻi well before the year 2064. This Hawaiʻi 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 Hawaiʻi.

APPENDIX C: HAWAI‘I’S RENEWABLE PORTFOLIO STANDARDS CONTRIBUTION TO REGIONAL HAZE PROGRESS

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].

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[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 Hawai'i, 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 Hawai'i EGUs have made significant progress to date and have been ahead of the RPS interim targets.

Hawaiian Electric represents majority of Hawai'i'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.

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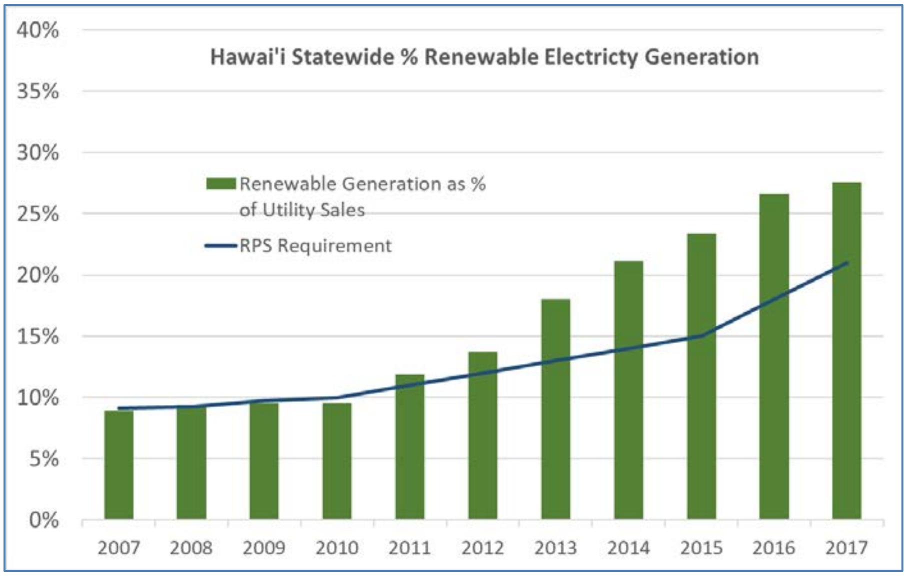
[2] "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i 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.

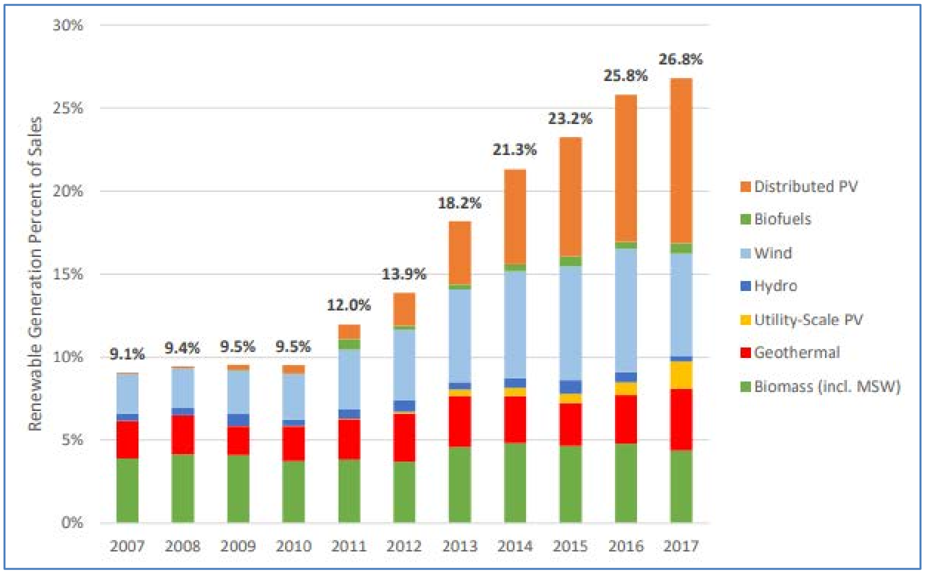
[3] *Hawai'i Public Utility Commission* (PUC), *"Report to the 2019 Legislature on Hawai'i's Renewable Portfolio Standards", Dec. 2018* https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

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]



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[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]

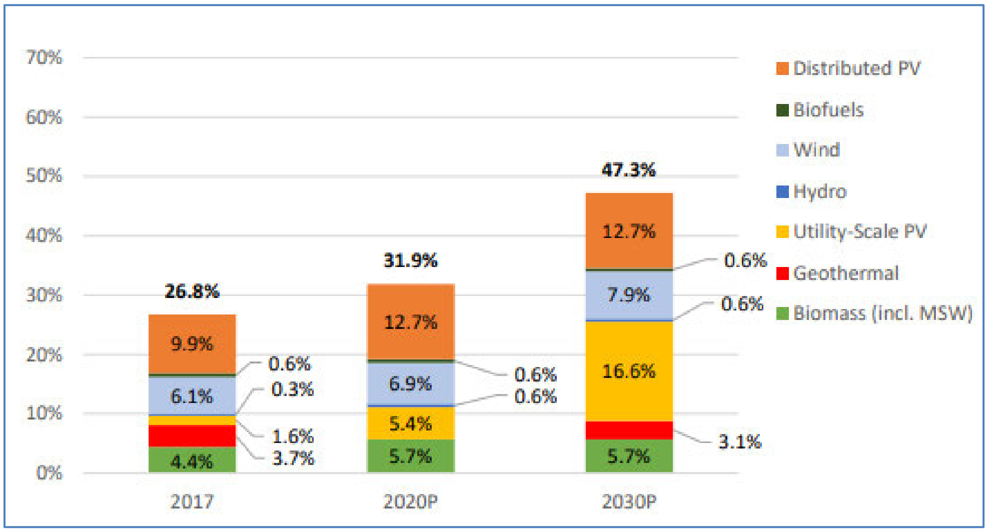

Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC's 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric's renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian 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.

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[5] PUC Dec. 2018 Report, page 2.

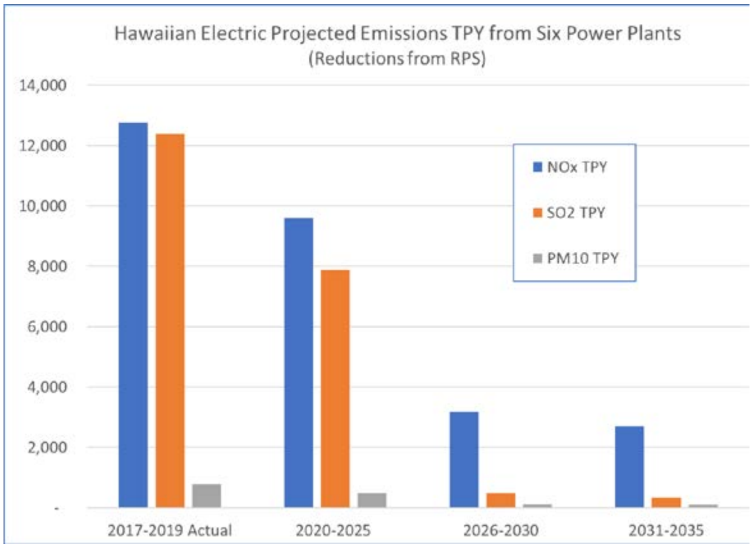
[6] PUC Dec. 2018 Report, Figure 2, page 16.

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.

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[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:

20-324E CAB
File No. 0234

July 10, 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. 0234-01-C
Hawaii Electric Light Company, Inc. (HELCO)
Kanoelehua-Hill Generating Station
Located At: 54 Halekauila Street, Hilo, Hawaii
UTM Coordinates: 284,300 Meters East and 2,179,800 Meters North, Zone 5

The Department of Health, Clean Air Branch (CAB) acknowledges receipt of the subject four-factor analysis on March 31, 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. Scott Takamoto of my staff at [redacted]

Sincerely,

Marianne Rossio

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

ST:rkb

Attachments

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 Hill 5 and Hill 6, Combustion Turbine CT-1, and Diesel Engine Generators D-11, D-15, D-16, and D-17:

a. The cost per ton of sulfur dioxide (SO_2) removed was provided for switching boiler fuel from high sulfur residual fuel oil No. 6 (maximum sulfur content of 2%) to a residual/distillate fuel blend with 1% sulfur content and from high sulfur residual fuel oil No. 6 to distillate fuel oil with 0.4% sulfur content. However, there was no cost analysis provided for a fuel switch from high sulfur residual fuel oil No. 6 to ultralow sulfur diesel (ULSD). Please provide the following for switching boiler fuel from high sulfur residual fuel oil No. 6 to ULSD:

   i) The cost per ton of SO_2, nitrogen oxide (NO_X), and particulate matter less than ten (10) microns in diameter (PM_{10}) reduced; and
   ii) The cost per total combined tons of SO_2, NO_x, and PM_{10} reduced.

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 Kanoelehua-Hill 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. Sections 3.2.4, 4.2.4, and 5.2.4 state 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. These sections of the analysis also indicate that Hawaiian Electric intends to retire Boilers Hill 5 and Hill 6, after replacement with renewable sources are carried out with the Renewable Portfolio Standards (RPS) no later than 2045. Please note that the RPS 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 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 Hawaiian Electric 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 selective catalytic reduction (SCR) at power plants of thirty (30) years and twenty (20) years for other sources.

e. The current prime interest rate (currently at 3.25%) should be used to estimate costs of additional emission controls, rather than seven percent (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 percent (3%) interest rate may also be considered.

f. Flue gas recirculation (FGR) is listed as a technically feasible control option; however, the cost effectiveness of this FGR was not evaluated. Please evaluate the cost effectiveness of FGR for the boilers.

g. Please add the combination of FGR plus low NO_X burner (LNB) and overfire air (OFA) to Table 4.2 and evaluate the cost effectiveness of the control option for the boilers.

h. Please add the combination of selective catalytic reduction (SCR) plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of the control option for the boilers.

i. A controlled emission level for NO_X of 0.1 pound per million British thermal unit (lb/MMBtu) is assumed for SCR in Table 4-3. 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.

j. Fuel costs are provided in 2019 dollars and the costs for add-on controls are in 2018 dollars. Please provide add-on control costs in 2019 dollars.

k. In Table A-2 of Appendix A, a “Hawaii Island Construction Cost Multiplier” of 1.840 for SCR is used based on cost of construction geographical multipliers from the “RSMeans Mechanical Cost Data 2016” to account for factors unique to Hawaii Island’s location plus an additional factor to account for additional Hawaiian Electric loadings and overhead. Retrofit factors pertain to the difficulty of installing a piece of hardware, regardless of location. While we recognize that it is appropriate to take into consideration the higher costs of transporting equipment and supplies, as well as higher labor rates, in unique areas like Hawaii or Alaska, those higher costs must be itemized, justified, and documented.

l. In Tables A-3 and A-4 of Appendix A, it is noted that a retrofit factor of 1.4 was used for retrofitting the boilers with a wet scrubber and wet electrostatic precipitator (ESP), respectively. The retrofit factor was based on average provided for ESP on page 3-41. Please provide page 3-41. Also, for selecting a retrofit factor of greater than one (1), please provide additional detail on the complexities involved with the specific boiler retrofit at the Kanoelehua-Hill Generating Station.

m. 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 eruptive activity ended in September 2018, those point sources now play a more significant part in SO_2 visibility impacts.

n. 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.

o. In the four-factor analysis, Hawaiian Electric states that no reduction measures in addition to Hawaii's 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, Hawaiian Electric 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 d above. In essence, Hawaiian Electric 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 analysis 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 to Comments on Four – Factor Analysis

Attachment 1
Responses to the DOH's July 10, 2020 Comments
Regional Haze Four-Factor Analysis, Dated March 31, 2020
Kanoelehua-Hill Generating Station
Hawaiʻi Electric Light Company, Inc.

a. The cost per ton of sulfur dioxide (SO_2) removed was provided for switching boiler fuel from high sulfur residual fuel oil No. 6 (maximum sulfur content of 2%) to a residual/distillate fuel blend with 1% sulfur content and from high sulfur residual fuel oil No. 6 to distillate fuel oil with 0.4% sulfur content. However, there was no cost analysis provided for a fuel switch from high sulfur residual fuel oil No. 6 to ultralow sulfur diesel (ULSD). Please provide the following for switching boiler fuel from high sulfur residual fuel oil No. 6 to ULSD:
   i) The cost per ton of SO_2, nitrogen oxide (NO_X), and particulate matter less than ten (10) microns in diameter (PM_{10}) reduced; and
   ii) The cost per total combined tons of SO_2, NO_X, and PM_{10} reduced.

   Response – The requested costs will be provided in 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 Kanoelehua-Hill 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 of 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 for 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

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

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 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. Sections 3.2.4, 4.2.4, and 5.2.4 state 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. These sections of the analysis also indicate that Hawaiian Electric intends to retire Boilers Hill 5 and Hill 6, after replacement with renewable sources are carried out with the Renewable Portfolio Standards (RPS) no later than 2045. Please note that the RPS 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 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 Hawaiian Electric 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 selective catalytic reduction (SCR) at power plants of thirty (30) years 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.

e. The current prime interest rate (currently at 3.25%) should be used to estimate costs of additional emission controls, rather than seven percent (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 percent (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]

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[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.

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

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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 - "

[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

f. Flue gas recirculation (FGR) is listed as a technically feasible control option; however, the cost effectiveness of this FGR was not evaluated. Please evaluate the cost effectiveness of FGR for the boilers.

   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-1 of the four-factor analysis was based on costing provided for LNB and LNB with overfire air. The cost of FGR and OFA are expected to be covered by this range and have a similar expected level of NO_X control. Therefore, the costing provided in Appendix Table A-1 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.

g. Please add the combination of FGR plus low NO_X burner (LNB) and overfire air (OFA) to Table 4.2 and evaluate the cost effectiveness of the control option for the boilers.

   Response – See the response to item f.

h. Please add the combination of selective catalytic reduction (SCR) plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of the control option for the boilers.

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

i. A controlled emission level for NO_X of 0.1 pound per million British thermal unit (lb/MMBtu) is assumed for SCR in Table 4-3. 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 go into the level of control that SCR can provide. Engineering studies are required to know the upper level of control that SCR can provide to the Hill boilers. For these reasons, the level of SCR control for Hill 5 and Hill 6 was set to 0.1lb/MMBtu. The requested updates will be provided in the updated four-factor analysis report.

j. Fuel costs are provided in 2019 dollars and the costs for add-on controls are in 2018 dollars. Please provide add-on 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.

k. In Table A-2 of Appendix A, a "Hawaii Island Construction Cost Multiplier" of 1.840 for SCR is used based on cost of construction geographical multipliers from the "RSMeans Mechanical Cost Data 2016" to account for factors unique to Hawaii Island's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead. Retrofit factors pertain to the difficulty of installing a piece of hardware, regardless of location. While we recognize that it is appropriate to take into consideration the higher costs of transporting equipment and supplies, as well as higher labor rates, in unique areas like Hawaii or Alaska, those higher costs must be itemized, justified, and documented.

Response – The use of a retrofit factor in lieu of itemized costing is a common method contained in the EPA CCM. The EPA 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 add-on controls and associated systems.

Although all of the factors listed above will impact the retrofit costs for the Kanoelehua-Hill 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 six (6) months to complete at a cost of approximately $237,500. 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.

l. In Tables A-3 and A-4 of Appendix A, it is noted that a retrofit factor of 1.4 was used for retrofitting the boilers with a wet scrubber and wet electrostatic precipitator (ESP), respectively. The retrofit factor was based on average provided for ESP on page 3-41. Please provide page 3-41. Also, for selecting a retrofit factor of greater than one (1), please provide additional detail on the complexities involved with the specific boiler retrofit at the Kanoelehua-Hill Generating Station.

Response – See response to item k.

m. 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 eruptive activity ended in September 2018, those point sources 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 is unchanged.

The four-factor analysis report acknowledged that Hawaiʻi Electric Light's Puna and Kanoelehua-Hill Generating Stations on Hawaiʻi Island are predominantly upwind of a Volcano's National Park. However, their combined annual SO_2 emissions of about 2,350 tons/year (2017) are still significantly lower than the 17,119 tons/year SO_2 emitted within the park itself (preliminary USGS 2019 estimate per DOH letter[7]). As such, the SO_2 emissions from volcanic emissions remain the predominate impact to visibility impairment, even with the reduced eruptive activity. Further because of the minimal impact, if any, any suggested controls are not cost effective.

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.

n. 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.

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[7] State of Hawaii Department of Health. Letter to Hawaiian Electric regarding Four-Factor Analysis for Regional Haze. July 10, 2020.

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 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 NO_X 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 m.

o. In the four-factor analysis, Hawaiian Electric states that no reduction measures in addition to Hawaii's 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, Hawaiian Electric 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 d above. In essence, Hawaiian Electric 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 analysis 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 analysis reports. In addition, the status of future renewable projects is listed on the *Renewable Project Status Board* on the Hawaiian Electric website. [8] The addition of renewable energy is an

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

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 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. 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.*
>
> ***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..."* [9]

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)[10,11] 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 Hawaiʻi 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)[12]. The Readiness Survey that was conducted by the Western Regional Air Partnership (WRAP) states:

> *Hawaiian Electric plans to use Hawaiʻi'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 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

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[9] 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

[10] 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

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

[12] 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

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

Kanoelehua-Hill Generating Station

Hawaiian
Electric

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1. EXECUTIVE SUMMARY

The State of Hawaiʻi has two Class I areas (National Parks) that trigger compliance with the Regional Haze Rule (RHR); Hawaiʻi's Mandatory Federal Class I Areas are Haleakalā National Park on Maui Island and Hawaiʻi Volcanoes National Park on the Hawaiʻi Island. This report documents the results of the Regional Haze Rule (RHR) second planning period four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric[1] for the two boilers (HILL 5 and HILL 6), one combustion turbine (CT-1), and four diesel engines (D-11, D-15, D-16, and D-17) at the Kanoelehua-Hill Generating Station (Kanoelehua-Hill). Hill 5 is a 14 megawatt (MW) wall-fired boiler, and Hill 6 is a 23 MW tangentially-fired boiler. Both boilers currently burn residual oil with a maximum sulfur content of 2.0 by weight (residual oil, residual high sulfur fuel oil). CT-1 is 11.6 MW simple cycle combustion turbine that currently burns diesel. D-11 is a 2 MW diesel engine generator, and D-15, D-16, and D-17 are 2.75 MW diesel engine generators. All of the diesel engine generators currently burn ultra-low sulfur diesel (ULSD). 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 the potential to show reasonable progress towards the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period Best Available Retrofit Technology (BART) five-factor analysis for Kanoelehua-Hill. Other long-term emission 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 State of Hawaiʻi Department of Health (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 emission reductions from add-on controls and changes in the method of operations.

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances that apply 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 years before the actual Regional Haze 2064 target date. These same issues were addressed by the U.S. Environmental Protection Agency (EPA) in the Federal Implementation Plan (FIP) and the State of Hawaiʻi Department of Health in their 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, 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.

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[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. BACKGROUND AND ADDITIONAL FACTORS

2.1. REGIONAL HAZE RULE BACKGROUND

In the 1977 amendments to the federal Clean Air Act (CAA), the U.S. 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 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 established an emissions cap of 3,550 tons of 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 ensure that reasonable progress is made during this first planning period toward the national goal of no anthropogenic visibility impairment by 2064 at Hawai‘i's two Class I areas.

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

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 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. 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.*

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 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 area. The WRAP Guidance itself states that 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 EPA's concern the WRAP subcommittee recommends a second step, application of

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[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, EPA-454/R-18-010, December 2018

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

the weighted emissions potential analysis (WEP).[7] On September 11, 2019, the DOH informed Hawai'i Electric Light that its Kanoelehua-Hill Generating Station was identified, based on the Q/d analysis, 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.

The SIP Guidance requires that the selection of controls necessary to make reasonable progress must consider the five required factors listed in section 51.308(f)(2)(iv), and other factors that are reasonable to consider. Hawaiian Electric and AECOM prepared summary, included in Section 2.2, which describes special circumstances that apply in Hawai'i that should be considered during the development of the Hawai'i 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 Hawai'i that should be considered during the development of the Hawai'i Regional Haze SIP. Significant among those circumstances is Hawai'i'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 its 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, Kanoelehua-Hill 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 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 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 Kanoelehua-Hill. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_X controls to be material.

2.2.2. 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. It should also be noted that

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[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)

volcanic activity on Hawaiʻi Island is the largest source of NO_X in the state. Volcanic activity on Hawaiʻi Island is by far the largest source of both SO_2 and NO_X in the state and 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. Any minimal impact of NOx, 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 RPS. Thus, the DOH should limit the haze precursors control evaluations solely to SO_2 for the Second Decadal Review for Kanoelehua-Hill.

2.2.3. Renewable Portfolio Standards

Based on AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO_2, NO_X, and PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill 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 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 Hawaii 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. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO_2 emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 2017 annual average fuel property data and fuel usage rates that were used in the control costing calculations and the baseline SO_2 emissions for the Kanoelehua-Hill units.

Table 3-1. 2017 Fuel Property Data and Fuel Usage Baseline SO_2 Emissions

		2017 Annual Average Fuel Properties [A]			2017 Annual Fuel Usage [B]		SO_2 Emissions	
Unit	Primary Fuel	Sulfur Content	HHV (Btu/gal)	Density (lb/gal)	Volume (gal/yr)	Heat Input (MMBtu/yr)	(lb/MMBtu) [C]	(TPY) [D]
Hill 5	Residual Oil	1.69%	150,985	8.33	5,818,061	878,441	1.87	820.6
Hill 6	Residual Oil	1.69%	150,985	8.33	9,547,405	1,441,517	1.87	1,346.6
D-11	ULSD	0.0004%	138,564	7.10	1,607	223	4.10E-04	<0.1
D-15	ULSD	0.0004%	138,564	7.10	8,450	1,171	4.10E-04	<0.1
D-16	ULSD	0.0004%	138,564	7.10	2,951	409	4.10E-04	<0.1
D-17	ULSD	0.0004%	138,564	7.10	4,733	656	4.10E-04	<0.1
CT-1	Diesel	0.0540%	136,533	6.96	5,053	690	5.51E-02	<0.1
							Total	**2,167.2**

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

[B] To account for ignition fuels and used oil usage the equivalent annual residual oil usage for Hill5 and Hill6 was calculated from the 2017 annual average fuel properties and reported SO_2 emissions.

[C] The SO_2 emission factors are based on 100% conversion of fuel sulfur to SO_2 and the calendar year 2017 annual average fuel density and higher heating value.

[D] 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 boilers are:

- Flue Gas Desulfurization (FGD)
    - Dry Sorbent Injection (DSI)
    - Spray Dryer Absorber (SDA)
    - Wet Scrubber
    - Circulating Dry Scrubber (CDS)
- Fuel Switching to a residual/distillate blended fuel or a distillate fuel
- Renewable Portfolio Standards (RPS)

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

Because, diesel engine generators D-11, D-15, D-16, and D-17 currently burn ULSD, and a four factor analysis is not required for SO_2.

CT-1 operates on a very limited basis and post-combustion SO_2 controls are not feasible for combustion turbines. Therefore, fuel switching to ULSD is the only feasible option to reduce SO_2 emissions.

3.1.1. Post-Combustion Controls

FGD applications have not been used historically for SO_2 control on oil-fired boilers the size the Kanoelehua-Hill Generating Station boiler Hiil 5 (14 MW) and Hill 6 (23 MW). As there are no known FGD applications for oil-fired boilers, the performance of FGDs on oil-fired boilers is unknown. CDS was identified by an internal engineering study in 2012 as the best FGD option for the Hawaiian Electric Kahe and Waiau boilers. However, the Hawaiian Electric Kahe and Waiau Boilers range in size from 49 MW to 142 MW in comparison to Hill 5 and Hill 6 which range in size from 14 MW to 23 MW. The SO_2 cost-effectiveness calculations for Kahe and Waiau showed that CDS was the least cost-effective option to reduce SO_2. The EPA took this into account when evaluating the Best Available Retrofit Technology (BART) presumptive SO_2 emission rate for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD[8]. Since there are no applications of FGD on oil-fired boilers in the U.S., FGD, including CDS, is considered an unproven technology for the control of SO_2 from the Hill boilers due to their size and lack of the technology being used in similar applications.

3.1.2. Fuel Switching

The Hill boilers currently burn residual high sulfur fuel oil with a maximum sulfur content of 2.0 percent by weight. The average sulfur content of the residual high sulfur fuel oil purchased in 2017 was approximately 1.69 percent by weight. Switching to a lower sulfur fuel would reduce SO_2 emissions in proportion to the reduction in fuel sulfur content.[9]

On Oahu, 0.5 percent by weight low sulfur fuel oil is produced and is used at Hawaiian Electric's Kahe and Waiau Generating Stations on Oahu, However, is not a technically feasible option for the Hill boilers. This low sulfur fuel oil has a higher viscosity and pour point than the residual high sulfur fuel oil used by the Hill boilers and the current fuel supply chain from Oahu to the Hill boilers cannot support this quality of fuel that is semi-solid at ambient temperatures. For the low sulfur fuel oil to be burned by the Hill boilers, the piping and tanks that are used to transport and store the oil would need to be heated, at a cost of 500 thousand dollars ($500,000) to 1 million dollars ($1,000,000), which is not economically feasible because of the very limited remaining time that oil will be burned by the Hill boilers. There are, however, technically feasible options which include blending the current residual high sulfur fuel oil with a lower sulfur distillate fuel (diesel with a maximum sulfur content of 0.4 percent by weight or ultra-low sulfur diesel (ULSD) with a maximum a maximum sulfur content of 0.0015 percent by weight) or switching to a lower sulfur distillate fuel. The SO_2 four-factor analysis evaluates these options.

CT-1 is currently permitted to burn diesel with a maximum sulfur content of 0.4 percent by weight. The average sulfur content of the diesel purchased in 2017 was approximately 0.054 percent by weight. Due to the limited operations of CT-1, 2017 emissions were less than 0.1 tons of SO_2, and any reduction in fuel sulfur content is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-1.

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 Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are

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[8] *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

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

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 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 Hawaii 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, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only technically feasible option to reduce SO_2 emissions for the Hill 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 switching the Hill boilers to a lower sulfur residual/distillate blended fuel, or a lower sulfur diesel are discussed in the following sections.

3.2.1. Cost of Compliance

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.

Kanoelehua-Hill currently purchases residual high sulfur fuel oil from Par Hawaii Refining, LLC (Par Hawaii); current fuel costs are provided in Appendix D. The fuels are refined on Oahu, and changes in quantities of residual high sulfur fuel oil and distillate fuels 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 its production capacity of ULSD. Therefore, increases in ULSD would require importing ULSD to Hawaiʻi and for parity, the price of diesel with a maximum sulfur content of 0.4 percent by weight is based on importing diesel to Hawaiʻi. Appendix D contains the estimated cost of importing ULSD and diesel to Hawaiʻi.

Table 3-2 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight based on blending the current residual high sulfur fuel oil with diesel with a maximum sulfur content of 0.4 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 high sulfur fuel oil/diesel blended fuel with a maximum sulfur content of 1.0 percent by weight is $6,559 per ton SO_2 and would increase fuel cost 6 million dollars ($6,000,000) annually and 180 million dollars ($180,000,0000) over thirty (30) years.

Table 3-3 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to diesel with a maximum sulfur content of 0.4 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 diesel with a maximum sulfur content of 0.4 percent by weight is $6,119 per ton SO_2 and would increase fuel cost 10 million dollars ($10,000,000) annually and 300 million dollars ($300,000,000) over thirty (30) years.

Table 3-4 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to residual high sulfur fuel oil/ULSD blend with a maximum sulfur content of 1.0 percent by weight based on blending the current residual high sulfur fuel oil with 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 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/ULSD blended fuel with a maximum sulfur content of 1.0 percent by weight is $5,682 per ton of SO_2 and would increase fuel cost 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years.

Table 3-5 presents a summary of the cost effectiveness of switching from residual high 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 to ULSD fuel with a maximum sulfur content of 0.0015 percent by weight is $5,026 per ton of SO_2 and would increase fuel cost 11 million dollars ($11,000,000) annually and 330 million dollars ($330,000,000) over thirty (30) years.

3.2.2. Time Necessary to Achieve Compliance

If the DOH determines that switching from residual high sulfur fuel oil to a residual high sulfur fuel oil /distillate blended fuel or a lower sulfur diesel is needed to achieve reasonable progress, it is anticipated that this change would take two to three years to implement because of several factors: 1) Although not entirely under its control, 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 used for replacement, the effect on the fuel supply, and ability of the local refinery to accommodate the change may be significantly impacted; and 6) Imported fuel may be required if there is a lack of local supply.

3.2.3. Energy and Non-Air Quality Environmental Impacts

There are no energy and non-air quality environmental impacts 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 Kanoelehua-Hill. This increase will impact the price of electricity for Hawaiian Electric customers because it will not only increase the cost of electricity produced by Kanoelehua-Hill, but it will also increase the cost of electricity that Hawaiian Electric purchases from independent power producers (IPPs). The contracts with the IPPs are tied to Hawaiian Electric's "avoided cost" of producing electricity. Thus, as Hawaiian Electric's fuel costs increase for Kanoelehua-Hill, the price that the IPPs receive for the electricity they provide increases. As a result, the costs of all electricity sources on Hawaiʻi Island increase as Hawaiian Electric's fuel costs increase.

The impact on the price of electricity 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 guidance10 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, given the fragile condition of the state's fuel supply and Hawaiian Electric's position as a major customer in the state's fuel market, a fuel supply change could have sweeping effects on the island's fuel market that may not be apparent from the cost estimates associated with Hawaiian Electric such as the ability of the local refinery to accommodate the change and potential need for imported fuel.

Table 3-2. SO_2 Cost Effectiveness of Switching to a Residual Oil/Diesel Blended Fuel

	Current Residual Oil [A]					Residual Oil/Distillate Blend (1.0% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	141,953	6,188,253	462.06	358.54	0.38	2,351,536	6,559
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	141,953	10,154,888	758.24	588.36	0.38	3,858,858	6,559

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

[B] Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted averge of the 2017 fuel HHV and density and contract fuel sulur limits (2.0% for residual oil and 0.4% for diesel).

[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 3-3. SO_2 Cost Effectiveness of Switching to Diesel Fuel

	Current Residual Oil [A]					Diesel (0.4% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	136,533	6,433,896	179.20	641.40	0.61	3,924,677	6,119
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	136,533	10,557,987	294.07	1,052.53	0.61	6,440,372	6,119

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

[B] Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).

[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 Switching to a Residual Oil/ULSD Blended Fuel

	Current Residual Oil [A]					Residual Oil/ULSD Blend (1.0% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	144,774	6,067,657	468.21	352.39	0.33	2,002,327	5,682
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	144,774	9,956,991	768.33	578.27	0.33	3,285,807	5,682

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

[B] Based on a blend of 50.0% residual oil and 50.0% ULSD fuel and the weighted averge of the 2017 fuel HHV and density 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 3-5. SO_2 Cost Effectiveness of Switching to ULSD

	Current Residual Oil					ULSD (0.0015% maximum Sulfur)						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	138,564	6,339,628	0.66	819.94	0.65	4,120,758	5,026
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	138,564	10,403,294	1.08	1,345.52	0.65	6,762,141	5,026

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

[B] Based on 2017 average HHV and density and contract fuel sulfur limit.

[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).

3.2.4. Remaining Useful Life

Hawaiian Electric's PSIP[11], which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that Hill 5 boiler will be retired in 2027, and Hill 6 boiler will be retired in 2030. Although the plan is not expressly binding, this is a necessary step to meet Hawaiʻi's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements will 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 to a residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight ranges from $5,700 to $6,600 per ton SO_2 and would increase the fuel cost over 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,0000) over thirty (30) years. The cost effectiveness of switching to a distillate fuel with a maximum sulfur content of 0.4 percent by weight is $6,100 per ton SO_2 and would increase fuel cost 10 million dollars ($10,000,000) annually and 300 million dollars ($300,000,000) over thirty (30) years. The cost effectiveness of switching to ULSD fuel with a maximum sulfur content of 0.0015 percent by weight is $5,000 per ton of SO_2 and would increase fuel cost 11 million dollars ($11,000,000) annually and 330 million dollars ($330,000,000) over thirty (30) years. With the exception of switching to ULSD, 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, it should be mentioned that other long- term emission reduction strategies, such as those included as part of the Hawaiʻi RPS, EEPS, and the GHG ERP may be viable alternatives that would create greater benefits and allow for the demonstration of reasonable progress.

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

[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

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawaiʻi's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_X emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 Kanoelehua-Hill.

Table 4-1. Baseline NO_X Emissions

	NO_X Emissions		
Unit	**Primary Fuel Emissions Factor (lb/MMBtu) [A]**	**Adjusted Emission Factor (lb/MMBtu) [B]**	**(TPY) [C]**
Hill 5	0.572	0.573	251.5
Hill 6	0.490	0.491	353.6
D-11	3.200	--	0.4
D-15	3.200	--	1.9
D-16	3.200	--	0.7
D-17	3.200	--	1.0
CT-1	0.880	--	0.3
		Total	**609.3**

[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).

D-11, D-15, D-16, D-17, and CT-1 operate on a very limited basis. Total 2017 NO_X emissions from these units were less than five (5) tons, and any reductions in NO_X emissions are expected to have a negligible impact on regional haze reasonable progress. Therefore, the four-factor analysis was not conducted for D-11, D-15, D-16, D-17, and CT-1.

4.1. NITROGEN OXIDES CONTROL OPTIONS

The characterization of emission controls available and potentially applicable to the source is a necessary step before the four-factors can be analyzed. NO_X emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e., fuel versus combustion air) has led to the use of the terms "thermal NO_X" and "fuel NO_X." 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. 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 the form of nitrogen dioxide (NO_2). The NO_2/NO_X in-stack ratio for boilers is typically less than ten percent.

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

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. 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
  - Flue Gas Recirculation (FGR)
  - Overfire Air (OFA)
  - Low NO_X Burners (LNB)
- Post-Combustion Controls
  - 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 Kanoelehua-Hill boilers currently burn residual oil. Blending the current residual oil with distillate fuel or switching to a distillate fuel will result in only 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)**	**Hill 5**	**Hill 6**
Residual Oil	0.313	0.213	--	--
Distillate (ULSD)	0.171	0.171	45%	20%
50/50 Blend	--	--	23%	10%

[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.

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 operated without additional controls, the NO_X control range for wall-fired boilers (Hill 5) with FGR is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[14] This control is a technically feasible option for the Hill boilers.

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

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. OFA as a single NO_X control technique results in estimated NO_X emissions for wall-fired boilers (Hill 5) is approximately 0.30-0.45 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.20-0.30 lb/MMBtu.[15] This control is a technically feasible option for the Hill boilers.

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 (Hill 5) is approximately 0.25-0.35 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[16] When combined with OFA, the estimated NO_X control range on wall-fired boilers (Hill 5) is approximately 0.25-0.30 lb/MMBtu, and for tangentially-fired boilers (Hill 6) is approximately 0.15-0.20 lb/MMBtu.[17] LNB systems are technically feasible for the Hill boilers.

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 estimated NO_X control range for SCR is approximately 0.05-0.10 lb/MMBtu for a wall-fired boiler (Hill 5), and for tangentially-fired boilers (Hill 6) is approximately 0.03-0.10 lb/MMBtu.[18] When SCR is coupled with combustion controls the estimated NO_X control level is 0.05 lb/MMBtu. This control is a technically feasible option for the Hill boilers.

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[15] Ibid.

[16] Ibid.

[17] Ibid.

[18] Ibid.

4.1.3.2. 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 (Hill 5) is approximately 0.30-0.40 lb/MMBtu and approximately 0.20-0.40 lb/MMBtu when coupled with combustion controls, and for tangentially-fired boilers (Hill 6) is approximately 0.20-0.25 lb/MMBtu and approximately 0.15-0.20 lb/MMBtu when coupled with combustion controls.[19] The estimated control range for a uncontrolled boiler is in the same range as combustion controls. 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 installing reagent injection ports, and the NO_X concentration.[20] 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. However, the cost effectiveness was evaluated.

4.1.4. Rank of Technically Feasible NO_X Control Options by Effectiveness

The next step is to rank the technically feasible options according to effectiveness. Table 4-3 provides a ranking of the control levels for the controls listed in the previous section.

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 - 0.20
SNCR	0.30 - 0.40	0.20 - 0.25
OFA	0.30 - 0.45	0.20 - 0.30
Fuel Switching	0.31 - 0.44	0.39 - 0.44

The control levels in Table 4-3 are presented as a range. This is due to the specific level of control that is achievable for the Hill boilers based on the application of the controls listed in Table 4-3 is unknown. Engineering studies would be required for each boiler in order 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 six (6) months to complete at a cost $237, 500 for the Hill boilers. It is anticipated that combustion controls such as LNB and possibly LNB in combination with OFA or FGR can achieve a NO_X emissions level of approximately 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively. As noted in Table 4-1, the Hill boilers are currently emitting in the range of 0.49 lb/MMBtu to 0.57 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 and SNCR can achieve a NO_X emissions level of approximately 0.30 lb/MMBtu for Hill 5 and 0.20 lb/MMBtu

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[19] Ibid.

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

for Hill 6. SNCR combined with combustion controls can achieve a NO_X emissions level of approximately 0.20 lb/MMBtu for Hill 5 and 0.15 lb/MMBtu for Hill 6.

4.1.5. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_X emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (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 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 Hawaii 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.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching, combustion controls, SNCR and SCR are the highest ranking feasible option to reduce NO_X emissions. 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 fuel switching, adding combustion controls, SNCR and SCR 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. The cost effectiveness of combustion controls is based on a controlled NO_X emissions level of 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively. At this time, it is unknown if LNBs 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 assumed that a NO_X emissions level of 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively, can be achieved with combustion controls. The cost of fuel switching is discussed in Section 3.2.1.

The cost effectiveness of SNCR is based on a controlled NO_X emissions level of 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively. The cost effectiveness of SNCR combined with combustion controls is based on a controlled NO_X emissions level of 0.20 lb/MMBtu and 0.15 lb/MMBtu for Hill 5 and Hill 6, respectively.

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 SCR costing is based on generic EPA control costing[21] which does not consider Hawai'i's remote location which results in additional shipping and higher construction cost. To account for these higher costs, a Hawai'i Island construction cost multiplier[22] of 1.840 was applied to the capital SCR cost.

Table 4-4 presents a summary of the cost effectiveness of fuel switching, adding combustion controls, SNCR, SNCR combined with combustions controls, SCR and SCR combined with combustions controls. The cost effectiveness is determined by dividing the annual cost by the annual reduction in NO_X emissions. The cost effectiveness of fuel switching exceeds $34,600 per ton and the total cost exceeds 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years. The cost effectiveness of combustion controls ranges from $700 per ton to $1,200 per ton of NO_X and the total cost equals 300 thousand dollars ($300,000) annually and 9 million dollars ($9,000,000) over thirty (30) years. The cost effectiveness of SCR ranges from $3,900 per ton to $4,000 per ton of NO_X and the total cost equals 1.9 million dollars ($1,900,000) annually and 57 million dollars ($57,000,000) over thirty (30) years. The cost effectiveness of SCR plus combustion control ranges from $4,000 per ton to $4,100 per ton of NO_X and the total cost equals 2.2 million dollars ($2,200,000) annually and 66 million dollars ($66,000,000) over thirty (30) years.

The cost effectiveness of SNCR ranges from $1,600 per ton to $2,300 per ton of NO_X and the total cost equals 600 thousand dollars ($600,000) annually and 18 million dollars ($18,000,000) over thirty (30) years. The cost effectiveness of SNCR plus combustion control ranges from $1,900 per ton to $2,600 per ton of NO_X and the total cost equals 900 thousand dollars ($900,000) annually and 27 million dollars ($27,000,000) over thirty (30) years.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in 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 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 NOX, 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.

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[21] Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance, Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS. Docket ID No. EPA-HQ-OAR-2015-0500, November 2015

[22] The Maui construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016* to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead.

Table 4-4. NO_X Cost Effectiveness 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)
Hill 5	Residual Oil/ULSD Blend [D]	251.5	0.44	878,441	193.7	57.8	2,002,327	34,615
	ULSD [D]	251.5	0.31	878,441	138.3	113.2	4,120,758	36,410
	Combustion Controls	251.5	0.30	878,441	131.8	119.7	142,201	1,188
	SNCR	251.5	0.30	878,441	131.8	119.7	277,987	2,322
	SNCR+Combustion Controls	251.5	0.20	878,441	87.8	163.7	420,188	2,568
	SCR	251.5	0.10	878,441	43.9	207.6	803,978	3,873
	SCR+Combustion Controls	251.5	0.05	878,441	22.0	229.5	946,179	4,122
Hill 6	Residual Oil/ULSD Blend [D]	353.6	0.44	1,441,517	318.2	35.4	3,285,807	92,924
	ULSD [D]	353.6	0.39	1,441,517	282.9	70.7	6,762,141	95,619
	Combustion Controls	353.6	0.20	1,441,517	144.2	209.4	141,993	678
	SNCR	353.6	0.20	1,441,517	144.2	209.4	325,124	1,552
	SNCR+Combustion Controls	353.6	0.15	1,441,517	108.1	245.5	467,117	1,903
	SCR	353.6	0.10	1,441,517	72.1	281.5	1,131,872	4,021
	SCR+Combustion Controls	353.6	0.05	1,441,517	36.0	317.6	1,273,865	4,011

[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 fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

[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 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

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

4.2.4. Remaining Useful Life

EPA's recommend capital cost recovery periods of thirty (30) years was used for the combustion controls and SCR costing and twenty (20) years was used for SNCR. However, Hawaiian Electric's PSIP[23], which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that Hill 5 boiler will be retired in 2027, and Hill 6 boiler will be retired in 2030. Although the retirement dates are not expressly binding, this is a necessary step to meet Hawaiʻi's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements will 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 fuel switching exceeds $34,600 per ton of NO_X and the total cost exceeds 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years. Fuel switching is less effective, and the costs are well above the other NO_X controls evaluated.

The cost effectiveness of adding combustion controls the Hill boilers ranges from $700 per ton to $1,200 per ton of NO_X and the total cost equals 300 thousand dollars ($300,000) annually and 9 million dollars ($9,000,000) over thirty (30) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, 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.[24]

The cost effectiveness of adding SNCR to the Hill boilers ranges from $1,900 per ton to $2,300 per ton of NO_X and the total cost equals 600 thousand dollars ($600,000) annually and 18 million dollars ($18,000,000) over thirty (30) years. The cost effectiveness of SNCR plus combustion control ranges from $1,900 per ton to $2,600 per ton of NO_X and the total cost equals 900 thousand dollars ($900,000) annually and 27 million dollars ($27,000,000) over thirty (30) years. 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 these results, SNCR does not offer a significantly better control option than combustion controls, SCR, or SCR plus combustion controls.

The cost effectiveness of adding SCR to the Hill boilers ranges from $3,900 per ton to $4,000 per ton of NOX and the total cost equals 1.9 million dollars ($1,900,000) annually and 57 million dollars ($57,000,000) over thirty (30) years. The cost effectiveness of SCR plus combustion controls ranges from $4,000 per ton to $4,100 per ton of NOX and the total cost equals 2.2 million dollars ($2,200,000) annually and 66 million dollars ($66,000,000) over thirty (30) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Additionally, reductions in NOX emissions are expected to have a negligible impact on regional haze. Therefore, Hawaiian Electric does not propose any NOX emissions reductions in addition to the Hawaiʻi RPS, EEPS, and the GHG ERP to meet the RHR requirements.

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[23] *Hawaiian Electric Companies' PSIP Update Report,* PUC Docket 2014-0183, December 23, 2016.

[24] *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

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. 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 Kanoelehua-Hill.

Table 5-1. Baseline PM_{10} Emissions

	PM_{10} Emissions		
Unit	**Primary Fuel Emissions Factor (lb/MMBtu) [A]**	**Adjusted Emission Factor (lb/MMBtu) [B]**	**(TPY) [C]**
Hill 5	0.0562	0.0562	24.7
Hill 6	0.0449	0.0450	32.4
D-11	0.0573	--	<0.1
D-15	0.0573	--	<0.1
D-16	0.0573	--	<0.1
D-17	0.0573	--	<0.1
CT-1	0.0113	--	<0.1
		Total	**57.2**

[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

PM_{10} emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in lower PM_{10} emissions than heavier residual oils. Distillate oils have lower ash and sulfur content than residual oil, therefore, producing less PM_{10} emissions.

Available PM_{10} control technologies for the boilers are:

- Post-Combustion Controls
  - Dry or Wet Electrostatic Precipitator (ESP)
  - Fabric Filters
  - Wet Scrubber
  - Cyclone
- Fuel Switching to a residual/distillate blended fuel or a distillate fuel
- Renewable Portfolio Standards (RPS)

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

Diesel engine generators D-11, D-15, D-16, and D-17 currently burn ULSD, and a four-factor analysis is not required for PM_{10}. CT-1 operates on a very limited basis, and post-combustion PM_{10} controls are not feasible for combustion turbines. Fuel switching from diesel to ULSD is not expected to significantly reduce PM_{10} emissions. Due to the limited operations of CT-1, 2017 PM_{10} emissions were less than 0.1

tons. Any reduction in PM_{10} emissions from CT-1 is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-1.

5.1.1. Post-Combustion Controls

PM_{10} emissions from residual oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, dry ESP, cyclones, and fabric filters are not good technological matches for the Hill boilers.

A wet ESP operates very similarly to a dry ESP, but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. The wet ESP utilizes water to collect and remove the particles and produces a waste-water product. Flue gas leaving the wet ESP will be saturated and may result in a visual steam plume. The estimated PM_{10} control efficiency is up to ninety percent for a wet ESP.[26] Wet ESP is a technically feasible option for control of PM_{10} for the Hill boilers.

In wet scrubbers PM_{10} is removed from flue gas when the gas stream is brought into contact with a scrubbing liquid using several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. The PM_{10} in the gas stream is captured in the scrubbing liquid. The PM_{10}-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for the Hill boilers is considered a technically feasible option. The estimated PM_{10} removal efficiency for a wet scrubber is fifty to sixty percent.[27]

5.1.2. Fuel Switching

Residual oil has inherent ash that contributes to the emissions of filterable PM_{10}. Distillate fuels have less ash and ultimately lower filterable PM_{10} emissions. Filterable PM_{10} emissions could be reduced by switching to a residual oil/distillate blend or to a distillate fuel. Section 1 discussed the option of fuel switching with respect to reducing SO_2 emissions. As discussed in Section 1, Hawaiian Electric has limited fuel options. Switching to a distillate fuel will result in the PM_{10} emissions reductions and is technically feasible. The PM_{10} four-factor analysis evaluates both options. Table 5-2 provides the control levels for fuel switching.

Table 5-2. PM_{10} Reduction from Fuel Switching

Fuel Scenario	AP-42 PM_{10} Emission Factors [A] (lb/MMBtu)	Percent PM_{10} Reduction from Fuel Switching [B]
Residual Oil	0.1540	--
Distillate (ULSD)	0.0236	85%
50/50 Blend	--	43%

[A] The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, 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.

5.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM_{10} emissions from Kanoelehua-Hill do not significantly contribute to regional haze. The low impact that Kanoelehua-Hill may have on haze is already being reduced through

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[26] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1

[27] Ibid.

conversion of electric generation to renewable energy sources as mandated by the RPS (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 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 Hawaii 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.

5.2. FOUR-FACTOR ANALYSIS

As discussed above, wet ESPs, wet scrubbers, and switching to distillate fuel are the best feasible options to reduce PM_{10} emissions. 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 wet ESPs, wet scrubbers, and switching to distillate fuel are discussed in the following sections.

5.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of wet ESPs, wet scrubbers, and switching to distillate fuel have been estimated. The cost effectiveness calculation is based on the following reduction in PM_{10} emissions:

- Wet Scrubbers – fifty percent,
- Switching to a residual oil/ULSD blend or to ULSD – forty-three percent to eighty-five percent, and
- Wet ESP – ninety percent.

Table 5-3 presents a summary of the cost effectiveness of wet scrubbers, switching to distillate fuel, and wet ESPs. The cost effectiveness ranges are:

- Wet Scrubbers - $10,000 per ton - $11,000 per ton and the total cost equals 300 thousand dollars ($300,000) annually and 9 million dollars ($9,000,000) over thirty (30) years,
- Switching to a residual oil/ULSD blend or to ULSD – exceeds $189,000 per ton and the total cost exceeds 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years, and
- Wet ESPs - $68,000 per ton - $92,00 per ton and the total cost equals 4.2 million dollars ($4,200,000) annually and 126 million dollars ($126,000,000) over thirty (30) years.

5.2.2. Time Necessary to Achieve Compliance

If the DOH determines that wet scrubbers or wet ESPs are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years. If the DOH determines that switching a distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

5.2.3. Energy and Non-Air Quality Environmental Impacts

ESPs, by design, apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a wastewater treatment plant. Further, the wastewater treatment process will generate a filter cake that would likely require landfilling.

5.2.4. Remaining Useful Life

A capital cost recovery period of thirty (30) years was used for the controls costing. However, Hawaiian Electric's PSIP[28], which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that Hill 5 boiler will be retired in 2027, and Hill 6 boiler will be retired in 2030. Although the plan is not expressly binding, this is a necessary step to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. These retirements will 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 PM10.

5.3. PARTICULATE MATTER CONCLUSION

The cost effectiveness of all the PM10 controls evaluated for the Hill boilers is more than $9,700 per ton, and for most controls and boilers is more than $67,500 per ton. The total cost of PM10 controls ranges from 300 thousand dollars ($300,000) annually and 9 million dollars ($9,000,000) over thirty (30) years to 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years. These costs are similar to the BART analysis conducted for the first planning period. For the first planning period, the EPA concluded that PM10 controls were not cost effective.[29]

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, Hawaiian Electric does not propose any PM10 emissions reductions in addition to the Hawai'i RPS, EEPS, and the GHG ERP to meet the RHR requirements.

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[28] *Hawaiian Electric Companies' PSIP Update Report,* PUC Docket 2014-0183, December 23, 2016.

[29] Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i, U.S. EPA Region 9, May 14, 2012

Table 5-3. PM_{10} Cost Effectiveness of Wet ESP, Wet Scrubber and Switching to Distillate Fuel

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Level of Control [B] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C,D] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	137,430	11,128
	Residual Oil/ULSD Blend [D]	24.7	43	14.1	10.6	2,002,327	188,525
	ULSD [D]	24.7	85	3.7	21.0	4,120,758	196,273
	Wet ESP	24.7	90	2.5	22.2	1,500,833	67,514
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	157,587	9,728
	Residual Oil/ULSD Blend [D]	32.4	43	18.5	13.9	3,285,807	235,846
	ULSD [D]	32.4	85	4.9	27.5	6,762,141	245,539
	Wet ESP	32.4	90	3.2	29.2	2,673,793	91,694

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

[B] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

[C] See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

6. TOTAL COST EFFECTIVENESS OF FUEL SWITCHING

Table 6-1 lists the cost per total combined tons of SO_2, NO_X, and PM_{10} reduced for fuel switching the boilers from residual oil to a residual oil/ULSD blend and ULSD. The cost effectiveness is determined by dividing the annual increase in fuel cost by the annual reduction in total SO_2, NO_X, and PM_{10} emissions. The total cost effectiveness of fuel switching is over $4,300 per ton of emissions and the total cost exceeds 5 million dollars ($5,000,000) annually and 150 million dollars ($150,000,000) over thirty (30) years.

Table 6-1. Total Cost Effectiveness of Fuel Switching

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Level of Control [B] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C,D] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	137,430	11,128
	Residual Oil/ULSD Blend [D]	24.7	43	14.1	10.6	2,002,327	188,525
	ULSD [D]	24.7	85	3.7	21.0	4,120,758	196,273
	Wet ESP	24.7	90	2.5	22.2	1,500,833	67,514
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	157,587	9,728
	Residual Oil/ULSD Blend [D]	32.4	43	18.5	13.9	3,285,807	235,846
	ULSD [D]	32.4	85	4.9	27.5	6,762,141	245,539
	Wet ESP	32.4	90	3.2	29.2	2,673,793	91,694

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

[B] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

[C] See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

APPENDIX A: DETAILED COSTING

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

Parameters/Costs	Equation	Hill 5	Hill 6
Boiler design capacity, mmBtu/hr (C)		197	249
Boiler Type		Wall	Tangential
2017 Annual Heat Input, MMBtu/yr (H)		878,441	1,441,517
Unit Size, kW (kW)		14,100	23,000
Unit Size, MW (MW)		14.1	23.0
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
Cost Index (CI) [A]			
a. 2019	607.5		
b. 2004	444.2		
Total Capital Investment [BC]			
TCI ($)	=$24/kW x kW x (300/MW)^0.359 x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Wall =$18/kW x kW x (300/MW)^0.359 x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Tangential	$1,387,123	$1,423,621
Direct Annual Operating Costs $/yr			
Variable O&M Costs [D]	=($0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Wall =$0.03 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10^6 Btu/mmBtu x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Tangential	$9,611	$5,914
Indirect Annual Costs, $/yr			
1. Fixed O&M Costs [E]	= $0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Wall = $0.27/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW)^0.359 x ($\mathrm{CI}_{2019}/\mathrm{CI}_{2004}$) - Tangential	$20,807	$21,354
2. Capital recovery	= Equipment CRF x TCI	$111,783	$114,724
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$142,201**	**$141,993**

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). Chemical Engineering Journal.

[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 Hawaii'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 Hawaii'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 Hawaii's remote location.

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

		Hill 5	Hill 6
MW		14.1	23.0
Baseline NOx Emission Rate (lb/MMBtu)		0.57	0.49
2017 Annual Heat Input, MMBtu/yr		878,441	1,441,517
Max Heat Input (MMBtu/hr)		197	249
Capital Recovery Factor (CRF)		0.08	0.08
Cost Index [A]			
2019	607.5		
1999	390.6		
B =	(lb/MMBtu)	0.57	0.49
C =	(%)	90	90
A =	(kW)	14,100	23,000
Z (Eq. 1) =		0.91	0.91
Capital Cost (Eq. 2)	($/kW)	$212	$178
Capital Cost (2019)	($)	$4,646,597	$6,369,287
Hawai'i Island Construction Cost Multiplier [B]		1.840	1.840
Hawai'i Island Capital Cost (2019)		$8,549,738	$11,719,489
Annualized Capital Cost	($/yr)	$688,993	$944,431
G =		0.51	0.66
H =	(MMBtu/hr)	197	249
D =	($/kW)	$330	$277
Fixed O&M[C] (Eq. 3)	($/yr)	$30,668	$42,037
Variable O&M Cost (Eq. 4)	($/yr)	$84,318	$145,403
Total Annual Cost	**($/yr)**	**$803,978**	**$1,131,872**

$$\boxed{Z = \left[(B/1.5)^{0.05}(C/100)^{0.4}\right]}$$ Equation 1

$$\boxed{D = 75\left\{300{,}000\frac{Z}{A}\right\}^{0\ 35}}$$ Equation 2

Where:

D = Capital cost ($/kW)
B = NO_X (lb/10^6 Btu) at the inlet of the SCR reactor
C = NO_X removal efficiency (%)
A = Plant capacity (kW)

$$\boxed{E = D \times A \times C}$$ Equation 3

Where:

E = Fixed O&M cost ($/yr)
D = Capital cost ($/kW) from Equation 1
A = Plant capacity (kW)
C = A constant, 0.0066 yr-1

$$\boxed{F = G\{225 \times [0.37B \times H \times (C/100) \times (8760/2000)] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A\}}$$ Equation 4

Where:

F = Variable O&M Cost ($/yr)
G = Annual capacity factor (expressed as a fraction)
B = Inlet NO_X (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
H = Heat input (MMBtu/hr)
C = NO_X removal efficiency; range of 80-95%
D = Capital cost ($/kW)
A = Plant capacity (kW)

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)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers*, EPA/600/R-01/087, October 2001. A 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). Chemical Engineering Journal.

[B] The Hawai'i Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016 to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead.*

[B] Fixed Costs include elements such as labor, station power, capital additions/improvements

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	Equation/Reference	Hill 5	Hill 6
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s)[1]	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM)[1]	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	ACFM*((68+460)/(Tstack+460))	33,596	73,261
m_{wv} (lb/min)	SCFM * MC * 18/385	188	411
m_a (lb/min)	SCFM * (1-MC) * 29/385	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	*h (Estimated from psychrometric chart)*	23.00	23.00
Q_{SAT}	h * ma	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	1.15*(150*Q_{SAT}^0.56)	$57,290	$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	$57,290	$88,652
Auxiliary Costs (A2)	A2 = 0.1*A1	$5,729	$8,865
Equipment Costs (A)	A = A1 + A2	$63,019	$97,517
Instrumentation	0.10 A	$6,302	$9,752
Sales taxes	0.03 A	$1,891	$2,926
Freight	0.05 A	$3,151	$4,876
Purchased Equipment cost, PEC	**B = 1.18 A**	**$74,363**	**$115,070**
Direct Installation Costs			
Foundation & supports	0.06 B	$4,462	$6,904
Handling & erection	0.40 B	$29,745	$46,028
Electrical	0.01 B	$744	$1,151
Piping	0.05 B	$3,718	$5,754
Insulation for ductwork	0.03 B	$2,231	$3,452
Painting	0.01 B	$744	$1,151
Direct Installation Costs, DIC	**0.56 B**	**$41,643**	**$64,439**
Total Direct Costs, TDC	**PEC + DIC**	**$116,006**	**$179,510**
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	$7,436	$11,507
Construction & field expenses	0.10 B	$7,436	$11,507
Contractor fees	0.10 B	$7,436	$11,507
Start-up	0.01 B	$744	$1,151
Performance test	0.01 B	$744	$1,151
Model study	--		
Contingencies	0.03B	$2,231	$3,452
Total Indirect Costs, IC	**0.35 B**	**$26,027**	**$40,275**
Cost Index[5]			
a. 2019	607.5		
b. 2002	395.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08	0.08
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$305,356**	**$472,514**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $20/hr	$43,200	$43,200
Supervisor	15% of operator	$6,480	$6,480
Maintenance			
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual ($20.00/hr, 7.5 h/wk, 44 wk/yr)	$6,600	$6,600
Material	100% of maintenance labor	$6,600	$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$62,880**	**$62,880**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$6,107	$9,450
Property tax	1% of Total Capital Investment	$3,054	$4,725
Insurance	1% of Total Capital Investment	$3,054	$4,725
Overhead	60% of total labor and material costs	$37,728	$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$24,608	$38,078
Total Indirect Annual Costs		**$74,550**	**$94,707**
Total Annual Cost		**$137,430**	**$157,587**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Hill 5	Hill 6
Average High Exhaust Flow Rate (m^3/s)[1]		26.5	48.1
Average High Exhaust Flow Rate (ACFM)[1]		56,135	101,845
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)[4]	ESCA = $-\ln(p)/w_e \times 5.080 \times Q$	2,091	3,794
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	$25.5/acfm	$1,431,451	$2,597,038
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$644,153	$1,168,667
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$2,075,604	$3,765,705
Instrumentation	0.10 A	$207,560	$376,570
Sales taxes	0.03 A	$62,268	$112,971
Freight	0.05 A	$103,780	$188,285
Purchased Equipment cost, PEC	**B = 1.18 A**	**$2,449,212**	**$4,443,531**
Direct Installation Costs			
Foundation & supports	0.04 B	$97,968	$177,741
Handling & erection	0.50 B	$1,224,606	$2,221,766
Electrical	0.08 B	$195,937	$355,483
Piping	0.01 B	$24,492	$44,435
Insulation for ductwork	0.02B	$48,984	$88,871
Painting	0.02B	$48,984	$88,871
Direct Installation Costs, DIC	**0.67 B**	**$1,640,972**	**$2,977,166**
Total Direct Costs, TDC	**PEC + DIC**	**$4,090,185**	**$7,420,697**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$489,842	$888,706
Construction & field expenses	0.20B	$489,842	$888,706
Contractor fees	0.10B	$244,921	$444,353
Start-up	0.01B	$24,492	$44,435
Performance test	0.01B	$24,492	$44,435
Model study	0.02B	$48,984	$88,871
Contingencies	0.03B	$73,476	$133,306
Total Indirect Costs, IC	**0.57B**	**$1,396,051**	**$2,532,813**
Cost Index[5]			
a. 2019	607.5		
b. 1999	390.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08	0.08
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41).**	**$11,945,836**	**$21,672,966**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	2hr/shift*2shifts/day*365 days/yr * $20/hr	$29,200	$29,200
Supervisor	15% of operator	$4,380	$4,380
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 = $4125	$4,125	$4,125
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$37,705**	**$37,705**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$238,917	$433,459
Property tax	1% of Total Capital Investment	$119,458	$216,730
Insurance	1% of Total Capital Investment	$119,458	$216,730
Overhead	60% of total labor and material costs	$22,623	$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$962,672	$1,746,546
Total Indirect Annual Costs		**$1,463,128**	**$2,636,088**
TOTAL ANNUAL COST		**$1,500,833**	**$2,673,793**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] Electricity cost form U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

[3] Water cost from Maui County (https://www.mauicounty.gov/216/Water-Charges) lowest general rate.

[4] For ESP Plate Area (Section 3.2.1):

p = 1 - (Control Efficiency %)
5.080 ft^2/kacfm = 1 (s/m)
w_e = effective migration velocity (m/s), assume w_e = 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficienc
Q = system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

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

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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

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[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.

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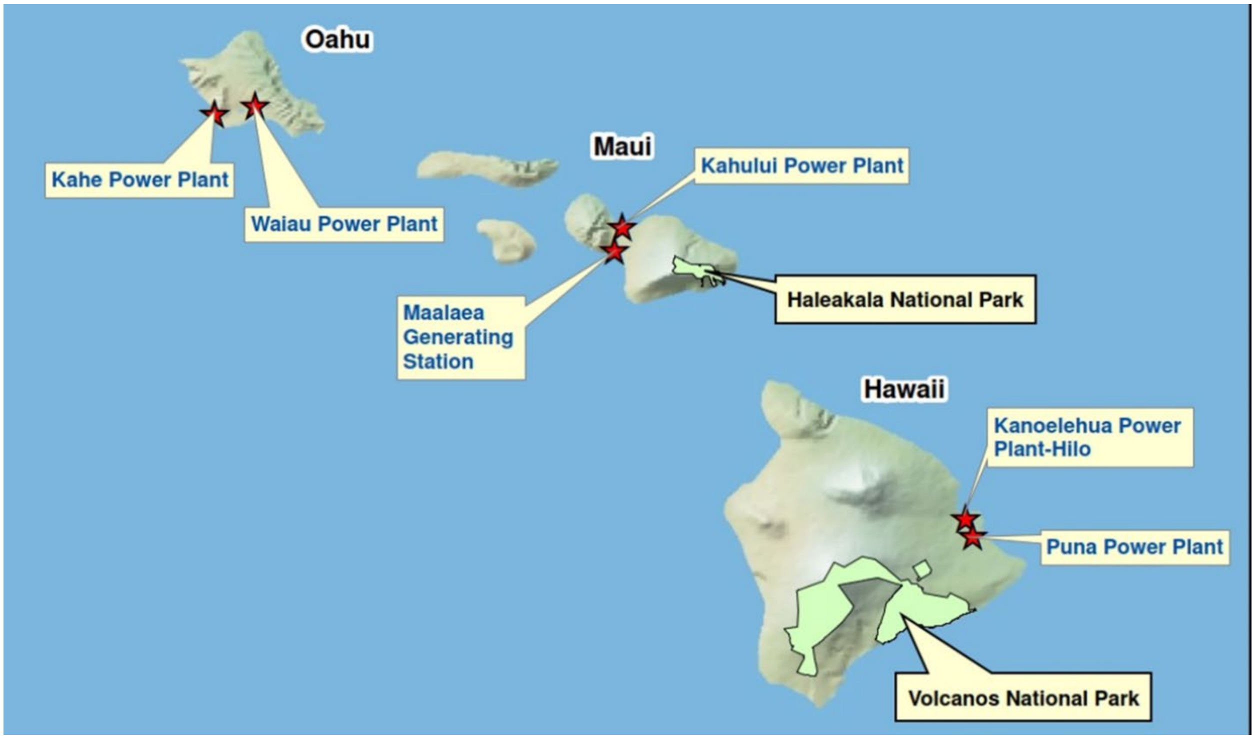
[2] Information on the volcanic SO_2 emissions in 2014 was provided by the EPA in their SO_2 National Ambient Air Quality Technical Support Document at EPA's 2016 SO_2 NAAQS TSD, at https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.

[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."* . . .

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[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.

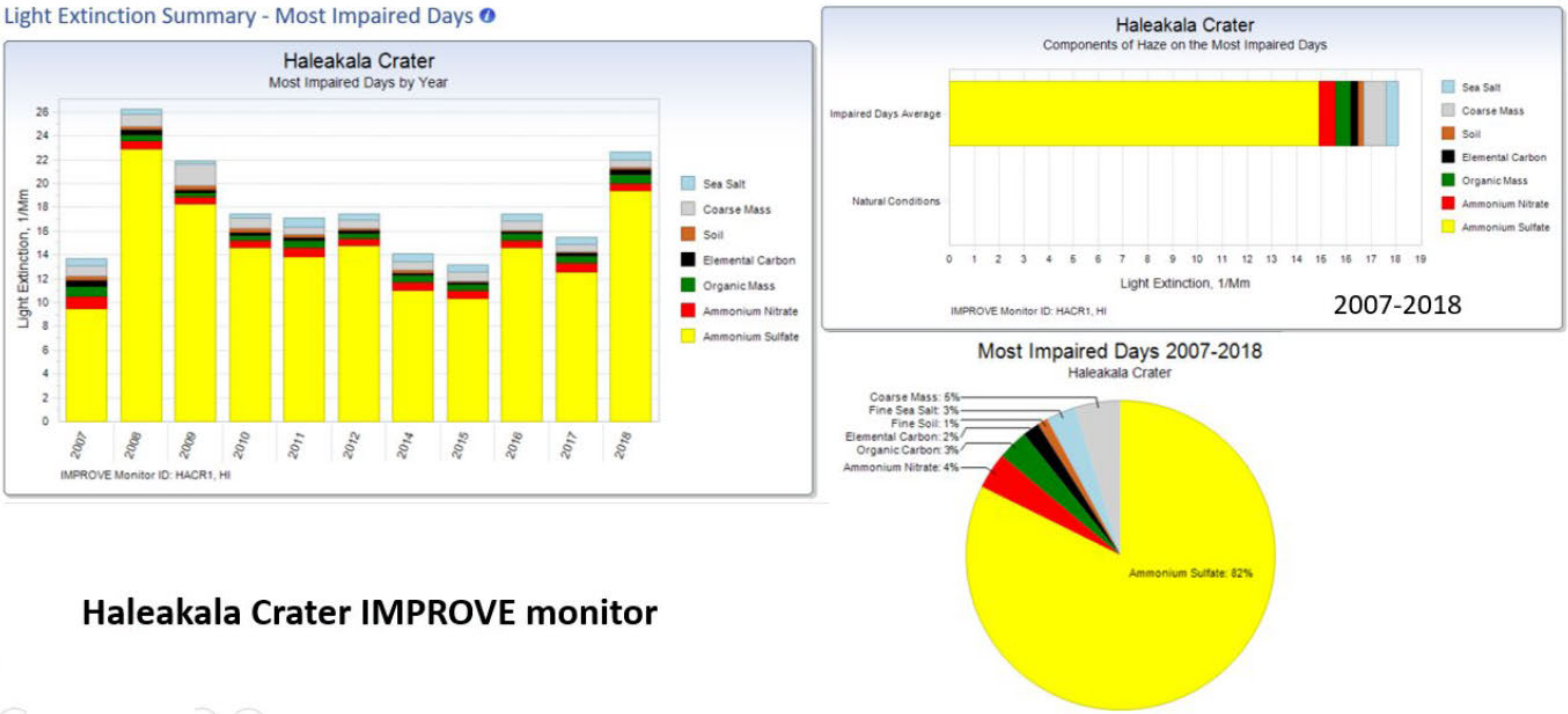
3. Nitrate Haze Composition Analysis

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



Haleakala Crater IMPROVE monitor

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

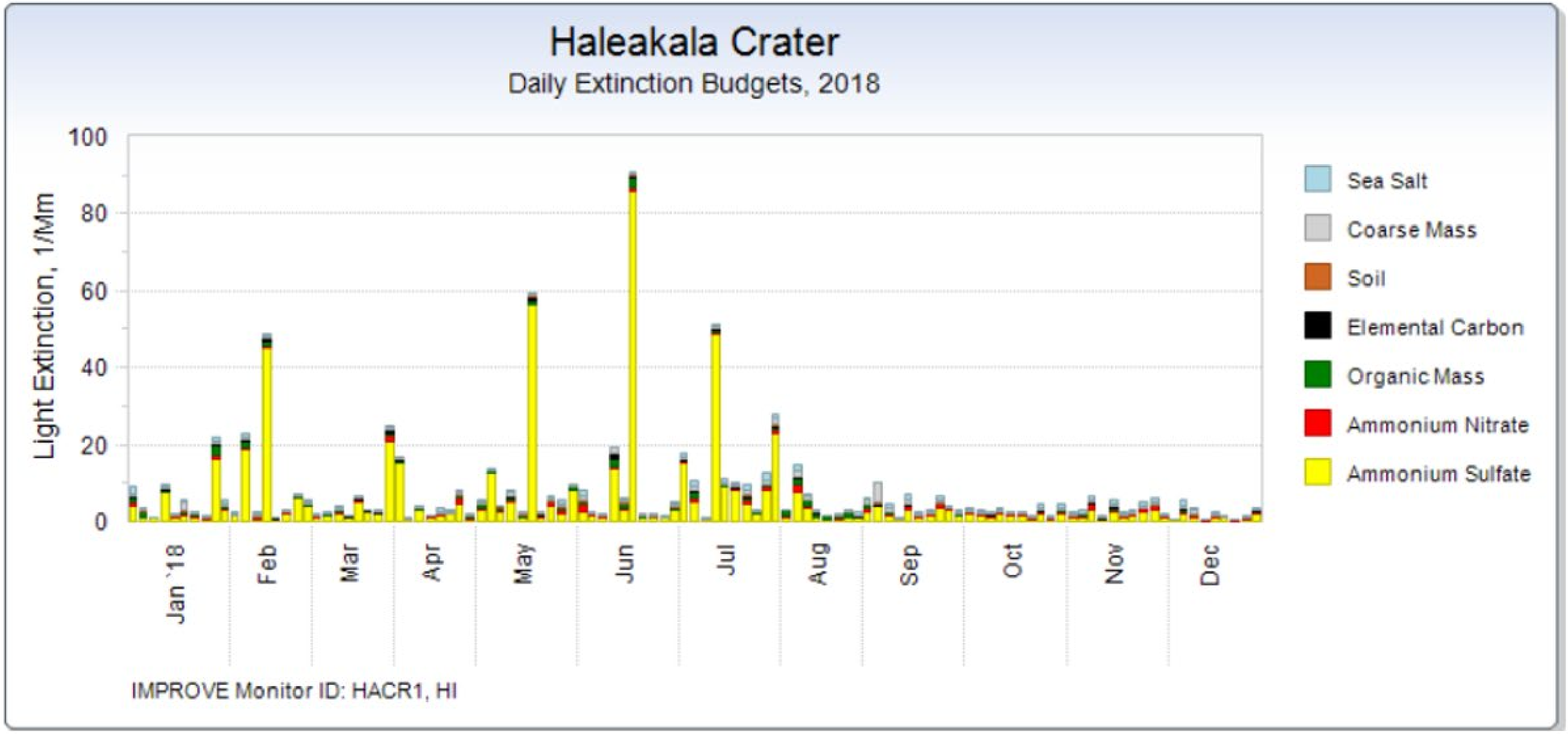
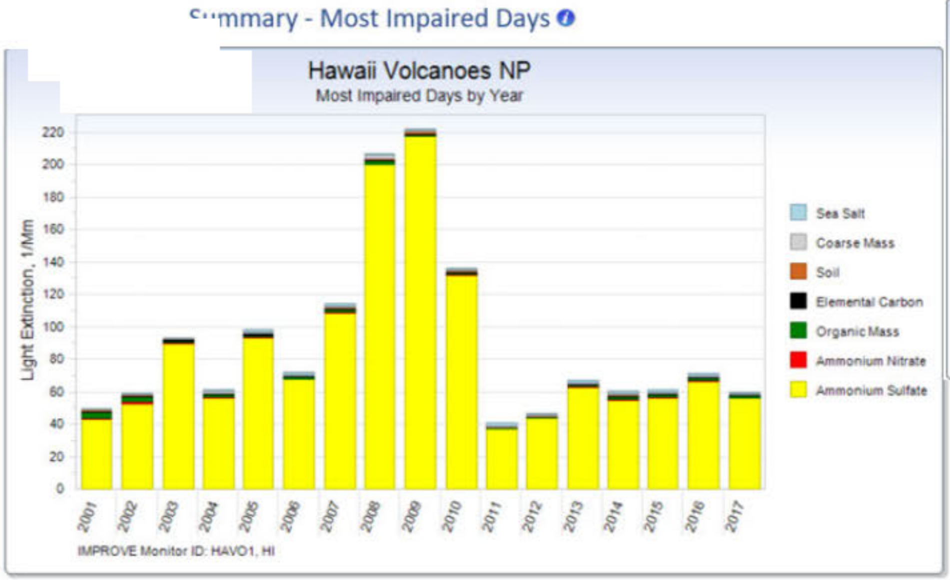
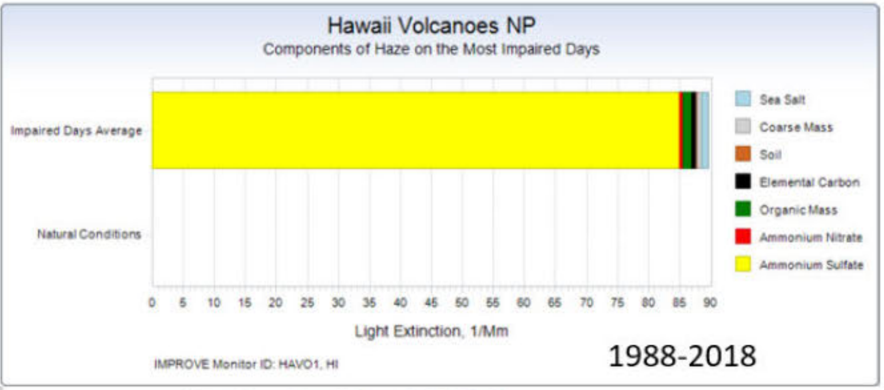
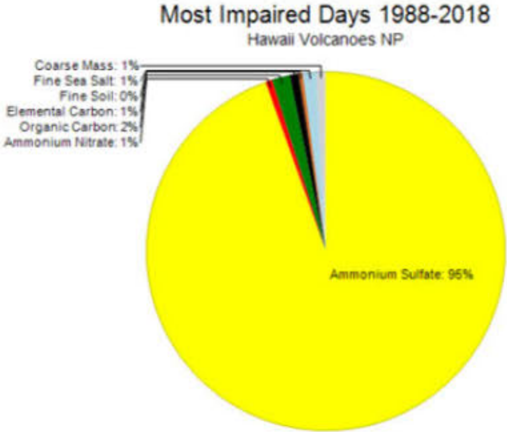


Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site



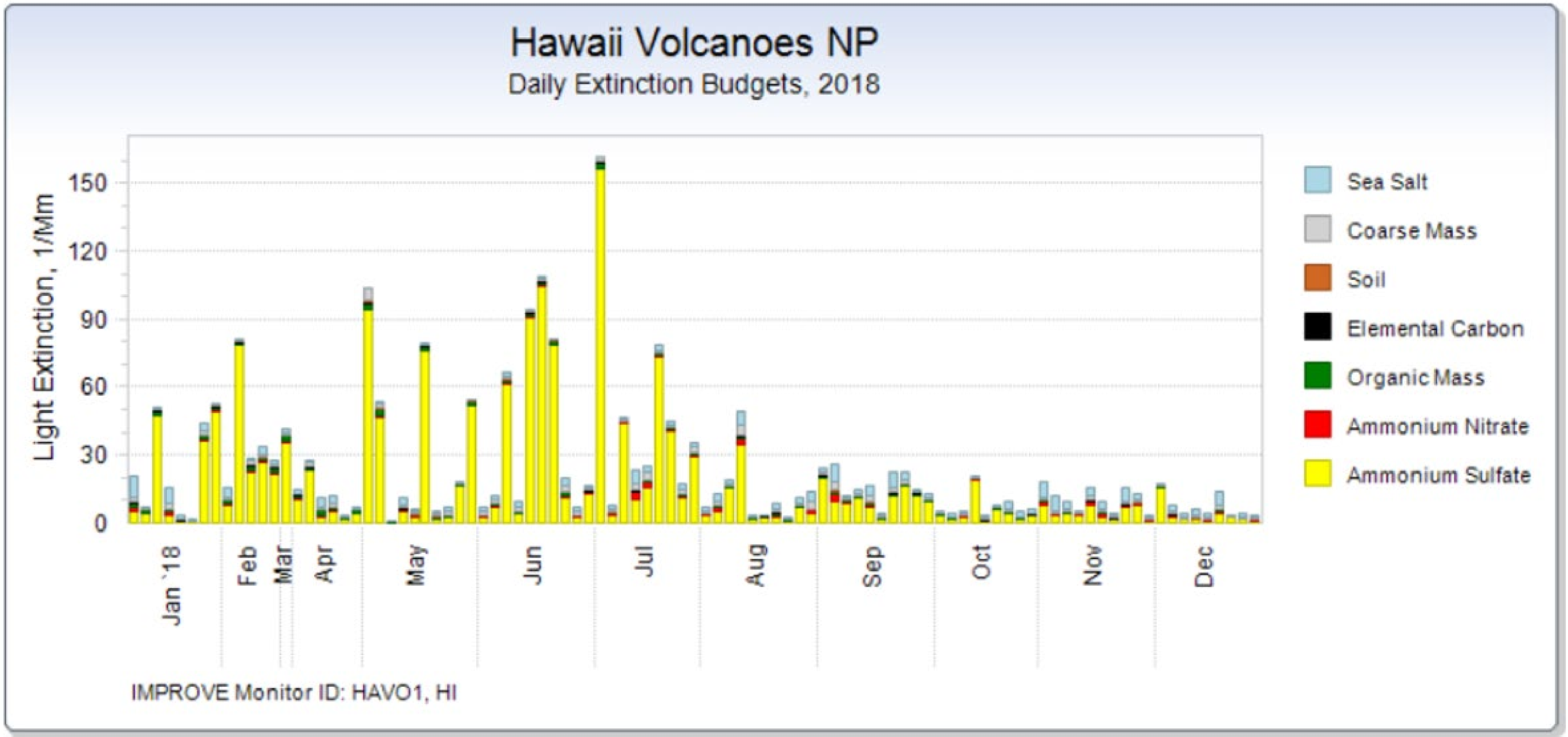


1988-2018



Hawaii Volcanoes NP IMPROVE monitor

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.

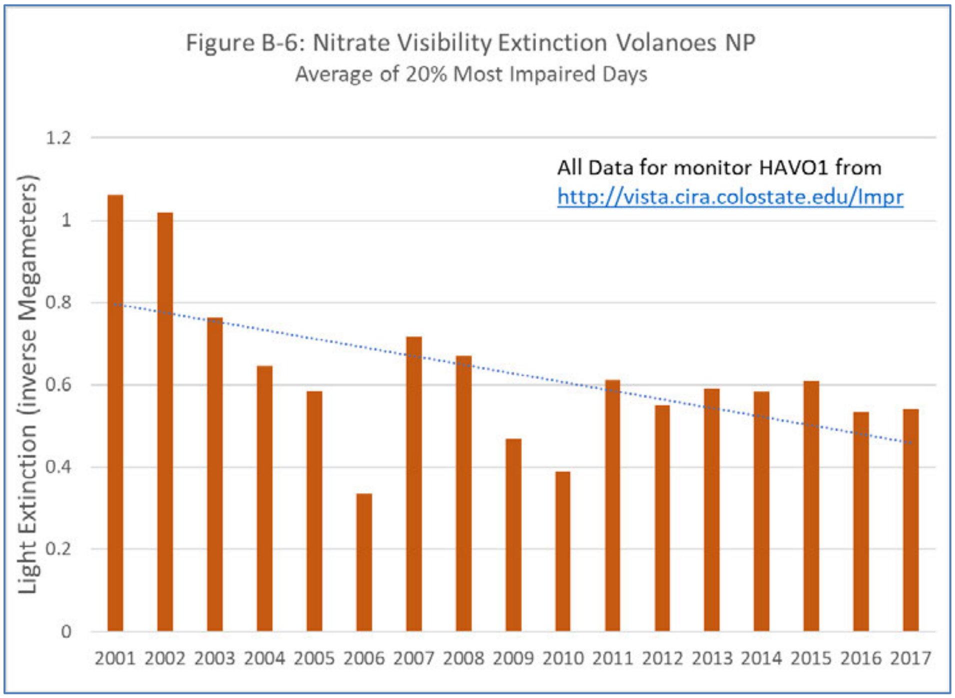


Figure B-6: Nitrate Visibility Extinction Volanoes NP

Average of 20% Most Impaired Days

All Data for monitor HAVO1 from http://vista.cira.colostate.edu/Impr

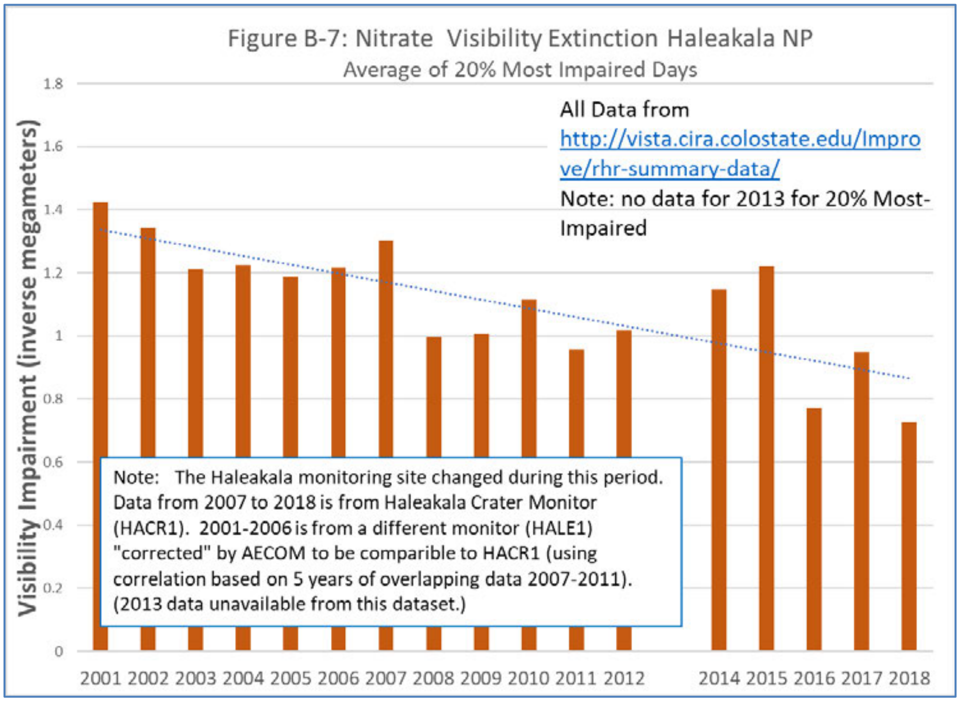


Figure B-7: Nitrate Visibility Extinction Haleakala NP

Average of 20% Most Impaired Days

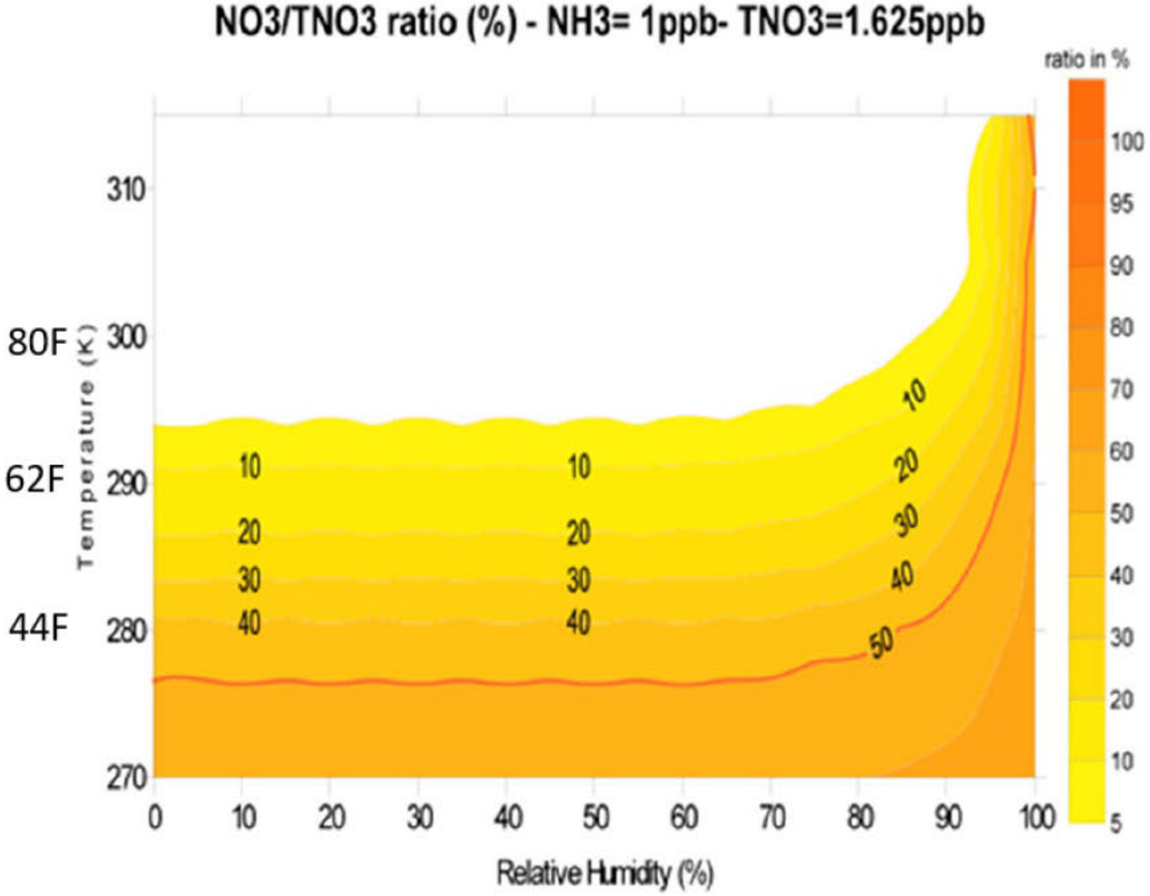
All Data from http://vista.cira.colostate.edu/Improve/rhr-summary-data/

Note: no data for 2013 for 20% Most-Impaired

Note: The Haleakala monitoring site changed during this period. Data from 2007 to 2018 is from Haleakala Crater Monitor (HACR1). 2001-2006 is from a different monitor (HALE1) "corrected" by AECOM to be comparible to HACR1 (using correlation based on 5 years of overlapping data 2007-2011). (2013 data unavailable from this dataset.)

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.

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[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.

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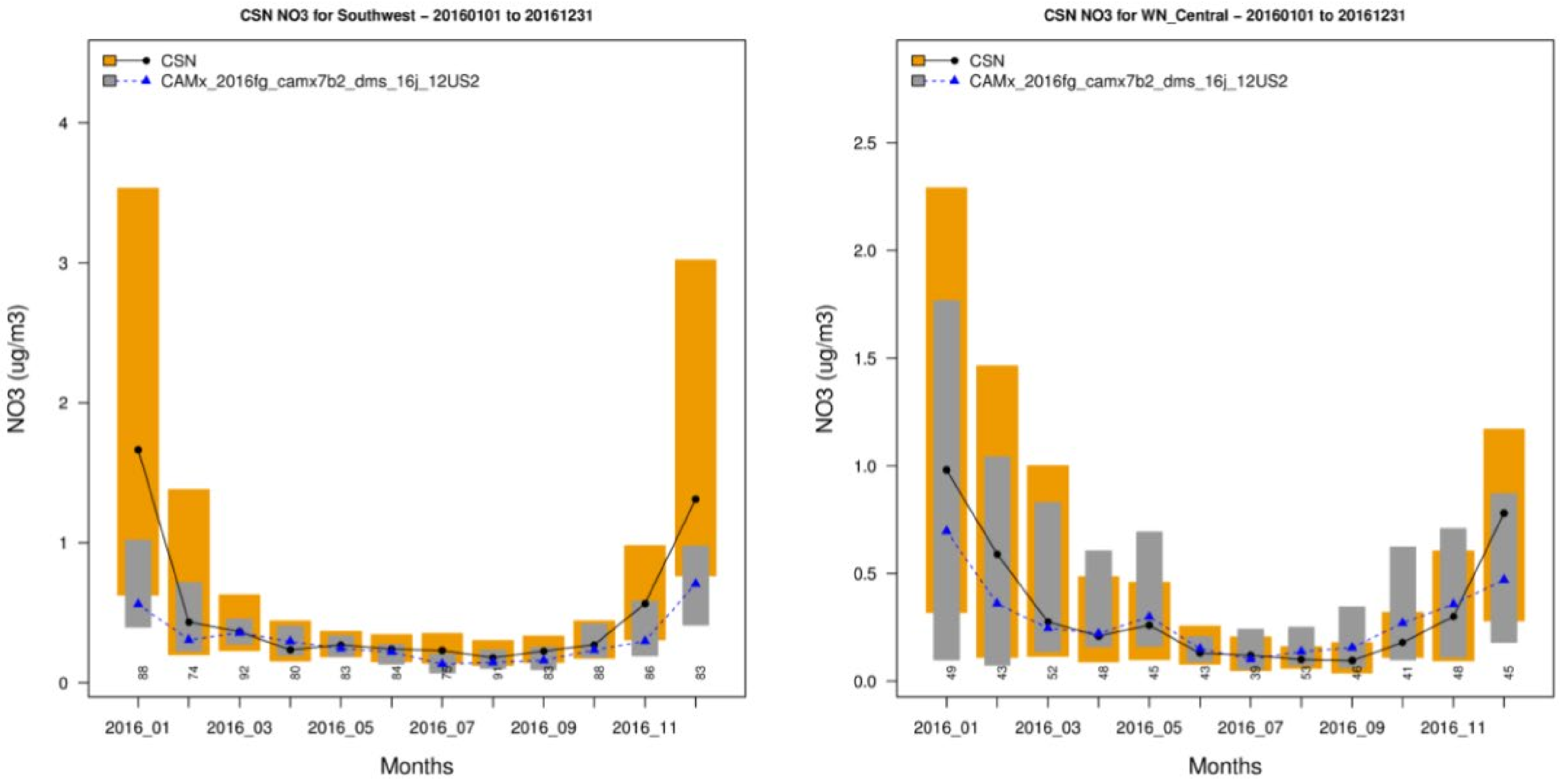
[8] Mather, T., 2004. A Volcanic Breath of Life? Chemistry World, 30 November 2004 Featured Article. https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article.

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

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[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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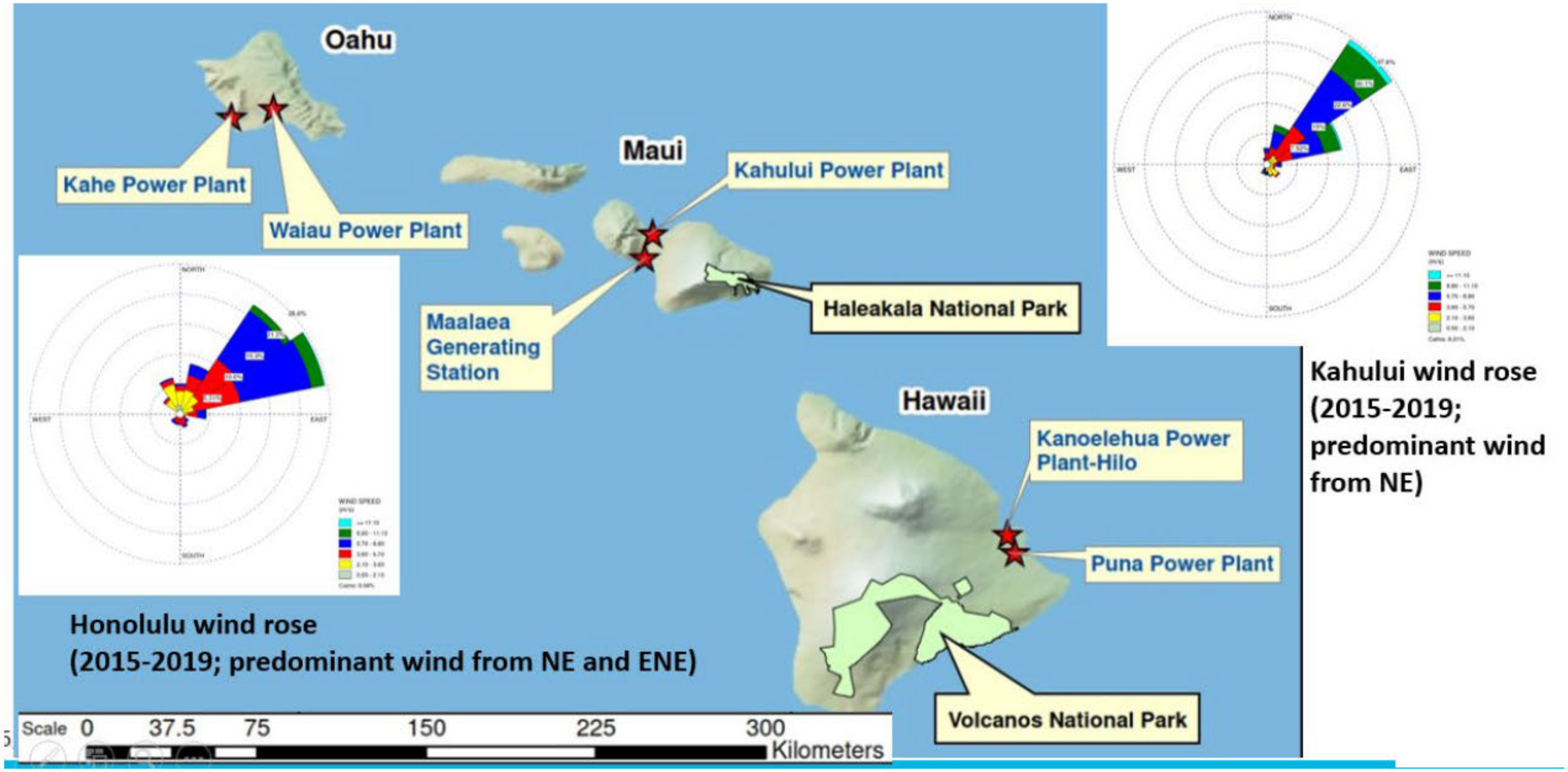
[10] https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf.

[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



Kahului wind rose (2015-2019; predominant wind from NE)

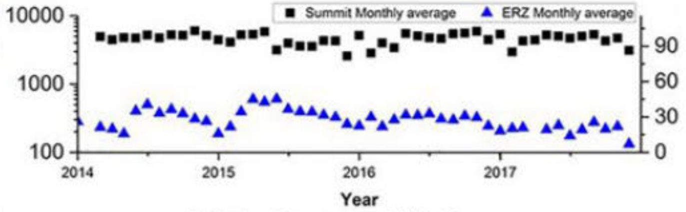
Honolulu wind rose (2015-2019; predominant wind from NE and ENE)

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 Hawaiʻi Island; all other sources in the state are not contributing to haze at the Class 1 areas.

- Implementation of Hawaiʻi'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 Hawaiʻi well before the year 2064. This Hawaiʻi 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 Hawaiʻi.

APPENDIX C: HAWAI‘I’S RENEWABLE PORTFOLIO STANDARDS CONTRIBUTION TO REGIONAL HAZE PROGRESS

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].

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[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 Hawai'i, 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 Hawai'i EGUs have made significant progress to date and have been ahead of the RPS interim targets.

Hawaiian Electric represents majority of Hawai'i'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.

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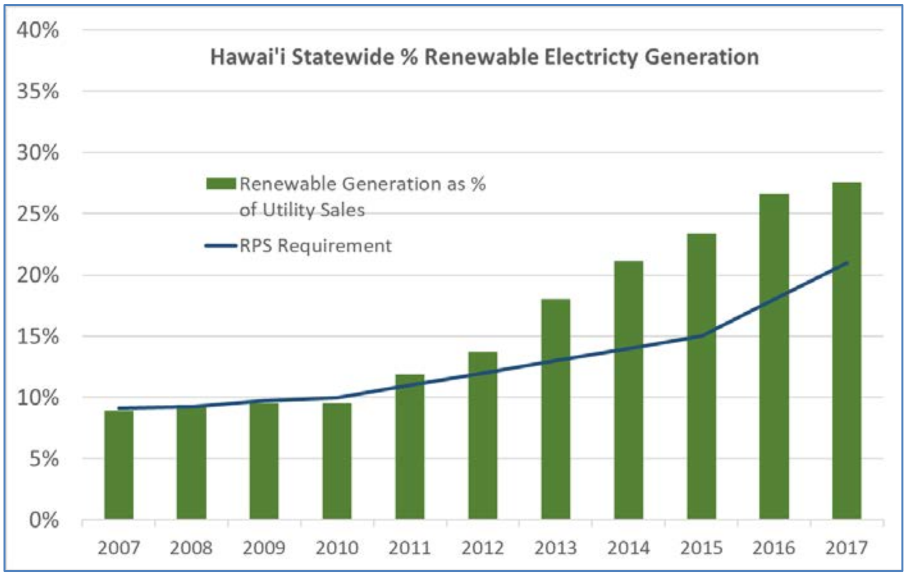
[2] "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i 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.

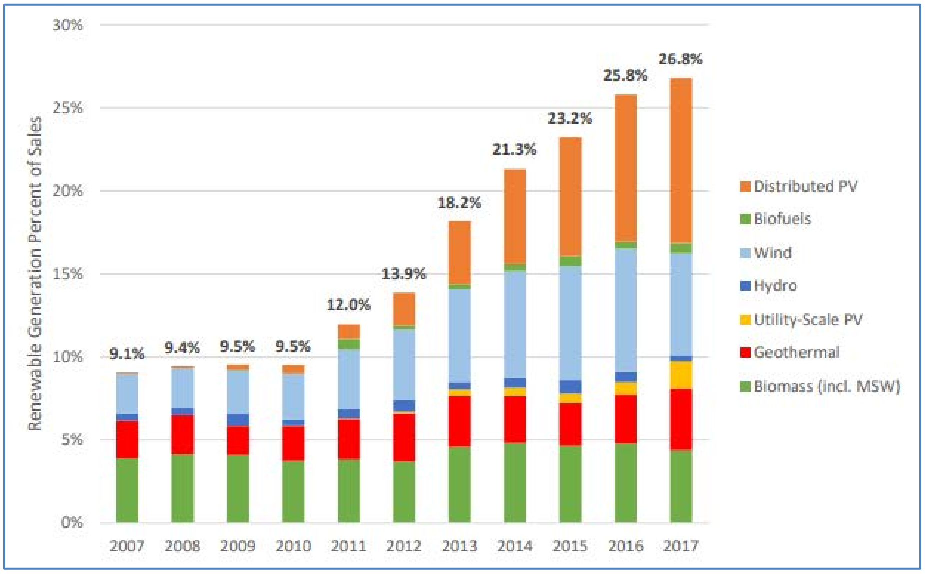
[3] *Hawai'i Public Utility Commission* (PUC), *"Report to the 2019 Legislature on Hawai'i's Renewable Portfolio Standards", Dec. 2018* https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

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]



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[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]

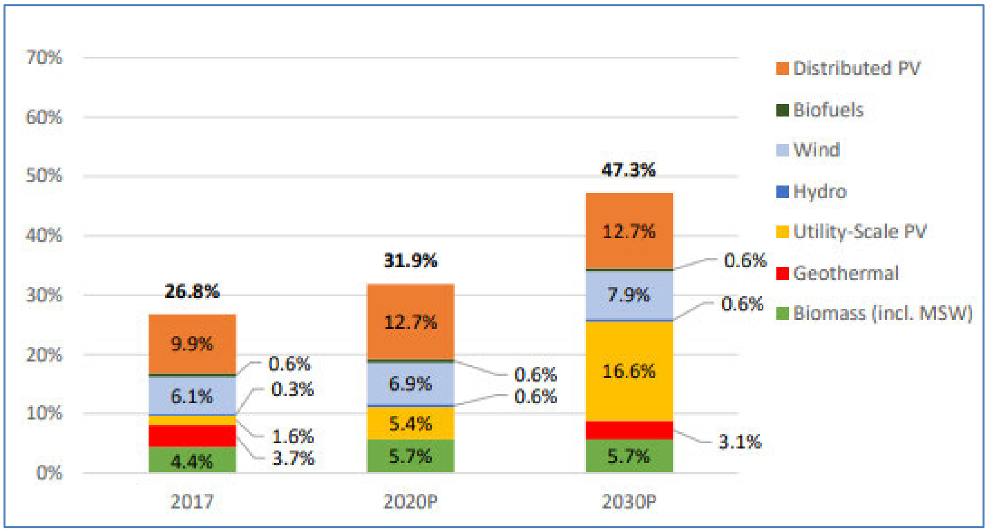

Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC’s 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric’s renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian 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.

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[5] PUC Dec. 2018 Report, page 2.

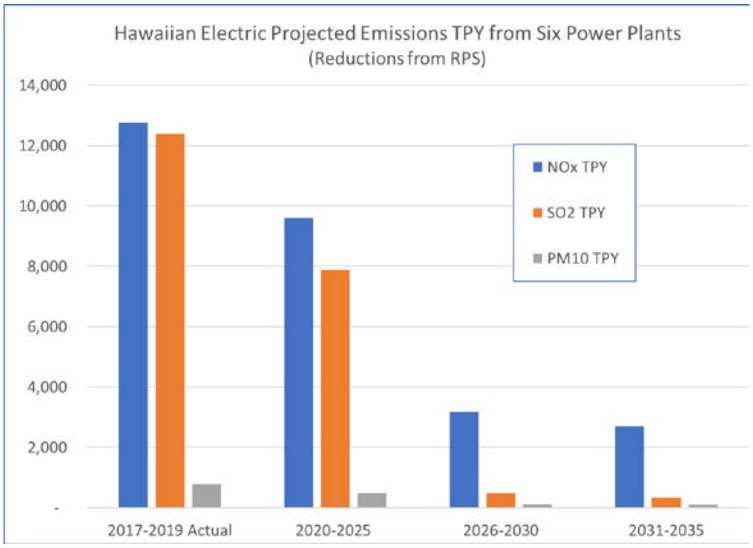
[6] PUC Dec. 2018 Report, Figure 2, page 16.

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.

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[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 D: FUEL COST

Appendix Table D-1. Residual High Sulfur Fuel Oil Cost

Date	Residual High Sulfur Fuel Oil [A]	
	($/BBL)	($/gal)
Jan-18	$57.52	$1.37
Feb-18	$63.81	$1.52
Mar-18	$68.78	$1.64
Apr-18	$61.32	$1.46
May-18	$63.74	$1.52
Jun-18	$69.26	$1.65
Jul-18	$75.84	$1.81
Aug-18	$75.73	$1.80
Sep-18	$76.56	$1.82
Oct-18	$76.16	$1.81
Nov-18	$76.50	$1.82
Dec-18	$85.79	$2.04
Jan-19	$74.99	$1.79
Feb-19	$62.02	$1.48
Mar-19	$62.73	$1.49
Apr-20	$71.38	$1.70
May-19	$75.30	$1.79
Jun-19	$72.39	$1.72
Jul-19	$70.54	$1.68
Aug-19	$62.92	$1.50
Sep-19	$62.28	$1.48
Oct-19	$59.26	$1.41
Nov-19	$59.61	$1.42
Dec-19	$58.81	$1.40
2018-19 Annual Average	**$68.47**	**$1.63**

[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/hawaii-island-energy-cost-filings)

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.

Appendix Table D-3. Diesel (0.4% Maximum Sulfur) Import Cost

Description	Value	Units
Platts 2018 Price [A]	85.12	$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	86.40	$/BBL
Freight [B]	5.51	$/BBL
Terminalling Fee [B]	2.00	$/BBL
Total ULSD Import Cost [C]	**93.91**	**$/BBL**
	2.24	**$/Gal**

[A] S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 0.25% S which is comparable to the current diesel supply. (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*

Hawaii Island Construction Cost Multiplier from 1.84 to 1

*** Equipment life of wet scrubbers were reassess at 30 years based on upcoming revision to the cost control manual.**

Table 3-1. 2017 Fuel Property and Fuel Usage and Baseline SO_2 Emissions

		2017 Annual Average Fuel Properties [A]			2017 Annual Fuel Usage [B]		SO_2 Emissions	
Unit	Primary Fuel	Sulfur Content	HHV (Btu/gal)	Density (lb/gal)	Volume (gal/yr)	Heat Input (MMBtu/yr)	(lb/MMBtu) [C]	(TPY) [D]
Hill 5	Residual Oil	1.69%	150,985	8.33	5,818,061	878,441	1.87	820.6
Hill 6	Residual Oil	1.69%	150,985	8.33	9,547,405	1,441,517	1.87	1,346.6
D-11	ULSD	0.0004%	138,564	7.10	1,607	223	4.10E-04	<0.1
D-15	ULSD	0.0004%	138,564	7.10	8,450	1,171	4.10E-04	<0.1
D-16	ULSD	0.0004%	138,564	7.10	2,951	409	4.10E-04	<0.1
D-17	ULSD	0.0004%	138,564	7.10	4,733	656	4.10E-04	<0.1
CT-1	Diesel	0.0540%	136,533	6.96	5,053	690	5.51E-02	<0.1
							Total	**2,167.2**

Permitted Heat Input (MMBtu/hr)	Permitted Output Nominal (MW)
197	14.1
249	23.0

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

[B] To account for ignition fuels and used oil usage the equivalent annual residual oil usage for Hill5 and Hill6 was calculated from the 2017 annual average fuel properties and reported SO_2 emissions.

[C] The SO_2 emission factors are based on 100% conversion of fuel sulfur to SO_2 and the calendar year 2017 annual average fuel density and higher heating value.

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

Table 4-1 Baseline NO_2 Emissions

		NO_X Emissions		
Unit	Primary Fuel	Primary Fuel Emissions Factor (lb/MMBtu) [A]	Adjusted Emission Factor (lb/MMBtu) [B]	(TPY) [C]
Hill 5	Residual Oil	0.572	0.573	251.5
Hill 6	Residual Oil	0.490	0.491	353.6
D-11	ULSD	3.200	--	0.4
D-15	ULSD	3.200	--	1.9
D-16	ULSD	3.200	--	0.7
D-17	ULSD	3.200	--	1.0
CT-1	Diesel	0.880	--	0.3
			Total	**609.3**

[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).

Table 5-1 Baseline PM_{10} Emissions

		PM_{10} Emissions		
Unit	Primary Fuel	Primary Fuel Emissions Factor (lb/MMBtu) [A]	Adjusted Emission Factor (lb/MMBtu) [B]	(TPY) [C]
Hill 5	Residual Oil	0.0562	0.0562	24.7
Hill 6	Residual Oil	0.0449	0.0450	32.4
D-11	ULSD	0.0573	--	<0.1
D-15	ULSD	0.0573	--	<0.1
D-16	ULSD	0.0573	--	<0.1
D-17	ULSD	0.0573	--	<0.1
CT-1	Diesel	0.0113	--	<0.1
			Total	**57.2**

[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).

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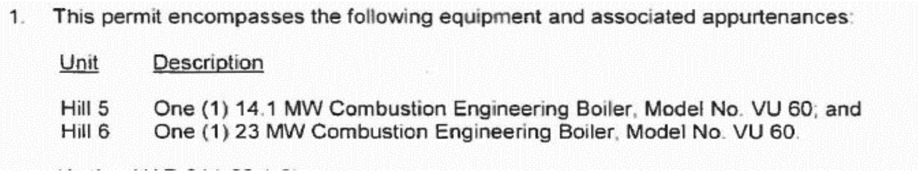
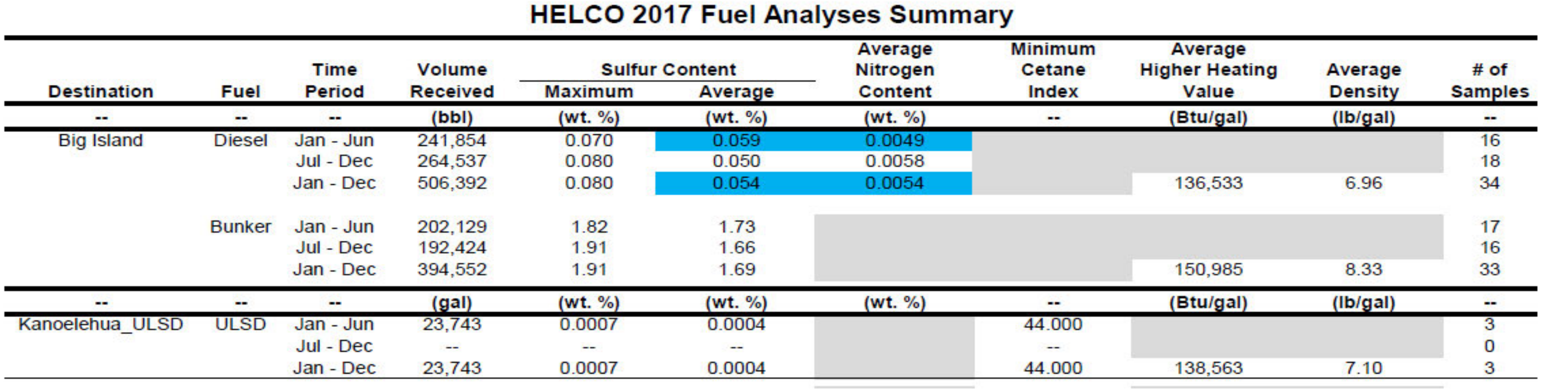
Company Records



1. This permit encompasses the following equipment and associated appurtenances:

Unit	Description
Hill 5	One (1) 14.1 MW Combustion Engineering Boiler, Model No. VU 60; and
Hill 6	One (1) 23 MW Combustion Engineering Boiler, Model No. VU 60.



HELCO 2017 Fuel Analyses Summary

Destination	Fuel	Time Period	Volume Received	Sulfur Content Maximum	Sulfur Content Average	Average Nitrogen Content	Minimum Cetane Index	Average Higher Heating Value	Average Density	# of Samples
--	--	--	(bbl)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Big Island	Diesel	Jan - Jun	241,854	0.070	0.059	0.0049				16
		Jul - Dec	264,537	0.080	0.050	0.0058				18
		Jan - Dec	506,392	0.080	0.054	0.0054		136,533	6.96	34
	Bunker	Jan - Jun	202,129	1.82	1.73					17
		Jul - Dec	192,424	1.91	1.66					16
		Jan - Dec	394,552	1.91	1.69			150,985	8.33	33
--	--	--	(gal)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Kanoelehua_ULSD	ULSD	Jan - Jun	23,743	0.0007	0.0004		44.000			3
		Jul - Dec	--	--	--		--			0
		Jan - Dec	23,743	0.0007	0.0004		44.000	138,563	7.10	3

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Table 3-2. SO_2 Cost Effectiveness of Switching to a Residual Oil/Diesel Blended Fuel

	Current Residual Oil [A]					Residual Oil/Distillate Blend (1.0% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	141,953	6,188,253	462.06	358.54	0.38	2,351,536	6,559
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	141,953	10,154,888	758.24	588.36	0.38	3,858,858	6,559

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

[B] Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted averge of the 2017 fuel HHV and density and contract fuel sulur limits (2.0% for residual oil and 0.4% for diesel).

[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 3-3. SO_2 Cost Effectiveness of Switching to Diesel

	Current Residual Oil [A]					Diesel (0.4% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	136,533	6,433,896	179.20	641.40	0.61	3,924,677	6,119
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	136,533	10,557,987	294.07	1,052.53	0.61	6,440,372	6,119

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

[B] Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).

[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 Switching to a Residual Oil/ULSD Blended Fuel

	Current Residual Oil [A]					Residual Oil/ULSD Blend (1.0% maximum Sulfur) [B]						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	144,774	6,067,657	468.21	352.39	0.33	2,002,327	5,682
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	144,774	9,956,991	768.33	578.27	0.33	3,285,807	5,682

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

[B] Based on a blend of 50.0% residual oil and 50.0% ULSD fuel and the weighted averge of the 2017 fuel HHV and density 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 3-5. SO_2 Cost Effectiveness of Switching to ULSD

	Current Residual Oil					ULSD (0.0015% maximum Sulfur)						
Unit	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)
Hill 5	1.69%	150,985	5,818,061	878,441	820.6	138,564	6,339,628	0.66	819.94	0.65	4,120,758	5,026
Hill 6	1.69%	150,985	9,547,405	1,441,517	1,346.6	138,564	10,403,294	1.08	1,345.52	0.65	6,762,141	5,026

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

[B] Based on 2017 average HHV and density and contract fuel sulfur limit.

[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).

Summary Calculations

	Total Cost	30-yr Cost
Residual Oil/Diesel (0.4% Max)	$6,000,000	$180,000,000
Diesel (0.4% Max)	$10,000,000	$300,000,000
Residual Oil/ULSD (0.0015% Max)	$5,000,000	$150,000,000
ULSD (0.0015% Max)	$11,000,000	$330,000,000

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Fuel Property Data and Fuel Cost Supporting Calculations

	2017 Annual Average [1]		Sulfur Limit	Fuel Cost [2]		Blend					Blend Cost
Fuel	(lb/gal)	(Btu/gal)	% S	$/BBL	$/Gal	Blend	(lb/gal)	(Btu/gal)	% S	SO_2 EF	$/Gal
Residual Oil	8.33	150,985	2.00%	68.46	1.63	37.5%	7.47	141,953	1.00%	1.052	2.01
Diesel	6.96	136,533	0.40%	94.08	2.24	62.5%					

[1] Calendar year 2017 annual average fuel properties from company records.

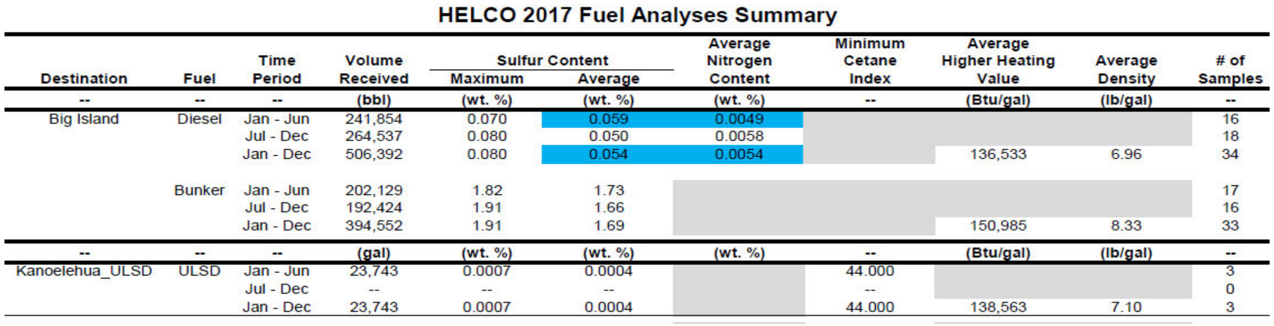
[2] See Appendix D for fuel cost.

Diesel Property Data and Fuel Cost Supporting Calculations

	2017 Annual Average [1]		Sulfur Limit	
Fuel	(lb/gal)	(Btu/gal)	% S	SO_2 EF
Diesel	6.96	136,533	0.40%	0.408

[1] Calendar year 2017 annual average fuel properties from company records.

Company Records



HELCO 2017 Fuel Analyses Summary

Destination	Fuel	Time Period	Volume Received	Sulfur Content Maximum	Sulfur Content Average	Average Nitrogen Content	Minimum Cetane Index	Average Higher Heating Value	Average Density	# of Samples
--	--	--	(bbl)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Big Island	Diesel	Jan - Jun	241,854	0.070	0.059	0.0049				16
		Jul - Dec	264,537	0.080	0.050	0.0058				18
		Jan - Dec	506,392	0.080	0.054	0.0054		136,533	6.96	34
	Bunker	Jan - Jun	202,129	1.82	1.73					17
		Jul - Dec	192,424	1.91	1.66					16
		Jan - Dec	394,552	1.91	1.69			150,985	8.33	33
--	--	--	(gal)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Kanoelehua_ULSD	ULSD	Jan - Jun	23,743	0.0007	0.0004		44.000			3
		Jul - Dec	--	--	--		--			0
		Jan - Dec	23,743	0.0007	0.0004		44.000	138,563	7.10	3

Fuel Property Data and Fuel Cost Supporting Calculations

	2017 Annual Average [1]		Sulfur Limit	Fuel Cost [2]		Blend					Blend Cost
Fuel	(lb/gal)	(Btu/gal)	% S	$/BBL	$/Gal	Blend	(lb/gal)	(Btu/gal)	% S	SO_2 EF	$/Gal
Residual Oil	8.33	150,985	2.00%	68.46	1.63	50.0%	7.72	144,774	1.00%	1.066	1.96
ULSD	7.10	138,564	0.0015%	95.76	2.28	50.0%					

[1] Calendar year 2017 annual average fuel properties from company records.

[2] See Appendix D for fuel cost.

Diesel Property Data and Fuel Cost Supporting Calculations

	2017 Annual Average [1]		Sulfur Limit	
Fuel	(lb/gal)	(Btu/gal)	% S	SO_2 EF
ULSD	7.10	138,564	0.0015%	0.0015

[1] Calendar year 2017 annual average fuel properties from company records.

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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)	Hill 5	Hill 6
Residual Oil	0.313	0.213	--	--
Distillate (ULSD)	0.171	0.171	45%	20%
50/50 Blend	--	--	23%	10%

[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.

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 - 0.20
SNCR	0.30 - 0.40	0.20 - 0.25
OFA	0.30 - 0.45	0.20 - 0.30
Fuel Switching	0.31 - 0.44	0.39 - 0.44

Original Submitted Spreadsheet

Table 4-4. NO_X Cost Effectiveness 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)
Hill 5	Residual Oil/ULSD Blend [D]	251.5	0.44	878,441	193.7	57.8	2,002,327	34,615
	ULSD [D]	251.5	0.31	878,441	138.3	113.2	4,120,758	36,410
	Combustion Controls	251.5	0.30	878,441	131.8	119.7	142,201	1,188
	SNCR	251.5	0.30	878,441	131.8	119.7	277,987	2,322
	SNCR+Combustion Controls	251.5	0.20	878,441	87.8	163.7	420,188	2,568
	SCR	251.5	0.10	878,441	43.9	207.6	803,978	3,873
	SCR+Combustion Controls	251.5	0.05	878,441	22.0	229.5	946,179	4,122
Hill 6	Residual Oil/ULSD Blend [D]	353.6	0.44	1,441,517	318.2	35.4	3,285,807	92,924
	ULSD [D]	353.6	0.39	1,441,517	282.9	70.7	6,762,141	95,619
	Combustion Controls	353.6	0.20	1,441,517	144.2	209.4	141,993	678
	SNCR	353.6	0.20	1,441,517	144.2	209.4	325,124	1,552
	SNCR+Combustion Controls	353.6	0.15	1,441,517	108.1	245.5	467,117	1,903
	SCR	353.6	0.10	1,441,517	72.1	281.5	1,131,872	4,021
	SCR+Combustion Controls	353.6	0.05	1,441,517	36.0	317.6	1,273,865	4,011

[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 fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

[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 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

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

Summary Calculations

Summary

Control Option	Cost Effectiveness ($/ton)	
	Minimum	Maximum
Residual Oil/ULSD Blend	$34,600	$92,900
ULSD	$36,400	$95,600
Combustion Controls	$700	$1,200
SNCR	$1,600	$2,300
SNCR+Combustion Controls	$1,900	$2,600
SCR	$3,900	$4,000
SCR+Combustion Controls	$4,000	$4,100
Total Cost	**Annual**	**30-yr**
Residual Oil/ULSD Blend	$5,000,000	$150,000,000
ULSD	$10,900,000	$327,000,000
Combustion Controls	$300,000	$9,000,000
SNCR	$600,000	$18,000,000
SNCR+Combustion Controls	$900,000	$27,000,000
SCR	$1,900,000	$57,000,000
SCR+Combustion Controls	$2,200,000	$66,000,000

Original Submitted Spreadsheet

Table 4-4. NO_X Cost Effectiveness 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)
Hill 5	Residual Oil/ULSD Blend [D]	251.5	0.44	878,441	193.7	57.8	2,002,327	34,615
	ULSD [D]	251.5	0.31	878,441	138.3	113.2	4,120,758	36,410
	Combustion Controls	251.5	0.30	878,441	131.8	119.7	125,823	1,051
	SNCR	251.5	0.30	878,441	131.8	119.7	225,571	1,884
	SNCR+Combustion Controls	251.5	0.20	878,441	87.8	163.7	351,394	2,147
	SCR	251.5	0.10	878,441	43.9	207.6	359,776	1,733
	SCR+Combustion Controls	251.5	0.05	878,441	22.0	229.5	485,599	2,116
Hill 6	Residual Oil/ULSD Blend [D]	353.6	0.44	1,441,517	318.2	35.4	3,285,807	92,924
	ULSD [D]	353.6	0.39	1,441,517	282.9	70.7	6,762,141	95,619
	Combustion Controls	353.6	0.20	1,441,517	144.2	209.4	125,184	598
	SNCR	353.6	0.20	1,441,517	144.2	209.4	266,746	1,274
	SNCR+Combustion Controls	353.6	0.15	1,441,517	108.1	245.5	391,930	1,597
	SCR	353.6	0.10	1,441,517	72.1	281.5	522,986	1,858
	SCR+Combustion Controls	353.6	0.05	1,441,517	36.0	317.6	648,170	2,041

[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 fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

[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 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

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

Summary Calculations

Summary

Control Option	Cost Effectiveness ($/ton)	
	Minimum	Maximum
Residual Oil/ULSD Blend	$34,600	$92,900
ULSD	$36,400	$95,600
Combustion Controls	$600	$1,100
SNCR	$1,300	$1,900
SNCR+Combustion Controls	$1,600	$2,100
SCR	$1,700	$1,900
SCR+Combustion Controls	$2,000	$2,100
Total Cost	**Annual**	**30-yr**
Residual Oil/ULSD Blend	$5,000,000	$150,000,000
ULSD	$10,900,000	$327,000,000
Combustion Controls	$300,000	$9,000,000
SNCR	$500,000	$15,000,000
SNCR+Combustion Controls	$700,000	$21,000,000
SCR	$900,000	$27,000,000
SCR+Combustion Controls	$1,100,000	$33,000,000

DOH-CAB Changed Spreadsheet

Table 5-2. PM_{10} Reduction from Fuel Switching

Fuel Scenario	AP-42 PM_{10} Emission Factors [A] (lb/MMBtu)	Percent PM_{10} Reduction from Fuel Switching [B]
Residual Oil	0.1540	--
Distillate (ULSD)	0.0236	85%
50/50 Blend	--	43%

[A] The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, 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.

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

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Level of Control [B] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C,D] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	137,430	11,128
	Residual Oil/ULSD Blend [D]	24.7	43	14.1	10.6	2,002,327	188,525
	ULSD [D]	24.7	85	3.7	21.0	4,120,758	196,273
	Wet ESP	24.7	90	2.5	22.2	1,500,833	67,514
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	157,587	9,728
	Residual Oil/ULSD Blend [D]	32.4	43	18.5	13.9	3,285,807	235,846
	ULSD [D]	32.4	85	4.9	27.5	6,762,141	245,539
	Wet ESP	32.4	90	3.2	29.2	2,673,793	91,694

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

[B] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

[C] See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Summary

Control Option	Cost Effectiveness ($/ton) Minimum	Maximum
Wet Scrubber	$10,000	$11,000
Residual Oil/ULSD Blend	$189,000	$236,000
ULSD	$196,000	$246,000
Wet ESP	$68,000	$92,000
Total Cost	**Annual**	**30-yr**
Wet Scrubber	300,000	9,000,000
Residual Oil/ULSD Blend	5,000,000	150,000,000
ULSD	10,900,000	327,000,000
Wet ESP	4,200,000	126,000,000

Table 5-2. PM_{10} Reduction from Fuel Switching

Fuel Scenario	AP-42 PM_{10} Emission Factors [A] (lb/MMBtu)	Percent PM_{10} Reduction from Fuel Switching [B]
Residual Oil	0.1540	--
Distillate (ULSD)	0.0236	85%
50/50 Blend	--	43%

[A] The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, 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.

Table 5-3. PM_{10} Cost Effectiveness Summary (20 Yrs Life)

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Level of Control [B] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C,D] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	133,824	10,836
	Residual Oil/ULSD Blend [D]	24.7	43	14.1	10.6	2,002,327	188,525
	ULSD [D]	24.7	85	3.7	21.0	4,120,758	196,273
	Wet ESP	24.7	90	2.5	22.2	1,359,783	61,169
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	152,008	9,383
	Residual Oil/ULSD Blend [D]	32.4	43	18.5	13.9	3,285,807	235,846
	ULSD [D]	32.4	85	4.9	27.5	6,762,141	245,539
	Wet ESP	32.4	90	3.2	29.2	2,417,889	82,918

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

[B] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

[C] See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Summary

Control Option	Cost Effectiveness ($/ton)	
	Minimum	Maximum
Wet Scrubber	$9,000	$11,000
Residual Oil/ULSD Blend	$189,000	$236,000
ULSD	$196,000	$246,000
Wet ESP	$61,000	$83,000
Total Cost	**Annual**	**30-yr**
Wet Scrubber	300,000	9,000,000
Residual Oil/ULSD Blend	5,000,000	150,000,000
ULSD	10,900,000	327,000,000
Wet ESP	3,800,000	114,000,000

DOH-CAB Changed Spreadsheet (20 Yrs Life)

Table 5-2. PM_{10} Reduction from Fuel Switching

Fuel Scenario	AP-42 PM_{10} Emission Factors [A] (lb/MMBtu)	Percent PM_{10} Reduction from Fuel Switching [B]
Residual Oil	0.1540	--
Distillate (ULSD)	0.0236	85%
50/50 Blend	--	43%

[A] The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, 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.

Table 5-3. PM_{10} Cost Effectiveness Summary (30 Yrs Life)

Unit	Control Option	2017 PM_{10} Emissions [A] (tpy)	Level of Control [B] (%)	Controlled PM_{10} Emissions (tpy)	PM_{10} Reduced (ton/yr)	Total Annual Cost [C,D] ($/yr)	Cost Effectiveness ($/ton)
Hill 5	Wet Scrubber	24.7	50	12.4	12.4	128,909	10,438
	Residual Oil/ULSD Blend [D]	24.7	43	14.1	10.6	2,002,327	188,525
	ULSD [D]	24.7	85	3.7	21.0	4,120,758	196,273
	Wet ESP	24.7	90	2.5	22.2	1,359,783	61,169
Hill 6	Wet Scrubber	32.4	50	16.2	16.2	144,401	8,914
	Residual Oil/ULSD Blend [D]	32.4	43	18.5	13.9	3,285,807	235,846
	ULSD [D]	32.4	85	4.9	27.5	6,762,141	245,539
	Wet ESP	32.4	90	3.2	29.2	2,417,889	82,918

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

[B] Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

[C] See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

[D] Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to a residual oil/ULSD blend or ULSD are listed since it's a more cost-effective SO_2 solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Summary

Control Option	Cost Effectiveness ($/ton)	
	Minimum	Maximum
Wet Scrubber	$9,000	$10,000
Residual Oil/ULSD Blend	$189,000	$236,000
ULSD	$196,000	$246,000
Wet ESP	$61,000	$83,000
Total Cost	**Annual**	**30-yr**
Wet Scrubber	300,000	9,000,000
Residual Oil/ULSD Blend	5,000,000	150,000,000
ULSD	10,900,000	327,000,000
Wet ESP	3,800,000	114,000,000

DOH-CAB Changed Spreadsheet (30 Yrs Life)

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)
Hill 5	Residual Oil/ULSD Blend	352.4	57.8	10.6	420.9	$2,002,327	$4,758
	ULSD	819.9	113.2	21	954.1	$4,120,758	$4,319
Hill 6	Residual Oil/ULSD Blend	578.3	35.4	13.9	627.6	$3,285,807	$5,236
	ULSD	1,345.50	70.7	27.5	1,443.80	$6,762,141	$4,684

[A] The SO_2, NO_X, and PM_{10} reduced are from Tables 3-4 and 3-5, Table 4-4, and Table 5-3, respectively.

[B] fuel switching are based on 2019 dollars.

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

Parameters/Costs	Equation	Hill 5	Hill 6
Boiler design capacity, mmBtu/hr (C)		197	249
Boiler Type		Wall	Tangential
2017 Annual Heat Input, MMBtu/yr (H)		878,441	1,441,517
Unit Size, kW (kW)		14,100	23,000
Unit Size, MW (MW)		14.1	23.0
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
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	$1,387,123	$1,423,621
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	$9,611	$5,914
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	$20,807	$21,354
2. Capital recovery	= Equipment CRF x TCI	$111,783	$114,724
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$142,201**	**$141,993**

Life	Interest %
30	7

A mill is equal to 1/1,000 of a U.S. dollar, or 1/10 of one cent. Mills per kilowatthour (kWh) equals dollars per megawatthour (mWh). To convert mills per kWh to cents per kWh, divide mills per kWh by 10.

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). Chemical Engineering Journal.

[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 Hawaii'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 Hawaii'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 Hawaii's remote location.

Original Submitted Spreadsheet

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

Parameters/Costs	Equation	Hill 5	Hill 6
Boiler design capacity, mmBtu/hr (C)		197	249
Boiler Type		Wall	Tangential
2017 Annual Heat Input, MMBtu/yr (H)		878,441	1,441,517
Unit Size, kW (kW)		14,100	23,000
Unit Size, MW (MW)		14.1	23.0
Capital recovery factor			
a. Equipment CRF, 20-yr life, 3.25% interes	= [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	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	$1,387,123	$1,423,621
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	$9,611	$5,914
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	$20,807	$21,354
2. Capital recovery	= Equipment CRF x TCI	$95,405	$97,915
Total Annual Cost $/yr	=Direct Annual Costs + Indirect Annual Costs	**$125,823**	**$125,184**

Life	Interest %
20	3.25

A mill is equal to 1/1,000 of a U.S. dollar, or 1/10 of one cent. Mills per kilowatthour (kWh) equals dollars per megawatthour (mWh). To convert mills per kWh to cents per kWh, divide mills per kWh by 10.

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). Chemical Engineering Journal.

[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 Hawaii'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 Hawaii'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 Hawaii's remote location.

DOH-CAB Changed Spreadsheet

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

		Hill 5	Hill 6
MW		14.1	23.0
Baseline NOx Emission Rate (lb/MMBtu)		0.57	0.49
2017 Annual Heat Input, MMBtu/yr		878,441	1,441,517
Max Heat Input (MMBtu/hr)		197	249
Capital Recovery Factor (CRF)		0.08	0.08
Cost Index [A]			
2019	607.5		
1999	390.6		
B =	(lb/MMBtu)	0.57	0.49
C =	(%)	90	90
A =	(kW)	14,100	23,000
Z (Eq. 1) =		0.91	0.91
Capital Cost (Eq. 2)	($/kW)	$212	$178
Capital Cost (2019)	($)	$4,646,597	$6,369,287
Hawai‘i Island Construction Cost Multiplier [B]		1.840	1.840
Hawai‘i Island Capital Cost (2019)		$8,549,738	$11,719,489
Annualized Capital Cost	($/yr)	$688,993	$944,431
G =		0.51	0.66
H =	(MMBtu/hr)	197	249
D =	($/kW)	$330	$277
Fixed O&M[C] (Eq. 3)	($/yr)	$30,668	$42,037
Variable O&M Cost (Eq. 4)	($/yr)	$84,318	$145,403
Total Annual Cost	**($/yr)**	**$803,978**	**$1,131,872**

$$\boxed{Z = \left[(B/1.5)^{0.05}(C/100)^{0.4}\right]}$$ Equation 1

$$\boxed{D = 75\left\{300{,}000\,\frac{Z}{A}\right\}^{0\ 35}}$$ Equation 2

Where:

D = Capital cost ($/kW)
B = NO_X (lb/10^6 Btu) at the inlet of the SCR reactor
C = NO_X removal efficiency (%)
A = Plant capacity (kW)

$$\boxed{E = D \times A \times C}$$ Equation 3

Where:

E = Fixed O&M cost ($/yr)
D = Capital cost ($/kW) from Equation 1
A = Plant capacity (kW)
C = A constant, 0.0066 yr-1

$$\boxed{F = G\{225 \times [0.37B \times H \times (C/100) \times (8760/2000)] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A\}}$$ n 4

Where:

F = Variable O&M Cost ($/yr)
G = Annual capacity factor (expressed as a fraction)
B = Inlet NO_X (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
H = Heat input (MMBtu/hr)
C = NO_X removal efficiency; range of 80-95%
D = Capital cost ($/kW)
A = Plant capacity (kW)

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

CRF = 0.08

Life	Interest %
30	7

Where:

I = Interest Rate (7% interest)
a = Equipment life (30 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers* EPA/600/R-01/087 October 2001. A 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). Chemical Engineering Journal.

[B] The Hawai i Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016 to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead*

[B] Fixed Costs include elements such as labor station power capital additions/improvements

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

			Hill 5	**Hill 6**
MW			14.1	23
Baseline NOx Emission Rate (lb/MMBtu)			0.57	0.49
2017 Annual Heat Input, MMBtu/yr			878,441	1,441,517
Max Heat Input (MMBtu/hr)			197	249
Capital Recovery Factor (CRF)			0.05	0.05
Cost Index [A]				
	2019	607.5		
	1999	390.6		
B	(lb/MMBtu)		0.57	0.49
C	(%)		90	90
A	(kW)		14,100	23,000
Z (Eq. 1)			0.91	0.91
Capital Cost (Eq. 2)	($/kW)		$212	$178
Capital Cost (2019)	($)		$4,646,597	$6,369,287
Hawai'i Island Construction Cost Multiplier [B]			1	1
Hawai'i Island Capital Cost (2019)			$4,646,597	$6,369,287
Annualized Capital Cost	($/yr)		$244,791	$335,545
G			0.51	0.66
H	(MMBtu/hr)		197	249
D	($/kW)		$330	$277
Fixed O&M[C] (Eq. 3)	($/yr)		$30,668	$42,037
Variable O&M Cost (Eq. 4)	($/yr)		$84,318	$145,403
Total Annual Cost	**($/yr)**		**$359,776**	**$522,986**

$$\boxed{Z = \left[(B/1.5)^{0.05}(C/100)^{0.4}\right]}$$ on 1

$$\boxed{D = 75\left\{300{,}000\,\frac{Z}{A}\right\}^{0.35}}$$ on 2

Where:

D	Capital cost ($/kW)
B	NO_X (lb/10^6 Btu) at the inlet of the SCR reactor
C	NO_X removal efficiency (%)
A	Plant capacity (kW)

$$\boxed{E = D \times A \times C}$$

Equation 3

Where:

E	Fixed O&M cost ($/yr)
D	Capital cost ($/kW) from Equation 1
A	Plant capacity (kW)
C	A constant, 0.0066 yr-1

$$\boxed{F = G\{225 \times [0.37B \times H \times (C/100) \times (8760/2000)] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A\}}$$

Equation 4

Where:

F	Variable O&M Cost ($/yr)
G	Annual capacity factor (expressed as a fraction)
B	Inlet NO_X (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
H	Heat input (MMBtu/hr)
C	NO_X removal efficiency; range of 80-95%
D	Capital cost ($/kW)
A	Plant capacity (kW)

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

		Life	Interest %
CRF	0.05	30	3.25

Where:

I	Interest Rate (3.25% interest)
a	Equipment life (30 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers* EPA/600/R-01/087 October 2001. A 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). Chemical Engineering Journal.

[B] The Hawai'i Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans Mechanical Cost Data 2016 to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead*
labor station power capital

DOH-CAB Changed Spreadsheet

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	**Equation/Reference**	**Hill 5**	**Hill 6**
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s)[1]	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM)[1]	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	ACFM*((68+460)/(Tstack+460))	33,596	73,261
m_{wv} (lb/min)	SCFM * MC * 18/385	188	411
m_a (lb/min)	SCFM * (1-MC) * 29/385	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	*h (Estimated from psychrometric chart)*	23.00	23.00
Q_{SAT}	h * ma	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	1.15*(150*Q_{SAT}^0.56)	$57,290	$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	$57,290	$88,652
Auxiliary Costs (A2)	A2 = 0.1*A1	$5,729	$8,865
Equipment Costs (A)	A = A1 + A2	$63,019	$97,517
Instrumentation	0.10 A	$6,302	$9,752
Sales taxes	0.03 A	$1,891	$2,926
Freight	0.05 A	$3,151	$4,876
Purchased Equipment cost, PEC	**B = 1.18 A**	**$74,363**	**$115,070**
Direct Installation Costs			
Foundation & supports	0.06 B	$4,462	$6,904
Handling & erection	0.40 B	$29,745	$46,028
Electrical	0.01 B	$744	$1,151
Piping	0.05 B	$3,718	$5,754
Insulation for ductwork	0.03 B	$2,231	$3,452
Painting	0.01 B	$744	$1,151
Direct Installation Costs, DIC	**0.56 B**	**$41,643**	**$64,439**
Total Direct Costs, TDC	**PEC + DIC**	**$116,006**	**$179,510**
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	$7,436	$11,507
Construction & field expenses	0.10 B	$7,436	$11,507
Contractor fees	0.10 B	$7,436	$11,507
Start-up	0.01 B	$744	$1,151
Performance test	0.01 B	$744	$1,151
Model study	--		
Contingencies	0.03B	$2,231	$3,452
Total Indirect Costs, IC	**0.35 B**	**$26,027**	**$40,275**
Cost Index[5]			
a. 2019	607.5		
b. 2002	395.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	0.08	0.08
	#NAME?		
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$305,356**	**$472,514**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $20/hr	$43,200	$43,200
Supervisor	15% of operator	$6,480	$6,480
Maintenance	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual		
Labor	($20.00/hr, 7.5 h/wk, 44 wk/yr)	$6,600	$6,600
Material	100% of maintenance labor	$6,600	$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$62,880**	**$62,880**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$6,107	$9,450
Property tax	1% of Total Capital Investment	$3,054	$4,725
Insurance	1% of Total Capital Investment	$3,054	$4,725
Overhead	60% of total labor and material costs	$37,728	$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$24,608	$38,078

Original Submitted Spreadsheet

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Total Indirect Annual Costs		**$74,550**	**$94,707**
Total Annual Cost		**$137,430**	**$157,587**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] From Chemical Engineering Plant Cost Index (CEPCI)

Company Records

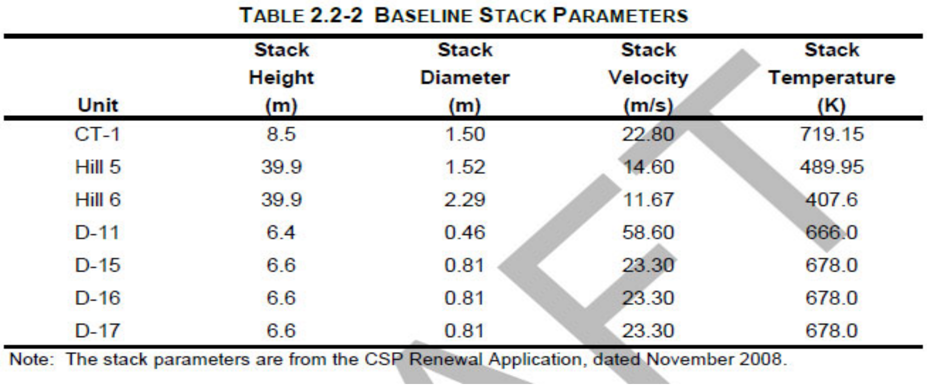

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (20 Yrs Life)

Parameters/Costs	Equation/Reference	Hill 5	Hill 6
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s)[1]	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM)[1]	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	ACFM*((68+460)/(Tstack+460))	33,596	73,261
m_{wv} (lb/min)	SCFM * MC * 18/385	188	411
m_a (lb/min)	SCFM * (1-MC) * 29/385	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	*h (Estimated from psychrometric chart)*	23.00	23.00
Q_{SAT}	h * ma	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	1.15*(150*Q_{SAT}^0.56)	$57,290	$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	$57,290	$88,652
Auxiliary Costs (A2)	A2 = 0.1*A1	$5,729	$8,865
Equipment Costs (A)	A = A1 + A2	$63,019	$97,517
Instrumentation	0.10 A	$6,302	$9,752
Sales taxes	0.03 A	$1,891	$2,926
Freight	0.05 A	$3,151	$4,876
Purchased Equipment cost, PEC	**B = 1.18 A**	**$74,363**	**$115,070**
Direct Installation Costs			
Foundation & supports	0.06 B	$4,462	$6,904
Handling & erection	0.40 B	$29,745	$46,028
Electrical	0.01 B	$744	$1,151
Piping	0.05 B	$3,718	$5,754
Insulation for ductwork	0.03 B	$2,231	$3,452
Painting	0.01 B	$744	$1,151
Direct Installation Costs, DIC	**0.56 B**	**$41,643**	**$64,439**
Total Direct Costs, TDC	**PEC + DIC**	**$116,006**	**$179,510**
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	$7,436	$11,507
Construction & field expenses	0.10 B	$7,436	$11,507
Contractor fees	0.10 B	$7,436	$11,507
Start-up	0.01 B	$744	$1,151
Performance test	0.01 B	$744	$1,151
Model study	--		
Contingencies	0.03B	$2,231	$3,452
Total Indirect Costs, IC	**0.35 B**	**$26,027**	**$40,275**
Cost Index[5]			
a. 2019	607.5		
b. 2002	395.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	0.07	0.07
	#NAME?		
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999})** **(Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$305,356**	**$472,514**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $20/hr	$43,200	$43,200
Supervisor	15% of operator	$6,480	$6,480
Maintenance			
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual ($20.00/hr, 7.5 h/wk, 44 wk/yr)	$6,600	$6,600
Material	100% of maintenance labor	$6,600	$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$62,880**	**$62,880**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$6,107	$9,450
Property tax	1% of Total Capital Investment	$3,054	$4,725
Insurance	1% of Total Capital Investment	$3,054	$4,725
Overhead	60% of total labor and material costs	$37,728	$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$21,002	$32,499

DOH-CAB Changed Spreadsheet (20 Yrs Life)

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (20 Yrs Life)

Total Indirect Annual Costs		**$70,944**	**$89,128**
Total Annual Cost		**$133,824**	**$152,008**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] From Chemical Engineering Plant Cost Index (CEPCI)

Company Records

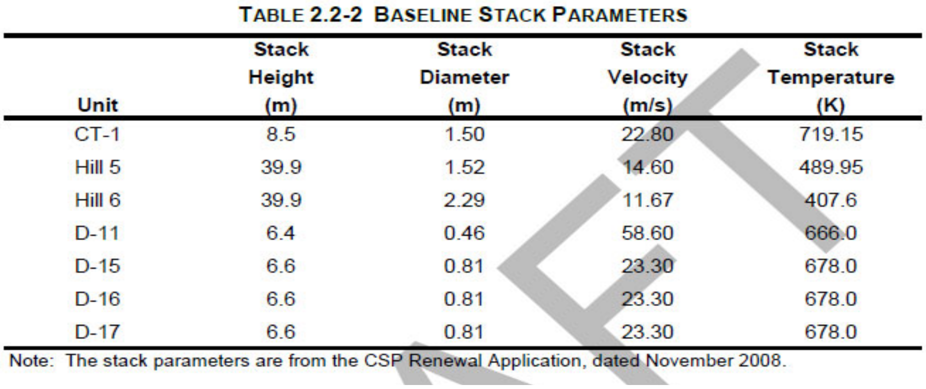

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (30 Yrs Life)

Parameters/Costs	Equation/Reference	Hill 5	Hill 6
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s)[1]	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM)[1]	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	ACFM*((68+460)/(Tstack+460))	33,596	73,261
m_{wv} (lb/min)	SCFM * MC * 18/385	188	411
m_a (lb/min)	SCFM * (1-MC) * 29/385	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	*h (Estimated from psychrometric chart)*	23.00	23.00
Q_{SAT}	h * ma	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	1.15*(150*Q_{SAT}^0.56)	$57,290	$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	$57,290	$88,652
Auxiliary Costs (A2)	A2 = 0.1*A1	$5,729	$8,865
Equipment Costs (A)	A = A1 + A2	$63,019	$97,517
Instrumentation	0.10 A	$6,302	$9,752
Sales taxes	0.03 A	$1,891	$2,926
Freight	0.05 A	$3,151	$4,876
Purchased Equipment cost, PEC	**B = 1.18 A**	**$74,363**	**$115,070**
Direct Installation Costs			
Foundation & supports	0.06 B	$4,462	$6,904
Handling & erection	0.40 B	$29,745	$46,028
Electrical	0.01 B	$744	$1,151
Piping	0.05 B	$3,718	$5,754
Insulation for ductwork	0.03 B	$2,231	$3,452
Painting	0.01 B	$744	$1,151
Direct Installation Costs, DIC	**0.56 B**	**$41,643**	**$64,439**
Total Direct Costs, TDC	**PEC + DIC**	**$116,006**	**$179,510**
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	$7,436	$11,507
Construction & field expenses	0.10 B	$7,436	$11,507
Contractor fees	0.10 B	$7,436	$11,507
Start-up	0.01 B	$744	$1,151
Performance test	0.01 B	$744	$1,151
Model study	--		
Contingencies	0.03B	$2,231	$3,452
Total Indirect Costs, IC	**0.35 B**	**$26,027**	**$40,275**
Cost Index[5]			
a. 2019	607.5		
b. 2002	395.6		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	0.05	0.05
	a. Equipment CRF, 30 yr life, 3.25% interest		
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$305,356**	**$472,514**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $20/hr	$43,200	$43,200
Supervisor	15% of operator	$6,480	$6,480
Maintenance			
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual ($20.00/hr, 7.5 h/wk, 44 wk/yr)	$6,600	$6,600
Material	100% of maintenance labor	$6,600	$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$62,880**	**$62,880**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$6,107	$9,450
Property tax	1% of Total Capital Investment	$3,054	$4,725
Insurance	1% of Total Capital Investment	$3,054	$4,725
Overhead	60% of total labor and material costs	$37,728	$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$16,087	$24,893

DOH-CAB Changed Spreadsheet

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (30 Yrs Life)

Total Indirect Annual Costs		**$66,029**	**$81,521**
Total Annual Cost		**$128,909**	**$144,401**

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.
[2] From Chemical Engineering Plant Cost Index (CEPCI)

Company Records

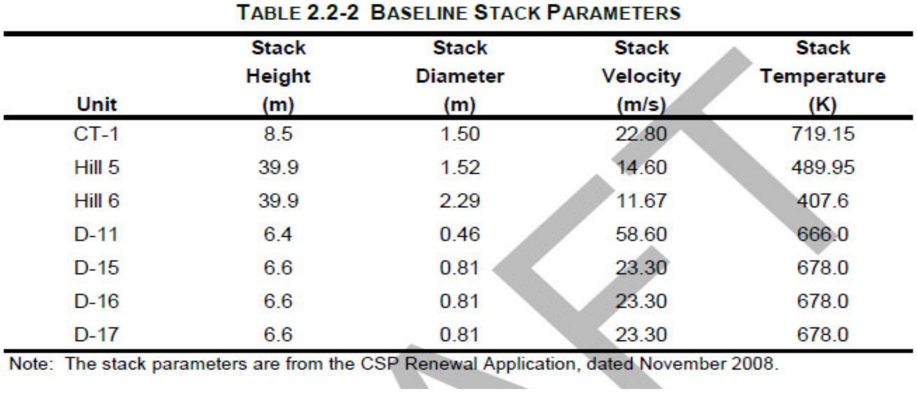

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

DOH-CAB Changed Spreadsheet

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Hill 5	Hill 6
Average High Exhaust Flow Rate (m^3/s)[1]		26.5	48.1
Average High Exhaust Flow Rate (ACFM)[1]		56,135	101,845
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)	ESCA -ln(p)/w_e × 5.080 × Q	2,091	3,794
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	$25.5/acfm	$1,431,451	$2,597,038
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$644,153	$1,168,667
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$2,075 604	$3,765,705
Instrumentation	0.10 A	$207,560	$376,570
Sales taxes	0.03 A	$62,268	$112,971
Freight	0.05 A	$103,780	$188,285
Purchased Equipment cost, PEC	**B = 1.18 A**	**$2,449,212**	**$4,443,531**
Direct Installation Costs			
Foundation & supports	0.04 B	$97,968	$177,741
Handling & erection	0.50 B	$1,224 606	$2,221,766
Electrical	0.08 B	$195,937	$355,483
Piping	0.01 B	$24,492	$44,435
Insulation for ductwork	0.02B	$48,984	$88,871
Painting	0.02B	$48,984	$88,871
Direct Installation Costs, DIC	**0.67 B**	**$1,640,972**	**$2,977,166**
Total Direct Costs, TDC	**PEC + DIC**	**$4,090,185**	**$7,420,697**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$489,842	$888,706
Construction & field expenses	0.20B	$489,842	$888,706
Contractor fees	0.10B	$244,921	$444,353
Start-up	0.01B	$24,492	$44,435
Performance test	0.01B	$24,492	$44,435
Model study	0.02B	$48,984	$88,871
Contingencies	0.03B	$73,476	$133,306
Total Indirect Costs, IC	**0.57B**	**$1,396,051**	**$2,532,813**
Cost Index[5]			
a. 2019	607.5		
b. 1999	390.6		
Capital recovery factor (CRF)	CRF [I x (1+i)^a]/[(1+i)^a - 1], where I interest rate, a equipment life	0.08	0.08
	a. Equipment CRF, 30-yr life, 7% interest		
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41).**	**$11,945,836**	**$21,672,966**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	2hr/shift*2shifts/day*365 days/yr * $20/hr	$29,200	$29,200
Supervisor	15% of operator	$4,380	$4,380
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 $4125	$4,125	$4,125
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$37,705**	**$37,705**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$238,917	$433,459
Property tax	1% of Total Capital Investment	$119,458	$216,730
Insurance	1% of Total Capital Investment	$119,458	$216,730
Overhead	60% of total labor and material costs	$22,623	$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$962,672	$1,746,546
Total Indirect Annual Costs		**$1,463,128**	**$2,636,088**
TOTAL ANNUAL COST		**$1,500,833**	**$2,673,793**

Life	Interest %
30	7%

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] Electricity cost form U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

[3] Water cost from Maui County (https://www.mauicounty.gov/216/Water-Charges) lowest general rate.

For ESP Plate Area (Section 3.2.1):

p 1 - (Control Efficiency %)
5.080 ft^2/kacfm 1 (s/m)
w_e effective migration velocity (m/s), assume w_e 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficiency or fuel oil)
Q system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

Original Submitted Spreadsheet

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Hill 5	Hill 6
Average High Exhaust Flow Rate (m^3/s)[1]		26.5	48.1
Average High Exhaust Flow Rate (ACFM)[1]		56,135	101,845
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)	ESCA -ln(p)/w_e × 5.080 × Q	2,091	3,794
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	$25.5/acfm	$1,431,451	$2,597,038
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$644,153	$1,168,667
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$2,075 604	$3,765,705
Instrumentation	0.10 A	$207,560	$376,570
Sales taxes	0.03 A	$62,268	$112,971
Freight	0.05 A	$103,780	$188,285
Purchased Equipment cost, PEC	**B = 1.18 A**	**$2,449,212**	**$4,443,531**
Direct Installation Costs			
Foundation & supports	0.04 B	$97,968	$177,741
Handling & erection	0.50 B	$1,224 606	$2,221,766
Electrical	0.08 B	$195,937	$355,483
Piping	0.01 B	$24,492	$44,435
Insulation for ductwork	0.02B	$48,984	$88,871
Painting	0.02B	$48,984	$88,871
Direct Installation Costs, DIC	**0.67 B**	**$1,640,972**	**$2,977,166**
Total Direct Costs, TDC	**PEC + DIC**	**$4,090,185**	**$7,420,697**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$489,842	$888,706
Construction & field expenses	0.20B	$489,842	$888,706
Contractor fees	0.10B	$244,921	$444,353
Start-up	0.01B	$24,492	$44,435
Performance test	0.01B	$24,492	$44,435
Model study	0.02B	$48,984	$88,871
Contingencies	0.03B	$73,476	$133,306
Total Indirect Costs, IC	**0.57B**	**$1,396,051**	**$2,532,813**
Cost Index[5]			
a. 2019	607.5		
b. 1999	390.6		
Capital recovery factor (CRF)	CRF [I x (1+i)^a]/[(1+i)^a - 1], where I interest rate, a equipment life a. Equipment CRF, 20-yr life, 3.25% interest	0.07	0.07
Total Capital Investment (2019 Dollars)	**(TDC + IC) * (Retrofit factor of 1.4)*(CI_{2019}/CI_{1999}) (Retrofit factor based on average provided for ESP on Page 3-41).**	**$11,945,836**	**$21,672,966**
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	2hr/shift*2shifts/day*365 days/yr * $20/hr	$29,200	$29,200
Supervisor	15% of operator	$4,380	$4,380
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 $4125	$4,125	$4,125
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		**$37,705**	**$37,705**
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$238,917	$433,459
Property tax	1% of Total Capital Investment	$119,458	$216,730
Insurance	1% of Total Capital Investment	$119,458	$216,730
Overhead	60% of total labor and material costs	$22,623	$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$821,621	$1,490,642
Total Indirect Annual Costs		**$1,322,078**	**$2,380,184**
TOTAL ANNUAL COST		**$1,359,783**	**$2,417,889**

Life	Interest %
20	3%

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

[1] Exhaust parameters from Cover Source Permit Application.

[2] Electricity cost form U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

[3] Water cost from Maui County (https://www.mauicounty.gov/216/Water-Charges) lowest general rate.

For ESP Plate Area (Section 3.2.1):

p 1 - (Control Efficiency %)

5.080 ft^2/kacfm 1 (s/m)

w_e effective migration velocity (m/s), assume w_e 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficiency or fuel oil)

Q system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

DOH-CAB Changed Spreadsheet

Appendix Table D-1. Residual High Sulfur Fuel Oil Cost

Date	Residual High Sulfur Fuel Oil [A] ($/BBL)	($/gal)
Jan-18	$57.52	$1.37
Feb-18	$63.81	$1.52
Mar-18	$68.78	$1.64
Apr-18	$61.32	$1.46
May-18	$63.74	$1.52
Jun-18	$69.26	$1.65
Jul-18	$75.84	$1.81
Aug-18	$75.73	$1.80
Sep-18	$76.56	$1.82
Oct-18	$76.16	$1.81
Nov-18	$76.50	$1.82
Dec-18	$85.79	$2.04
Jan-19	$74.99	$1.79
Feb-19	$62.02	$1.48
Mar-19	$62.73	$1.49
Apr-20	$71.38	$1.70
May-19	$75.30	$1.79
Jun-19	$72.39	$1.72
Jul-19	$70.54	$1.68
Aug-19	$62.92	$1.50
Sep-19	$62.28	$1.48
Oct-19	$59.26	$1.41
Nov-19	$59.61	$1.42
Dec-19	$58.81	$1.40
2018-19 Annual Average	**$68.47**	**$1.63**

[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/hawaii-island-energy-cost-filings)

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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.

Appendix Table D-3. Diesel (0.4% Maximum Sulfur) Import Cost

Description	Value	Units
Platts 2018 Price [A]	85.12	$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	86.40	$/BBL
Freight [B]	5.51	$/BBL
Terminalling Fee [B]	2.00	$/BBL
Total ULSD Import Cost [C]	**93.91**	**$/BBL**
	2.24	**$/Gal**

[A] S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 0.25% S which is comparable to the current diesel supply. (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.

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U S. EPA's "Technology Transfer Network" website at: http://www3 epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

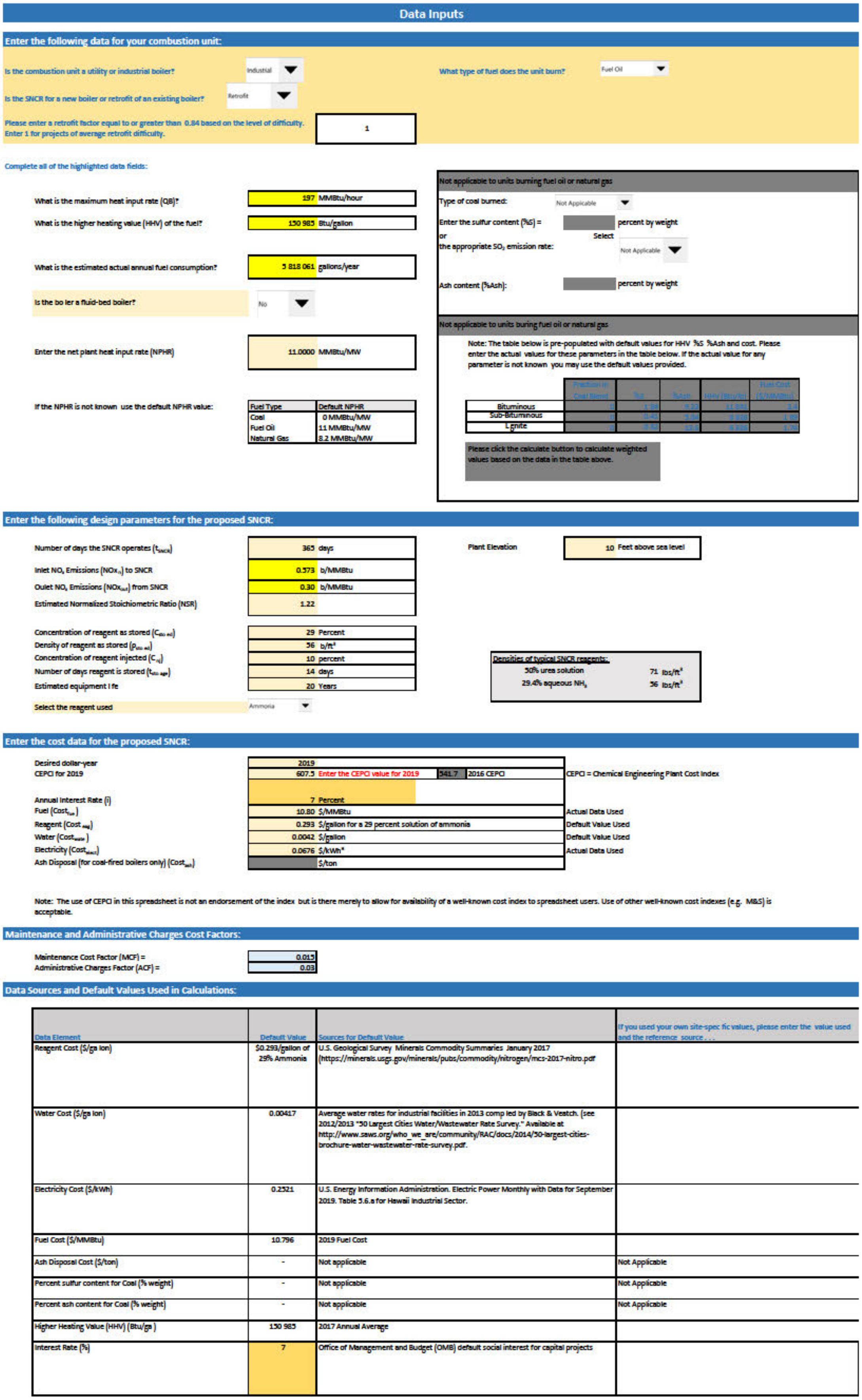
Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.



Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Industrial
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
What type of fuel does the unit burn?	Fuel Oil

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	197	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	150 985	Btu/gallon
What is the estimated actual annual fuel consumption?	5 818 061	gallons/year
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	11.0000	MMBtu/MW

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

Fuel Type	Default NPHR
Coal	0 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 the appropriate SO_3 emission rate:	Select 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.

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	0.573	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.30	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 ($Cost_{fuel}$)	10.80	$/MMBtu	Actual Data Used
Reagent ($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}$)	0.0676	$/kWh*	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($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.

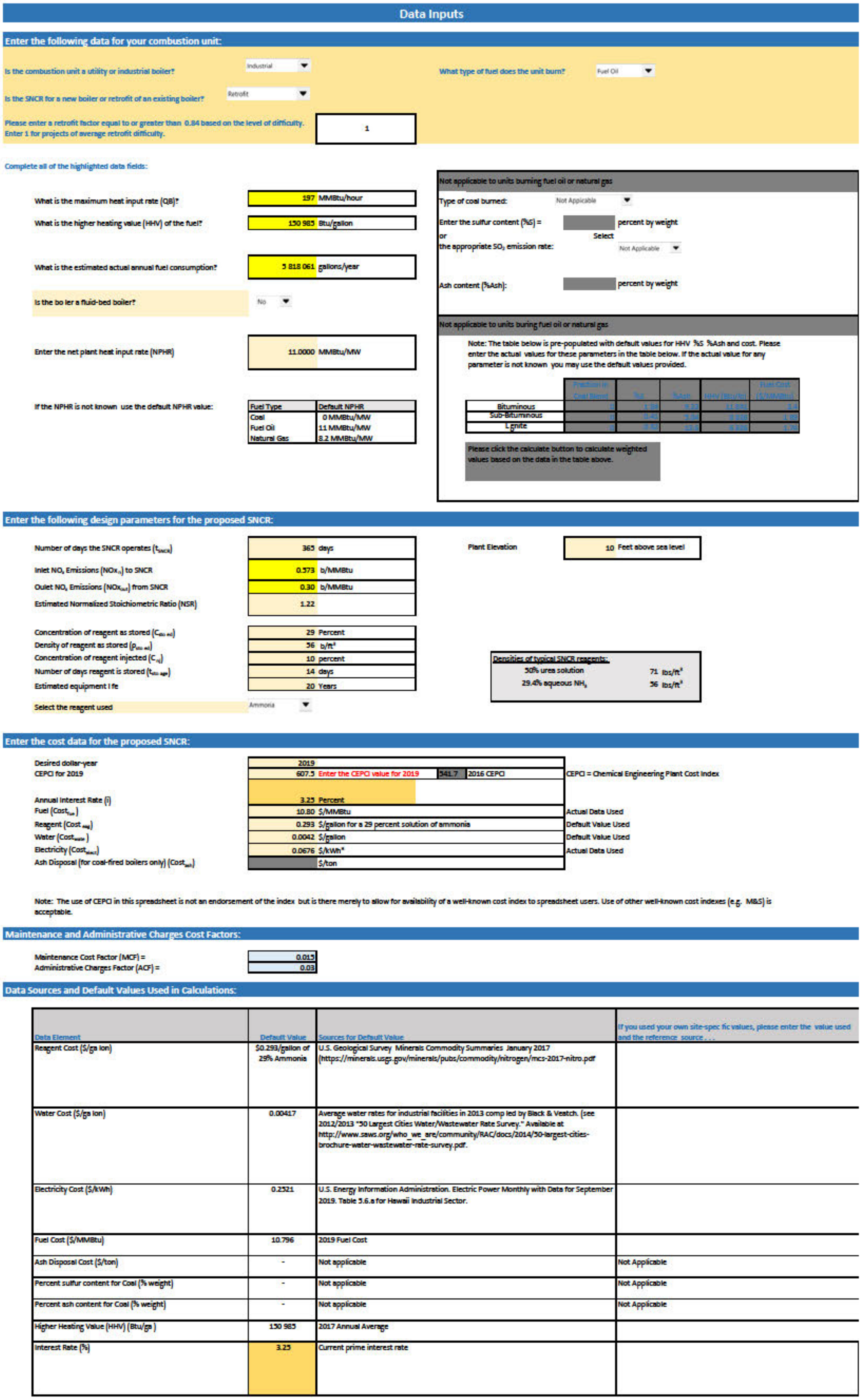
Maintenance and Administrative Charges Cost Factors:

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

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)	10.796	2019 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/gal)	150 985	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Original Submitted Spreadsheet



Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Industrial ▼	What type of fuel does the unit burn?	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 maximum heat input rate (QB)?	197	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	150 985	Btu/gallon
What is the estimated actual annual fuel consumption?	5 818 061	gallons/year
Is the boiler a fluid-bed boiler?	No ▼	
Enter the net plant heat input rate (NPHR)	11.0000	MMBtu/MW

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

Fuel Type	Default NPHR
Coal	0 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 the appropriate SO_2 emission rate:	Select 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.

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	0.573	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.30	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/ft³
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

<u>Densities of typical SNCR reagents:</u>

50% urea solution	71 lbs/ft³
29.4% aqueous NH_3	56 lbs/ft³

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 ($Cost_{fuel}$)	10.80	$/MMBtu	Actual Data Used
Reagent ($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}$)	0.0676	$/kWh*	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($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

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)	10.796	2019 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/gal)	150 985	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

DOH-CAB Changed Spreadsheet

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	197	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	11,429,730	gallons/year	
Actual Annual fuel consumption (Mactual) =		5,818,061	gallons/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.10		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.51	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4459	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	48	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	53.78	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	119.91	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.

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)	51	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	176	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	23.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	7,900	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 =	5.9	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	40	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.41	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

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	197	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	11,429,730	gallons/year	
Actual Annual fuel consumption (Mactual) =		5,818,061	gallons/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.10		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.51	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4459	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	48	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	53.78	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	119.91	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.

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)	51	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	176	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	23.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	7,900	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 =	5.9	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	40	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.41	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

DOH-CAB Changed Spreadsheet

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 ($SNCR_{cost}$) =	$576,475	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$998,520	in 2019 dollars
Total Capital Investment (TCI) =	$2 047 494	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 ($SNCR_{cost}$) =	$576,475	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}) =	$998,520	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$83,782	in 2019 dollars
Indirect Annual Costs (IDAC) =	$194 205	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$277,987	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 =	$30,712	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$30,676	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,774	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$744	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$19,876	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0	in 2019 dollars
Direct Annual Cost =		$83,782	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$921	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$193,283	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$194,205	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$277,987	per year in 2019 dollars
NOx Removed =	120	tons/year
Cost Effectiveness =	$2,318	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

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 ($SNCR_{cost}$) =	$576,475	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$998,520	in 2019 dollars
Total Capital Investment (TCI) =	$2 047 494	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 ($SNCR_{cost}$) =	$576,475	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}) =	$998,520	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$83,782	in 2019 dollars
Indirect Annual Costs (IDAC) =	$141 789	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$225,571	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 =	$30,712	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$30,676	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,774	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$744	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$19,876	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0	in 2019 dollars
Direct Annual Cost =		$83,782	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

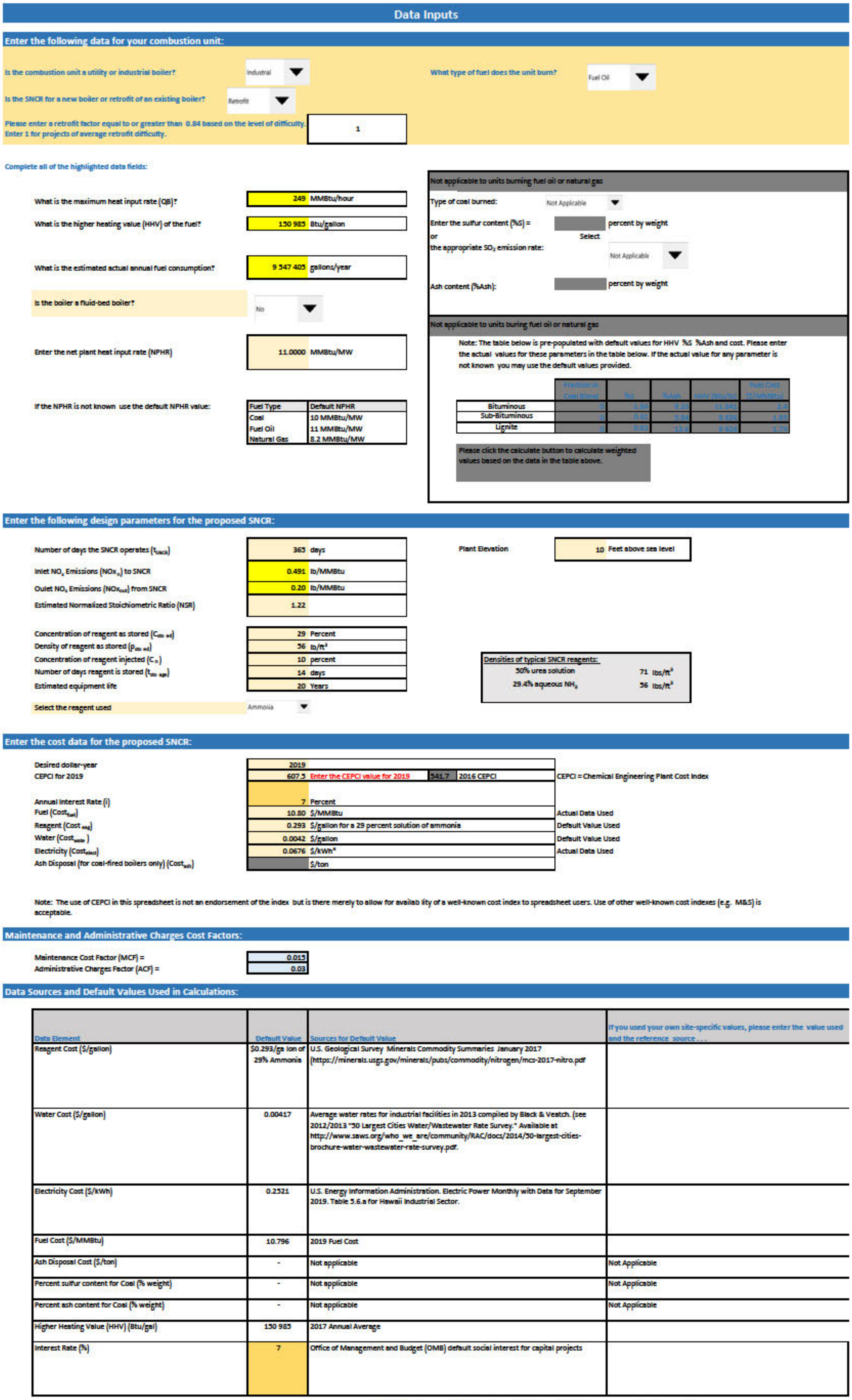
Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$921	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$140,868	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$141,789	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$225,571	per year in 2019 dollars
NOx Removed =	120	tons/year
Cost Effectiveness =	$1,881	per ton of NOx removed in 2019 dollars

DOH-CAB Changed Spreadsheet



Data Inputs

Enter the following data for your combustion unit:

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

What type of fuel does the unit burn? 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 maximum heat input rate (QB)?	249	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	150 985	Btu/gallon
What is the estimated actual annual fuel consumption?	9 547 405	gallons/year
Is the boiler a fluid-bed boiler?	No ▼	
Enter the net plant heat input rate (NPHR)	11.0000	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

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.

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	0.491	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.20	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/ft³
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/ft³
29.4% aqueous NH_3	56 lbs/ft³

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 ($Cost_{fuel}$)	10.80	$/MMBtu	Actual Data Used
Reagent ($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}$)	0.0676	$/kWh*	Actual Data Used
Ash Disposal (for coal-fired boilers only) ($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 availab lity of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g. M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.015

Administrative Charges Factor (ACF) = 0.03

Data Sources 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)	$0.293/ga lon of 29% Ammonia	U.S. Geological Survey Minerals Commodity Summaries January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/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)	10.796	2019 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/gal)	150 985	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

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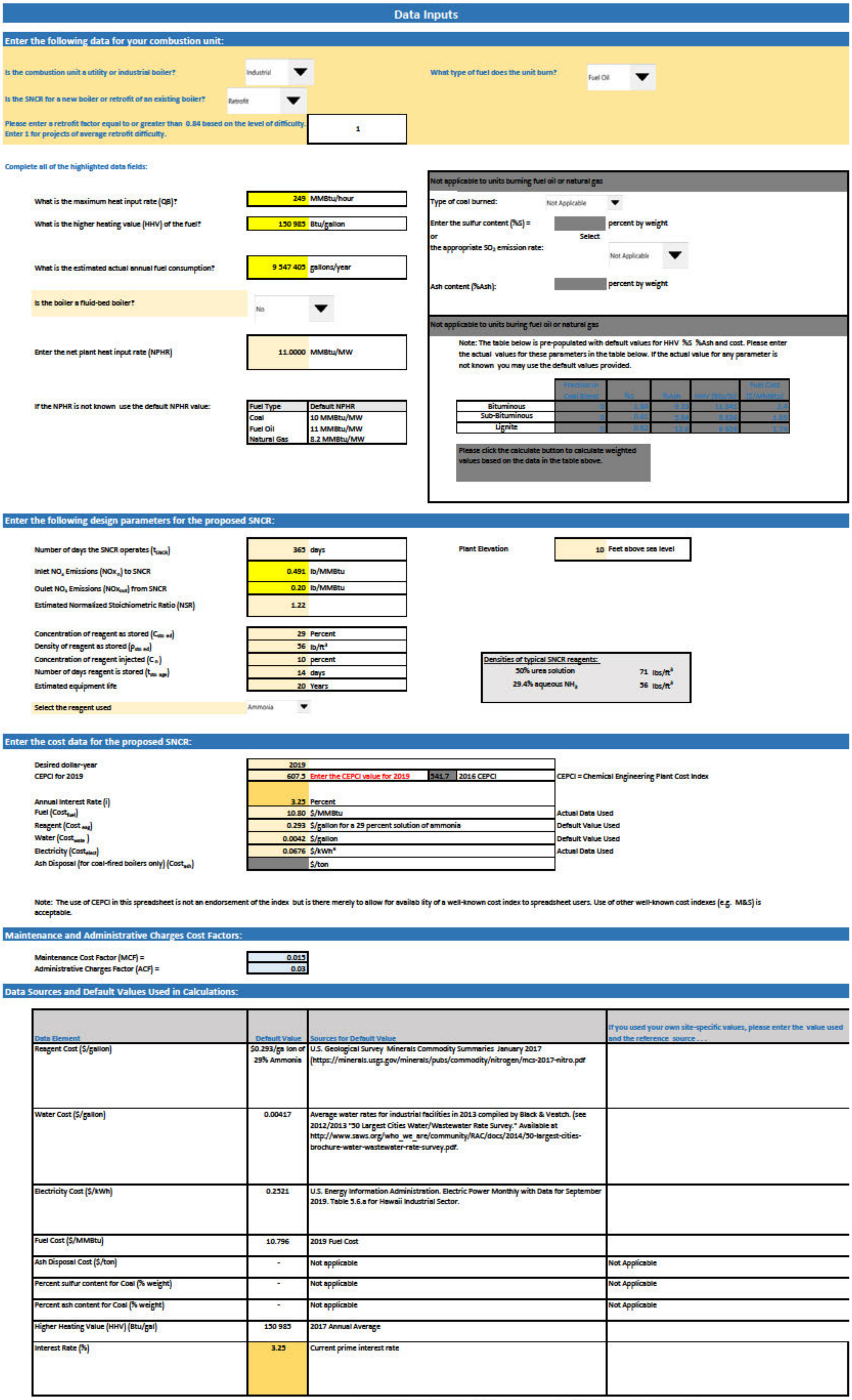

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? 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 maximum heat input rate (QB)? 249 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 150 985 Btu/gallon

What is the estimated actual annual fuel consumption? 9 547 405 gallons/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.0000 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

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.

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 0.491 lb/MMBtu

Oulet NO_x Emissions (NOx_{out}) from SNCR 0.20 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/ft³

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/ft³
29.4% aqueous NH_3	56 lbs/ft³

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 ($Cost_{fuel}$) 10.80 $/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 ($Cost_{elect}$) 0.0676 $/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 availab lity of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g. M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.015

Administrative Charges Factor (ACF) = 0.03

Data Sources 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)	$0.293/ga lon of 29% Ammonia	U.S. Geological Survey Minerals Commodity Summaries January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/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)	10.796	2019 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/gal)	150 985	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

DOH-CAB Changed Spreadsheet

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	249	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	14,446,714	gallons/year	
Actual Annual fuel consumption (Mactual) =		9,547,405	gallons/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.10		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.66	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5789	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	59	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	72.46	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	209.74	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.

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)	55	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	190	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	25.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	8,600	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 =	6.4	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	43	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.45	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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SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	249	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	14,446,714	gallons/year	
Actual Annual fuel consumption (Mactual) =		9,547,405	gallons/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.10		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.66	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5789	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	59	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	72.46	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	209.74	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.

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)	55	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	190	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	25.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	8,600	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 =	6.4	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	43	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.45	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

DOH-CAB Changed Spreadsheet

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 ($SNCR_{cost}$) =	$636,075	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,118,058	in 2019 dollars
Total Capital Investment (TCI) =	$2 280 373	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 ($SNCR_{cost}$) =	$636,075	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}) =	$1,118,058	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$108,830	in 2019 dollars
Indirect Annual Costs (IDAC) =	$216 293	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$325,124	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 =	$34,206	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$43,136	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$2,494	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$1,046	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$27,949	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$0	in 2019 dollars
Direct Annual Cost =		$108,830	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,026	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$215,267	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$216,293	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$325,124	per year in 2019 dollars
NOx Removed =	210	tons/year
Cost Effectiveness =	$1,550	per ton of NOx removed in 2019 dollars

Original Submitted Spreadsheet

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$636,075	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,118,058	in 2019 dollars
Total Capital Investment (TCI) =	$2 280 373	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$636,075	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,118,058	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$108,830	in 2019 dollars
Indirect Annual Costs (IDAC) =	$157 916	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$266,746	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 =	$34,206	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$43,136	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$2,494	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,046	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$27,949	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$108,830	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,026	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$156,890	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$157,916	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$266,746	in 2019 dollars
NOx Removed =	210	tons/year
Cost Effectiveness =	$1,272	per ton of NOx removed in 2019 dollars

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