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AES
we are the energy

July 30, 2019

Clean Air Branch
Hawaii Department of Health
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Subject: AES Hawaii Covered Source Permit (CSP) No. 0087-02-C
Greenhouse Gas Emission Reduction Plan Re-Submittal

Dear Ms. Rossio,

AES Hawaii, LLC is re-submitting the attached Greenhouse Gas Emission Reduction Plan (ERP) required by (HAR) §11-60.1-204. The initial submittal was made on December 1, 2016 and a revision was provided in February 28, 2018 to reflect a partnership arrangement in accordance with the ACT 234 implementing regulations. The plan was re-submitted on October 30, 2018 addressing comments via email from Mike Madsen of the Clean Air Branch on October 12, 2018. The following updates were made to the current ERP submittal:

1. On February 13, 2019, AES Hawaii, Inc. completed its statutory conversion from a Delaware corporation to a Delaware limited liability company and is now known was AES Hawaii, LLC. The ERP reflects the updated name reference.

2. On July 26, 2019, Hawaii Electric Company (HECO) resubmitted their ERP with proposed 2019 GHG cap adjustment to the Hawaii Department of Health (DOH). Tables A-1 and A-2 are updated in Appendix C of AES Hawaii's ERP to reflect this change.

This ERP submission supersedes all previous ERP submissions. If you have any questions, please call Priya Kumar at 682-3409 or e-mail at priya.kumar@aes.com.

Sincerely,

Steven Barnoski
Plant Manager
AES Hawaii, LLC

enclosure

Certification Statement:
Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Steven Barnoski, Plant Manager

Date: 7-30-19

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AES HAWAII, LLC

GREENHOUSE GAS EMISSION REDUCTION PLAN

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GREENHOUSE GAS EMISSION REDUCTION PLAN

JULY 30, 2019

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EXECUTIVE SUMMARY

This Greenhouse Gas (GHG) Emissions Reduction Plan (ERP) has been prepared in accordance with Hawaii Administrative Rules (HAR) §11-60.1 Subchapter 11 (Subchapter 11), which implement Act 234, 2007 Hawaii Session Laws, Relating to GHG Emissions, enacted in Sections 342B-71-73, Hawaii Revised Statutes (HRS).

In general, Subchapter 11 requires statewide reduction of GHG emissions to 1990 levels by 2020, and establishes a minimum reduction of 16% for affected facilities from the baseline year of 2010 unless it is determined that 16% reduction is unattainable. The following steps are to be included in an affected facility's GHG ERP:

- Establish facility-wide baseline GHG emissions (HAR §11-60.1-204(d)(1))
- Determine if 2020 facility-wide GHG emissions cap based on 16% reduction from baseline levels is attainable (HAR §11-60.1-204(d)(2))
- Identify all available control measures (HAR §11-60.1-204(d)(3))
- Eliminate technically infeasible options (HAR §11-60.1-204(d)(4))
- Control effectiveness and cost evaluation (HAR §11-60.1-204(d)(5))
- Proposed control strategy (HAR §11-60.1-204(d)(6))

AES HAWAII, LLC (AES Hawaii), located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu is a coal-fired cogeneration plant that utilizes "clean coal" technology to generate steam and electricity. The facility is designed to sell sufficient quantities of process steam to be a "Qualifying Facility" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). AES Hawaii is the single largest electric power generator on Oahu and provides 20% of the island's electrical energy demand. AES sells electricity to Hawaii Electric Company (HECO) under a 30-year Power Purchase Agreement (PPA) that expires in October 2022. The following stationary sources directly emit GHG emissions from the facility and have been included in the GHG control evaluation.

- Boilers A and B
- Limestone Dryers

On December 1, 2016, AES Hawaii submitted to the Hawaii Department of Health (DOH) an ERP prepared by Sargent & Lundy, L.L.C. (S&L) for the AES Hawaii facility, included as Appendix A. The calculations in the 2016 ERP submittal have been updated in this submittal to the same calculation methodology used by AES Hawaii for the 2010 baseline calculation. This submittal version supersedes all previous submittals of the ERP.

In completing the ERP, S&L concluded that the required GHG emissions cap for AES Hawaii was unattainable as none of the available and technically feasible GHG control options for AES Hawaii were considered to be cost effective. Hawaii Administrative Rules, §11-60.1-204(d)(6), allow affected sources to propose combining their facility-wide GHG emissions caps to leverage emission reductions among partnering facilities. In this ERP, AES Hawaii proposes to partner with HECO for the purpose of rule compliance as well as providing additional operational flexibility. HECO has stated its intent to partner with certain other independent power producers and is willing to include AES Hawaii in such partnering.

AES Hawaii determined that calendar year 2010 was appropriate to establish the facility-wide baseline GHG emissions. The proposed 2010 baseline emissions for AES Hawaii are based on 40 CFR Part 98 calculation methodology and detailed calculations are provided in Appendix B. Details regarding the Total Partnership Baseline Emissions are included in Appendix C.

Table ES-1: Total Partnership Baseline Emissions, Including AES Hawaii

Company	Total CO_2e Short tons/yr
AES Hawaii	1,681,605
HECO Total	5,401,629
Other Partnering Companies	1,277,788
Total Partnership	8,361,022

In the 2016 ERP, S&L evaluated GHG emissions reductions options available to AES Hawaii for: (1) achieving 16% GHG emissions reduction from the baseline, or (2) proposing an alternative emissions cap resulting in the maximum achievable GHG emissions reductions. In addition, S&L followed EPA's "top-down" approach for determining best available control technology (BACT) and EPA guidelines for conducting a GHG BACT analysis.

The AES Hawaii GHG emissions control assessment identified three GHG control option categories that were considered technically feasible: (1) heat rate improvements, (2) fuel oil co-firing, and (3) biomass co-firing. Table ES-2 identifies technically feasible GHG control options considered in the 2016 ERP in descending order of control effectiveness.

Table ES-2: Technically Feasible GHG Control Options by Effectiveness

GHG Control Option	GHG Control Effectiveness	Expected GHG Emission Rate		Expected Emission Reduction
	% removal	tons CO_2e/yr	lbs CO_2e/kWh-g	tons CO_2e/yr
Pelletized Biomass Co-firing @ 25% Heat Input	16.0%	**1,412,549**	1.708	269,056
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,469,480**	1.777	212,125
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,575,411**	1.905	106,194
Heat Rate Improvement Combination (All Options)	3.1%	**1,629,055**	1.970	52,550
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,646,361**	1.991	35,245
Turbine Upgrade	1.25%	**1,660,585**	2.008	21,020
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,664,789**	2.013	16,816
Air Heater Temperature Reduction	0.75%	**1,668,993**	2.018	12,612
Sootblower Improvements	0.70%	**1,669,834**	2.019	11,771
DCS Upgrade	0.50%	**1,673,197**	2.023	8,408
VFD Motors	0.30%	**1,676,560**	2.028	5,045
Baseline Emissions	--	**1,681,605**	2.034	--

The technically feasible GHG control options were evaluated for economic, environmental and energy impacts. The results of the economic, environmental, and energy impact analysis are provided in Table ES-3.

Table ES-3. Summary of Economic, Environmental, and Energy Impact Analysis for GHG Emissions Control Options

GHG Control Option	Average Annual Cost Effectiveness $/ton CO_2e removed	Environmental Impacts	Energy Impacts
VFD Motors	$288	N/A	N/A
DCS Upgrade	$222	N/A	N/A
Sootblower Improvements	$51	N/A	N/A
Air Heater Temperature Reduction	$1,792	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$122	N/A	N/A
Turbine Upgrade	$397	N/A	N/A
Fuel Oil Co-firing @ 10% Heat Input	$510	Increased hazardous air pollutant (HAP) emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$579	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$508	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$175	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$126	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate

The economic evaluations performed for the technically feasible control options indicate that, based on expected emissions reductions and estimated control costs, the average annual cost effectiveness of the GHG control systems range from $51 per ton (sootblowing improvements) to $1,792 per ton (air heater temperature reduction) GHG removed. For the purposes of the evaluation, it was concluded that GHG control options having cost effectiveness values greater than $23 per ton GHG removed were not cost effective. Therefore, based on a cost effectiveness threshold of $23 per ton GHG removed, none of the available and technically feasible GHG control options for AES Hawaii are considered to be cost-effective. The detailed evaluation is included in the 2016 ERP.

AES Hawaii is proposing as its control strategy, to partner with HECO and the other partnering facilities identified by HECO, combining the emissions caps to leverage the emissions reductions among the partnering facilities. HECO has contracted to purchase power from AES Hawaii and other Independent Power Producers in order to meet its obligation to meet the electric power demands of its customers at all times. Also, in the event that there is an energy shortfall from unplanned outages or other issues, AES Hawaii may be required to generate additional electricity. Therefore, the adjusted cap for AES Hawaii includes the possibility that AES Hawaii may be required to generate more electricity than had been generated in 2010. The AES Hawaii adjusted facility-wide GHG emissions cap and Total Partnership Cap is identified in Table ES-4. The table also includes AES Hawaii's compliance demonstration methodology. The Total Partnership Cap represents a 16% reduction in GHG emissions as compared to the Total Partnership Baseline. The GHG Reduction Partnership details are included in Appendix C.

AES Hawaii plans to meet its adjusted facility-wide GHG emissions cap by continuing to implement a comprehensive inspection and preventative maintenance program that addresses boiler operation, maintenance and efficiency.

Table ES-4. Proposed 2020 GHG Emissions Caps

Pollutant	Total Partnership Cap	AES Hawaii Adjusted Facility-Wide Emissions Cap	AES Hawaii Compliance Demonstration Methodology
CO_2e	7,208,661 short tons/yr	1,691,605 short tons/yr	CO_2 CEMS (Boilers A and B) GHG emissions calculations using annual fuel and limestone consumption rates, and representative emissions factors

1. FACILITY DESCRIPTION

AES Hawaii, located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu, commenced commercial operation in 1992. The facility is a coal-fired cogeneration plant that utilizes "clean coal" technology to generate steam and electricity. The facility is designed to sell sufficient quantities of steam to be a "Qualifying Facility" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). AES Hawaii is the single largest electric power generator on Oahu and provides 20% of the island's electrical energy demand. AES sells to Hawaii Electric Company (HECO) under a 30-year Power Purchase Agreement (PPA) that expires in October 2022. Approximately 97% of the plant's total capacity is committed to HECO under the PPA. The facility operates under Covered Source Permit (CSP) No. 0087-02-C, and has one (1) electric generating unit (EGU) that is comprised of two boilers, Boilers A and B.

Boilers A and B are each Ahlstrom Pyropower Corp., circulating fluidized bed (CFB) steam boilers with a total maximum design heat input of 2,150 MMBtu/hr. Power output from the facility is currently limited to a maximum 180 MW-net (nominal) in accordance with facility's current PPA. In addition to generating electricity, a small percentage of total steam produced is sold to a nearby industrial facility. Each boiler is equipped with a limestone injection system for sulfur dioxide (SO_2) control, selective non-catalytic reduction (SNCR) for nitrogen oxide (NO_X) control, and fabric filter baghouse for control of particulate matter (PM) emissions. Boilers A and B are currently permitted to fire coal as the primary fuel, and limited amounts of wood fuel, tire derived fuel (TDF), spent activated carbon, and specification oil. Fuel oil is the startup fuel for Boilers A and B.

Emission sources installed at the facility include:

- Boilers A and B (coal as primary fuel with limited amounts alternative fuels)
- Coal Processing Equipment
- Limestone Processing Equipment
- One (1) five-cell (5-cell) cooling tower
- Ash handling equipment
- One (1) 60,000 gallon No. 2 fuel oil storage tank

The following stationary sources directly emit GHG emissions from the facility and are included in the GHG control evaluation.

- Boilers A and B
- Limestone Dryers

2. FACILITY-WIDE TOTAL BASELINE GHG EMISSIONS

The first step in developing the GHG ERP is to establish facility-wide baseline GHG emissions based on calendar year 2010 emissions. If calendar year 2010 is deemed unrepresentative of normal operation, an alternative annual baseline emission rate meeting requirements of HAR §11-60.1-204(d)(1)(A) may be proposed.

In the December 2016 ERP, S&L evaluated AES Hawaii's facility-wide operations for the period 2005 to 2015 to determine if calendar year 2010 was representative of normal AES Hawaii operations. Based on review of annual fuel consumption rates, actual fuels consumed, boiler heat inputs, boiler heat rates, power generation, and capacity factors, it was determined that calendar year 2010 was representative of normal facility-wide operation. Therefore, facility total baseline annual GHG emissions for AES Hawaii have been based on calendar year 2010 emissions.

In accordance with HAR §11-60.1-115, baseline annual CO_2e emission rates shall be determined based on (1) stack test reports, continuous emissions monitoring data, or any other certified record, or (2) emission factors used in complying with 40 CFR Part 98, Mandatory GHG Reporting. Prior to calendar year 2011, CO_2 continuous emissions monitoring systems (CEMS) were not installed on the AES Hawaii Boilers A and B; therefore, baseline annual emissions from Boilers A and B have been based on calculations per 40 CFR Part 98 that use 2010 annual fuel data and consumption rates. In the 2016 ERP, the CO2 emissions from the Boilers A and B were calculated using the 40 CFR Part 98, Table C-1[1]. Per §98.33 (b)(3), the accepted calculation methodology for AES Hawaii's boilers is Equation C-3 in section §98.33 (a)(3). Equation C-3 uses the annual average carbon content of the solid fuel, and therefore for this ERP submittal, AES Hawaii recalculated the boiler CO2 emissions for the 2010 baseline using Equation C-3. This resulted in a slightly higher baseline emissions value. Calendar year 2010 baseline emissions are calculated as follows:

Facility-Wide Baseline Emissions (tpy CO_2e) = Facility-Total Baseline GHG Emissions (tpy CO_2e) – Facility Baseline Biogenic CO_2 Emissions (tpy CO_2)

[1] 40 CFR Part 98, Table C-1 Default CO2 Emission Factors and High Heat Values for Various Types of Fuel

Table 2-1 provides a summary of the AES Hawaii 2010 facility-wide baseline annual emissions. The detailed emissions are included in Appendix B. In addition, Table 2-2 provides a summary of the Total Partnership Baseline Emissions.

Table 2-1: AES Hawaii 2010 Facility-wide Baseline Emissions (short tons per year)

	CO_2		N_2O		CH_4		Total CO_2e(1)
	Non-Biogenic, tons/yr	Biogenic, tons/yr	tons/yr, as N_2O	tons/yr, as CO_2e(1)	tons/yr, as CH_4	tons/yr, as CO_2e(1)	Short tons/yr
Boilers A and B (total)	1,668,138	0	28	8,627	191	4,015	1,680,781
Limestone Dryers	822	0	0	2	0	1	824
Facility-Wide Total	1,668,960	0	28	8,629	191	4,016	1,681,605

Note 1. CO_2e emissions calculated based on 2010 GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, N_2O = 310, CH_4 = 21).

Table 2-2: Total Partnership Baseline Emissions

Company	Total CO_2e Short tons/yr
AES Hawaii	1,681,605
HECO Total	5,401,629
Other Partnering Companies	1,277,788
Total Partnership	8,361,022

3. 2020 FACILITY-WIDE GHG EMISSIONS CAP

This section provides a summary of the 2016 evaluation completed by S&L of GHG emission reduction options available to AES Hawaii that determined a 16% reduction in GHG emissions from the 2010 baseline was not attainable, and a description of the current proposed control strategy for GHG emissions, which employs a partnership arrangement with HECO.

3.1 2016 PROPOSED CONTROL STRATEGY

In the 2016 ERP, S&L followed EPA's "top-down" approach for determining best available control technology (BACT)[2] and EPA guidelines for conducting a GHG BACT[3] analysis, which is consistent with the requirements of Subchapter 11. The "top-down" approach utilized in the evaluation included the following steps:

Step 1: Identify Potentially Feasible GHG Control Options
Step 2: Evaluate the Technical Feasibility of Potential GHG Control Options
Step 3: Rank the Technically Feasible GHG Control Options by Effectiveness
Step 4: Evaluate the Technically Feasible GHG Control Options for:

- Economic Impacts
- Environmental Impacts
- Energy Impacts

Step 5: Proposed Control Strategy for GHG Emissions

The 2016 S&L evaluation of GHG control options for AES Hawaii identified certain heat rate improvements and co-firing options that are technically feasible in terms of GHG emissions reductions. An economic evaluation performed for each heat rate improvement option indicated that, based on expected emissions reductions and estimated control costs, the average annual cost effectiveness of the GHG control systems ranged from $51 per ton (sootblowing improvements) to $1,792 per ton (air heater temperature reduction) GHG removed. Fuel oil and biomass co-firing were possibly technically feasible GHG reduction options as well, however, the average cost effectiveness of these options ranged from $126 per ton to $510 per ton.

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[2] EPA Office of Air Quality Planning and Standards, *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting*, Draft, October 1990.

[3] EPA Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011.

3.1.1 Cost Effectiveness Threshold

EPA and DOH have not defined a cost threshold at which GHG control options for existing power plants are considered "cost effective." However, based on the Hyperion Energy BACT determination completed in 2009 and the market price of CO_2 allowances in existing regional trading programs, it was concluded that GHG control options with cost effectiveness values less than $11.50 per ton GHG removed could be considered cost effective.

In addition to reviewing current market prices, cost estimates prepared by EPA for the Clean Power Plan (CPP) were also reviewed by S&L. For Building Block 1, EPA concluded that the assumed CO_2 reductions associated with energy efficiency improvements at existing coal-fired facilities are reasonable at a cost of $23 per ton.[4]

Based on the range of costs identified for AES Hawaii GHG control options, and an assumed cost effectiveness threshold of $23 per ton GHG removed, all of the technically feasible GHG emissions improvements identified for AES Hawaii were considered cost prohibitive. AES Hawaii concluded that the required 16% emissions reduction cap was not attainable.

3.2 CURRENT PROPOSED CONTROL STRATEGY.

AES Hawaii is proposing as its control strategy, to partner with HECO and the other partnering facilities identified by HECO, combining the emissions caps to leverage the emissions reductions among the partnering facilities. HECO has contracted to purchase power from AES Hawaii and other Independent Power Producers in order to meet its obligation to meet the electric power demands of its customers at all times. Also, in the event that there is an energy shortfall from unplanned outages or other issues, AES Hawaii may be required to generate additional electricity. Therefore, the adjusted cap for AES Hawaii includes the possibility that AES Hawaii may be required to generate more electricity than had been generated in 2010. The AES Hawaii adjusted facility-wide GHG emissions cap and Total Partnership Cap is identified in Table 3-1. The table also includes AES Hawaii's compliance demonstration methodology. The Total Partnership Cap represents a 16% reduction in GHG emissions as compared to the Total Partnership Baseline.

[4] 80 FR 64749, col. 1.

AES Hawaii will achieve the proposed control strategy by continuing to implement the facility's existing comprehensive inspection and preventive maintenance program designed to address boiler operation, maintenance, and efficiency.

It is anticipated that each of the participating facilities included within the Total Partnership Cap shall be considered in compliance with the GHG Rule regardless of whether such facility's emissions have exceeded such facility's specific cap as long as the combined emissions of all facilities included within the Total Partnership Cap do not exceed the limit on total emissions established by the Total Partnership Cap.

Table 3-1: Proposed 2020 GHG Emissions Caps

Pollutant	Total Partnership Cap	AES Hawaii Facility-Wide Emissions Cap	Compliance Demonstration Methodology
CO_2e	7,208,661 short tons/yr	1,691,605 short tons/yr	CO_2 CEMS (Boilers A and B) GHG emissions calculations using annual fuel consumption rates and limestone consumption rates, and representative emissions factors

4. GHG REDUCTION PARTNERSHIP

This section explains Hawaiian Electric Companies' partnership approach to preparing their GHG ERPs.

The power generation facilities operating on each of Hawai'i's islands are highly interdependent. If one or more of them cannot produce their scheduled power output, the other facilities on the island have to generate more power to make up for the shortfall. An unscheduled outage that takes a major generating unit offline for a period of time can significantly shift GHG emissions from one facility to another. Assigning firm GHG emissions caps to individual facilities does not provide sufficient flexibility to accommodate those types of system events that are a natural part of system operation.

For these reasons, the Hawaiian Electric Companies and three independent power producers have elected to make use of the partnering provisions in Act 234 Regulations[5] to create a Partnership involving all eleven of the Hawaiian Electric Companies Affected Sources, the Hamakua Energy owned facility, the AES Hawaii facility, and the Kalaeloa Partners LP (KPLP) facility (collectively the Partnership Facilities). The Partnership has an overall GHG emissions cap that it commits to attain. Individual facilities have site-specific GHG reduction goals that are used to apportion penalties that may be assessed in the event the overall cap is exceeded. The DOH will include the site-specific goals as GHG caps, along with implementing conditions, in each site's Covered Source Permit (CSP). Owing to the operating flexibility that partnering in this manner affords, the Partnership Facilities can commit to an aggregate 16% reduction of GHG emissions from their respective baselines for their facilities. The site-specific and overall reduction targets for the Partnership Facilities are listed in Appendix C

[5] HAR 11-60.1-204(d)(6)(A)

APPENDIX A. EMISSION REDUCTION PLAN BY SARGENT AND LUNDY, DECEMBER 1, 2016, REVISED ON OCTOBER 30, 2018

AES United States

AES HAWAII, INC.

GREENHOUSE GAS EMISSION REDUCTION PLAN

OCTOBER 30, 2018
PROJECT NO. 13467-001

PREPARED BY

Sargent & Lundy LLC

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APPENDIXES

TABLES AND FIGURES

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ABBREVIATIONS AND ACRONYMS

Abbreviation/Acronym	Explanation
AH	air heater
BACT	best available control technology
CAA	Clean Air Act
CAB	Clean Air Branch
CEMS	continuous emissions monitoring system
CFB	circulating fluidized bed
CFR	Code of Federal Regulations
CHP	combined heat and power
CO_2	carbon dioxide
CPP	Clean Power Plan
CSP	Covered Source Permit
DOE	U.S. Department of Energy
DOH	Hawaii Department of Health
DSI	dry sorbent injection
EGU	electric generating unit
EPA	U.S. Environmental Protection Agency
EOR	enhanced oil recovery
ERP	Emission Reduction Plan
ESP	electrostatic precipitator
FD	forced draft
FGD	flue gas desulfurization
GHG	greenhouse gas
HAP	hazardous air pollutant
HAR	Hawaii Administrative Rule
HECO	Hawaiian Electric Company
HP	high pressure
HRI	heat rate improvement
HRS	Hawaii Revised Statutes
ID	induced draft
IP	intermediate pressure
IPCC	International Panel on Climate Change
ISB	integrated sootblower
LAER	lowest achievable emission rate
LP	low pressure
MATS	Mercury and Air Toxics Standards
MEA	monoethanol amine

ABBREVIATIONS AND ACRONYMS

MW	megawatt
NSR	New Source Review
NN	neural network
NREL	National Renewable Energy Laboratory
O&M	operating and maintenance
PA	primary air
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RACT	reasonably available control technology
RBLC	RACT BACT LAER Clearinghouse
RDF	refuse derived fuel
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
TDF	tire derived fuel
T/R	transformer/rectifier
VFD	variable-frequency drive

EXECUTIVE SUMMARY

Sargent & Lundy, L.L.C. (S&L) was retained by AES Hawaii, Inc. (AES Hawaii) to prepare a greenhouse gas (GHG) Emission Reduction Plan (ERP) for the AES Hawaii facility located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu. This GHG ERP has been prepared in accordance with Hawaii Administrative Rules (HAR) §11-60.1 Subchapter 11 (Subchapter 11), which implement Act 234, 2007 Hawaii Session Laws, Relating to Greenhouse Gas Emissions, enacted in Sections 342B-71-73, Hawaii Revised Statutes (HRS).

In general, Subchapter 11 requires statewide reduction of GHG emissions to 1990 levels by 2020, and establishes a minimum reduction of 16% for affected facilities from the baseline year of 2010 unless it is determined that 16% reduction is unattainable. The following steps are to be included in an affected facility's GHG ERP:

- Establish facility-wide baseline GHG emissions (HAR §11-60.1-204(d)(1))
- Determine if 2020 facility-wide GHG emissions cap based on 16% reduction from baseline levels is attainable (HAR §11-60.1-204(d)(2))
- Identify all available control measures (HAR §11-60.1-204(d)(3))
- Eliminate technically infeasible options (HAR §11-60.1-204(d)(4))
- Control effectiveness and cost evaluation (HAR §11-60.1-204(d)(5))
- Proposed control strategy (HAR §11-60.1-204(d)(6))

AES Hawaii is a coal-fired cogeneration plant that utilizes "clean coal" technology to generate steam and electricity. The facility is designed to sell sufficient quantities of process steam to be a "Qualifying Facility" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). AES Hawaii is the single largest electric power generator on Oahu and provides 20% of the island's electrical energy demand. AES sells electricity to Hawaii Electric Company (HECO) under a 30-year Power Purchase Agreement (PPA) that expires in October 2022. The following stationary sources directly emit GHG emissions from the facility and have been included in the GHG control evaluation.

- Boilers A and B
- Limestone Dryers

The first step in developing the GHG ERP for AES Hawaii was to establish facility-wide baseline GHG emissions based on calendar year 2010 emissions. If calendar year 2010 is deemed unrepresentative of normal operation, an alternative annual baseline emission rate may be proposed. S&L evaluated AES Hawaii's facility-wide operations for the period 2005 to present, and determined that calendar year 2010 is representative of normal facility-wide operation. Therefore, facility-wide baseline GHG emissions were based on calendar year 2010 emissions. Baseline annual emissions, which are based on representative emission factors obtained from 40 CFR Part 98 and 2010 annual material consumption rates, are identified in Table ES-1.

Table ES-1: AES Hawaii 2010 Facility-wide Baseline Emissions

	CO_2		N_2O		CH_4		Total CO_2e
	Non-Biogenic, tons/yr	Biogenic, tons/yr	tons/yr, as N_2O	tons/yr, as $CO_2e^{(1)}$	tons/yr, as CH_4	tons/yr, as $CO_2e^{(1)}$	tons/yr
Boilers A and B (total)	1,668,138	0	28	8,627	191	4,015	1,680,781
Limestone Dryers	822	0	0	2	0	1	824
Facility-Wide Total	1,668,960	0	28	8,629	191	4,016	1,681,605

Note 1. CO_2e emissions calculated based on 2010 GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, N_2O = 310, CH_4 = 21).

The next step in developing the ERP was to evaluate GHG emissions reductions options available to AES Hawaii for: (1) achieving 16% GHG emissions reduction from the baseline, or (2) proposing an alternative emissions cap resulting in the maximum achievable GHG emissions reductions. The control reduction evaluation generally follows EPA's "top-down" approach for determining best available control technology (BACT) and EPA guidelines for conducting a GHG BACT analysis, which are consistent with the requirements of Subchapter 11. The "top-down" approach utilized in this evaluation includes the following steps:

Step 1: Identify Potentially Feasible GHG Control Options
Step 2: Evaluate the Technical Feasibility of Potential GHG Control Options
Step 3: Rank the Technically Feasible GHG Control Options by Effectiveness
Step 4: Evaluate the Technically Feasible GHG Control Options for:

- Economic Impacts
- Environmental Impacts
- Energy Impacts

Step 5: Proposed Control Strategy for GHG Emissions

The AES Hawaii GHG emissions control assessment identified three GHG control option categories that are considered technically feasible: (1) heat rate improvements, (2) fuel oil co-firing, and (3) biomass co-firing. Table ES-2 identifies technically feasible GHG control options in descending order of control effectiveness.

Table ES-2: Technically Feasible GHG Control Option by Effectiveness

GHG Control Option	GHG Control Effectiveness % removal	Expected GHG Emission Rate tons CO_2e/yr	 lbs CO_2e/kWh-g	Expected Emission Reduction tons CO_2e/yr
Pelletized Biomass Co-firing @ 25% Heat Input	16.0%	**1,412,549**	1.708	269,056
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,469,480**	1.777	212,125
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,575,411**	1.905	106,194
Heat Rate Improvement Combination (All Options)	3.1%	**1,629,055**	1.970	52,550
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,646,361**	1.991	35,245
Turbine Upgrade	1.25%	**1,660,585**	2.008	21,020
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,664,789**	2.013	16,816
Air Heater Temperature Reduction	0.75%	**1,668,993**	2.018	12,612
Sootblower Improvements	0.70%	**1,669,834**	2.019	11,771
DCS Upgrade	0.50%	**1,673,197**	2.023	8,408
VFD Motors	0.30%	**1,676,560**	2.028	5,045
Baseline Emissions	--	**1,681,605**	2.034	--

The technically feasible GHG control options were evaluated for economic, environmental and energy impacts. The results of the economic, environmental, and energy impact analysis are provided in Table ES-3.

Table ES-3. Summary of Economic, Environmental, and Energy Impact Analysis for GHG Emissions Control Options

GHG Control Option	Average Annual Cost Effectiveness $/ton CO_2e removed	Incremental Annual Cost Effectiveness(1) $/ton CO_2e removed	Environmental Impacts	Energy Impacts
VFD Motors	$288	--	N/A	N/A
DCS Upgrade	$222	$123	N/A	N/A
Sootblower Improvements	$51	--	N/A	N/A
Air Heater Temperature Reduction	$1,792	$26,162	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$122	$288	N/A	N/A
Turbine Upgrade	$397	$1,498	N/A	N/A
Fuel Oil Co-firing @ 10% Heat Input	$510	$677	Increased hazardous air pollutant (HAP) emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$579	$719	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$508	$439	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$175	$42	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$126	$16	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate

Note 1. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual GHG emissions reductions (tpy) between a control option and the next most effective option.

The economic evaluations performed for the technically feasible control options indicate that, based on expected emissions reductions and estimated control costs, the average annual cost effectiveness of the GHG control systems range from $51 per ton (sootblowing improvements) to $1,792 per ton (air heater temperature reduction) GHG removed. For the purpose of this evaluation, it was concluded that GHG control options having cost effectiveness values greater than $23 per ton GHG removed are not cost effective. Therefore, based on a cost effectiveness threshold of $23 per ton GHG removed, none of the available and technically feasible GHG control options for AES Hawaii are considered to be cost-effective.

AES Hawaii is proposing a 2020 facility-wide GHG emissions cap that is based on limiting GHG emissions to 2010 baseline levels. AES Hawaii plans to meet the 2020 facility-wide GHG emissions cap by continuing to implement a comprehensive inspection and preventative maintenance program that addresses boiler operation, maintenance and efficiency. The proposed 2020 facility-wide GHG emissions cap and compliance demonstration method are identified in Table ES-4.

Table ES-4. Proposed 2020 Facility-Wide GHG Emissions Cap

Pollutant	AES Hawaii Facility-Wide Emissions Cap	Method for Controlled GHG Emissions	Compliance Demonstration Methodology
CO_2e	1,681,605 tons/yr	Comprehensive inspection and preventive maintenance program designed to address boiler operation, maintenance, and efficiency	CO_2 CEMS (Boilers A and B) GHG emissions calculations using annual fuel consumption rates and limestone consumption rates, and representative emissions factors

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by AES Hawaii, Inc. (AES Hawaii) to prepare a greenhouse gas (GHG) Emission Reduction Plan (ERP) for the AES Hawaii facility located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu. This GHG ERP has been prepared in accordance with Hawaii Administrative Rules (HAR) §11-60.1 Subchapter 11 (Subchapter 11), which implement Act 234, 2007 Hawaii Session Laws, Relating to Greenhouse Gas Emissions, enacted in Sections 342B-71-73, Hawaii Revised Statutes (HRS). In general, Subchapter 11 requires statewide reduction of GHG emissions to 1990 levels by 2020, and establishes a minimum reduction of 16% for affected facilities from the baseline year of 2010 unless it is determined that 16% reduction is unattainable.

This GHG ERP includes information required by Subchapter 11 to establish a 2020 facility-wide GHG emissions cap for the AES Hawaii facility. The following sections are included in this GHG ERP:

Section 2 – Facility Description contains information describing the facility, equipment, and the site location.

Section 3 – GHG Emission Reduction Plan Requirements identifies plan requirements set forth in Subchapter 11.

Section 4 – Facility Total Baseline GHG Emissions establishes the baseline emissions based on the most representative operating year for the period 2005 to present.

Section 5 – 2020 Facility-Wide GHG Emissions Cap includes a GHG control evaluation and proposes the GHG emission reduction plan for the facility.

Appendix A contains HAR §11-60.1 Subchapter 11: Greenhouse Gas Emissions

Appendix B contains calendar year 2010 annual baseline emissions calculations

Appendix C contains a simplified flow chart identifying steps included in the GHG control option evaluation

Appendix D contains the cost effectiveness summary and cost worksheets

2. FACILITY DESCRIPTION

AES Hawaii, located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu, commenced commercial operation in 1992. The facility is a coal-fired cogeneration plant that utilizes "clean coal" technology to generate steam and electricity. The facility is designed to sell sufficient quantities of steam to be a "Qualifying Facility" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). AES Hawaii is the single largest electric power generator on Oahu and provides 20% of the island's electrical energy demand. AES sells to Hawaii Electric Company (HECO) under a 30-year Power Purchase Agreement (PPA) that expires in October 2022. Approximately 97% of the plant's total capacity is committed to HECO under the PPA. The facility operates under Covered Source Permit (CSP) No. 0087-02-C, and has a total of two (2) electric generating units (EGU), Boilers A and B.

Boilers A and B are each Ahlstrom Pyropower Corp., circulating fluidized bed (CFB) steam boilers with a total maximum design heat input of 2,150 MMBtu/hr. Power output from the facility is currently limited to a maximum 180 MW-net (nominal) in accordance with facility's current PPA. In addition to generating electricity, a small percentage of total steam produced is sold to a nearby industrial facility. Each boiler is equipped with a limestone injection system for sulfur dioxide (SO_2) control, selective non-catalytic reduction (SNCR) for nitrogen oxide (NO_X) control, and fabric filter baghouse for control of particulate matter (PM) emissions. Boilers A and B are currently permitted to fire coal as the primary fuel, and limited amounts of wood fuel, tire derived fuel (TDF), spent activated carbon, and specification oil. Fuel oil is the startup fuel for Boilers A and B.

Emission sources installed at the facility include:

- Boilers A and B (coal as primary fuel with limited amounts alternative fuels)
- Coal Processing Equipment
- Limestone Processing Equipment
- One (1) five-cell (5-cell) cooling tower
- Ash handling equipment
- One (1) 60,000 gallon No. 2 fuel oil storage tank

The following stationary sources directly emit GHG emissions from the facility and will be included in the GHG control evaluation.

- Boilers A and B
- Limestone Dryers

3. GHG EMISSION REDUCTION PLAN REQUIREMENTS

On June 30, 2014, the Hawaii Department of Health (DOH) Clean Air Branch (CAB) amended HAR §11-60.1 to include Subchapter 11: Greenhouse Gas Emissions. Subchapter 11 implements Act 234, 2007 Hawaii Session Laws, which mandates a 2020 statewide GHG limit set equal to or below the 1990 statewide GHG emissions levels.

Subchapter 11 requirements generally apply to owners or operators of facilities with the potential to emit greater than 100,000 tons per year CO_2e. Affected facilities are required to develop a GHG ERP to establish facility-specific annual 2020 GHG emissions caps. Further, Subchapter 11 requires that the DOH conduct an annual evaluation of statewide GHG emissions in 2016 and thereafter to determine the progress of achieving the statewide GHG emission limit of 15.06 million tons per year CO_2e. If it is determined that the statewide GHG emission limit is met and projections indicate ongoing maintenance of the limit, the GHG ERP requirements will no longer apply to affected facilities.

The following procedure is included in Subchapter 11 for developing the GHG ERP (excerpts from Subchapter 11 given in italics). The full text of Subchapter 11 is included in Appendix A.

- **Establish facility-wide baseline GHG emissions (HAR §11-60.1-204(d)(1))**

  Calendar year 2010 annual emissions shall be used as the baseline emissions to calculate the required facility-wide GHG emissions cap, unless another baseline year or period is approved by the director. Baseline emissions shall be determined in accordance with section 11-60.1-115, separated between biogenic and non-biogenic emissions, and exclude all emissions of noncompliance with an applicable requirement or permit limit. The owner or operator shall include the data and calculations used to determine the baseline emissions. If calendar year 2010 is deemed unrepresentative of normal operations, then the owner or operator may propose an alternate baseline annual emission rate for the director's approval, as follows:

  (A) The owner or operator shall clearly document why calendar year 2010 is not representative of normal operations and why the proposed alternate year or period is more suitable based on trends, existing equipment and controls, scheduled maintenance, operational practices, and any other relevant information. Acceptable methods for determining alternate facility-wide baseline annual emissions include:

  (i) the facility-wide GHG emissions (less biogenic CO_2) based on the most recent representative year during the five-year period ending 2010;

  (ii) average facility-wide GHG emissions(less biogenic CO_2) over any consecutive two-year period during the five-year period ending in 2010;

(iii) average facility-wide GHG emissions (less biogenic CO_2) for the five-year period ending in 2010; or

(iv) comparable methods as approved by the director. The director will not consider the use of periods greater than five years from 2010, except for extreme cases such as where an affected source may not have been fully operational for an extended period of time.

(B) For newly permitted covered sources without a 2010 operating history, the owner or operator shall make the best estimate of normal operations based on contract agreements, available operational records, required scheduled maintenance, market forecast, or any other information for projecting the affected source emissions. Potential emissions shall not be used, unless the owner or operator can clearly demonstrate that the facility will be continually operating at the maximum capacity for each and every year.

The owner or operator shall provide all supporting documentation for the proposed alternate baseline emission rate. The director, based on available information, may reject and modify the baseline emission rate in establishing the final facility-wide GHG emissions cap.

- **Determine if 2020 facility-wide GHG emissions cap based on 16% reduction from baseline levels is attainable (HAR §11-60.1-204(d)(2))**

Determine the facility-wide GHG emissions cap in accordance with subsection(c), using calendar year 2010 or the proposed GHG baseline emission rate determined by paragraph (1) above. If the required emissions cap requiring a sixteen percent (16%) emission reduction from baseline year emissions is deemed unattainable, the owner or operator shall provide, as part of the reduction plan:

(A) The justification and supporting documentation of why the required emissions cap cannot be met; and,

(B) A proposal, for the director's approval, of an alternate emissions cap resulting in the maximum achievable GHG reductions.

In determining whether or not the required GHG emissions cap is attainable, the owner or operator of an affected source shall first conduct the GHG control assessment described in paragraphs (3) to (5). Available EPA guidelines for GHG Best Available Control Technology analysis, and GHG control measures by source type shall be used as applicable for this assessment.

- **Identify all available control measures (HAR §11-60.1-204(d)(3))**

Identify all available control measures with potential application for each source type, and all on-the-book control measures the facility is committed or will be required to implement affecting GHG emissions. At a minimum, the following shall be considered as applicable:

(A) Available technologies for direct GHG capture and control;

(B) Fuel switching or co-fired fuels;

(C) Energy efficiency upgrades;

(D) Combustion or operational improvements;

(E) Restrictive operations;

(F) Planned upgrades, overhaul, or retirement of equipment;

(G) Outstanding regulatory mandates, emission standards, and binding agreements; and

(H) Other GHG reduction initiatives that may affect the facility's GHG emissions. Unless the owner or operator of the source has direct ownership or legal control over a GHG reduction initiative, that initiative cannot be relied upon as a proposed control strategy. Identification of GHG reduction initiatives, whether or not the owner or operator has ownership or legal control, will serve to highlight their potential importance for reducing GHG emissions in the state. The owner or operator of an affected source will only benefit from a GHG initiative, if the initiative reduces or helps to reduce and maintain the source's GHG emissions below its permitted facility-wide GHG emissions cap.

- **Eliminate technically infeasible options (HAR §11-60.1-204(d)(4))**

  For any new control measure identified for the facility, eliminate all technically infeasible options based on physical, chemical, or engineering principles that would preclude the successful operation of the control with the applicable emission unit or source. Document the basis of elimination, and generate the list of technically feasible control options for further evaluation. All committed and required on-the-book measures shall remain on the list.

- **Control effectiveness and cost evaluation (HAR §11-60.1-204(d)(5))**

  List the technically feasible control options and identify the following for each control measure as applicable. All cost data shall be provided in present dollars.

  (A) Control effectiveness (percent pollutant removed);

  (B) Expected emission rate (tons per year CO_2e, pounds CO_2e/kilowatt-hour);

  (C) Expected emission reduction (tons per year CO_2e);

  (D) Energy impacts (BTU, kilowatt-hour);

  (E) Environmental impacts (other media and the emissions of other regulated air pollutants);

  (F) Any secondary emissions or impacts resulting from the production or acquisition of the control measure; and

  (G) Economic impact (cost effectiveness: annualized control cost, dollar/megawatt-hr, dollar/ton CO_2e removed, and incremental cost effectiveness between the control and status quo).

  For committed or required on-the-books control measures and any other GHG control initiatives, identify at a minimum, items (A) through (C) above. Considering the energy, environmental, and economic impact, determine the GHG control or suite of controls found to be feasible in achieving the maximum degree of GHG reductions for the *facility. Determine whether the required GHG emissions cap, pursuant to subsection (c) will be met. If an alternate cap must be proposed for approval, declare the proposed percentage GHG reduction and the alternate GHG reduction cap. Provide the justification and associated support information (e.g., references, assumptions, vendor quotes, sample calculations, etc.) to substantiate the control analysis and alternate GHG emissions cap.*

- **Proposed control strategy (HAR §11-60.1-204(d)(6))**

  Present the listing of control measures to be used for implementation in meeting the required or proposed alternate 2020 facility-wide GHG emissions cap. Include discussion of the control effectiveness, control implementation schedule, and the overall expected GHG CO_2e emission reductions (tpy) for the entire facility. Owners or operators shall also consider the following:

  (A) Affected sources may propose to combine their facility-wide GHG emissions caps to leverage emission reductions among partnering facilities in meeting the combined GHG emissions caps. If approved by the director, each partnering facility will be responsible for complying with its own adjusted GHG facility-wide emissions cap.

  (B) Except for fee assessments and determining applicability to this section, biogenic CO_2 emissions will not be included when determining compliance with the facility-wide emissions cap until further guidance can be provided by EPA, or the director, through rulemaking.

  (C) The approved facility-wide GHG emissions cap and the associated monitoring, recordkeeping, and reporting provisions will be made a part of the covered source permit, enforceable by the director.

4. FACILITY-WIDE TOTAL BASELINE GHG EMISSIONS

The first step in developing the GHG ERP is to establish facility-wide baseline GHG emissions based on calendar year 2010 emissions. If calendar year 2010 is deemed unrepresentative of normal operation, an alternative annual baseline emission rate meeting requirements of HAR §11-60.1-204(d)(1)(A) may be proposed.

S&L evaluated AES Hawaii's facility-wide operations for the period 2005 to present to determine if calendar year 2010 is representative of normal AES Hawaii operations. Based on review of annual fuel consumption rates, actual fuels consumed, boiler heat inputs, boiler heat rates, power generation, and capacity factors, it was determined that calendar year 2010 is representative of normal facility-wide operation. Therefore, facility total baseline annual GHG emissions for AES Hawaii have been based on calendar year 2010 emissions.

In accordance with HAR §11-60.1-115, baseline annual CO_2e emission rates shall be determined based on (1) stack test reports, continuous emissions monitoring data, or any other certified record, or (2) emission factors used in complying with 40 CFR Part 98, Mandatory GHG Reporting. Prior to calendar year 2011, CO_2 continuous emissions monitoring systems (CEMS) were not installed on the AES Hawaii Boilers A and B; therefore, baseline annual emissions from Boilers A and B have been based on representative emission factors obtained from 40 CFR Part 98 and 2010 annual material consumption rates. Calendar year 2010 baseline emissions are calculated as follows:

Facility-Wide Baseline Emissions (tpy CO_2e) = Facility-Total Baseline GHG Emissions (tpy CO_2e) – Facility Baseline Biogenic CO_2 Emissions (tpy CO_2)

Table 4-1 provides a summary of the AES Hawaii 2010 facility-wide baseline annual emissions; additional information, including material consumption rates and emission factors details are included in Appendix B.

Table 4-1: AES Hawaii 2010 Facility-wide Baseline Emissions

	CO_2		N_2O		CH_4		Total $CO_2e^{(1)}$
	Non-Biogenic, tons/yr	Biogenic, tons/yr	tons/yr, as N_2O	tons/yr, as $CO_2e^{(1)}$	tons/yr, as CH_4	tons/yr, as $CO_2e^{(1)}$	tons/yr
Boilers A and B (total)	1,668,138	0	28	8,627	191	4,015	1,680,781
Limestone Dryers	822	0	0	2	0	1	824
Facility-Wide Total	1,668,960	0	28	8,629	191	4,016	1,681,605

Note 1. CO_2e emissions calculated based on 2010 GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, N_2O = 310, CH_4 = 21).

5. 2020 FACILITY-WIDE GHG EMISSIONS CAP

This section provides an evaluation of GHG emission reduction options available to AES Hawaii to determine whether a 16% reduction in GHG emissions from the 2010 baseline is attainable, and if not, to identify an alternative emissions cap resulting in the maximum achievable GHG emissions reductions.

This analysis generally follows EPA's "top-down" approach for determining best available control technology (BACT)[1] and EPA guidelines for conducting a GHG BACT[2] analysis, which is consistent with the requirements of Subchapter 11. The "top-down" approach utilized in this evaluation includes the following steps:

Step 1: Identify Potentially Feasible GHG Control Options
Step 2: Evaluate the Technical Feasibility of Potential GHG Control Options
Step 3: Rank the Technically Feasible GHG Control Options by Effectiveness
Step 4: Evaluate the Technically Feasible GHG Control Options for:

- Economic Impacts
- Environmental Impacts
- Energy Impacts

Step 5: Proposed Control Strategy for GHG Emissions

A more detailed description of each step in the control technology analysis is provided below. A simplified flow chart identifying each step of the control technology evaluation is included in Appendix C.

Step 1 - Identify Potentially Feasible GHG Control Options

The first step in the GHG control analysis is to identify all available control options to reduce GHG emissions. Available GHG control options are those strategies with a practical potential for application to the emission unit.

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[1] EPA Office of Air Quality Planning and Standards, *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting*, Draft, October 1990.

[2] EPA Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011.

Step 2 – Technical Feasibility of Potential GHG Control Options

The second step in the GHG control analysis is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Options that are not technically feasible for the intended application are eliminated from further review.

Step 3 - Rank the Technically Feasible GHG Control Options by Effectiveness

All technically feasible options are ranked in order of overall control effectiveness. Control effectiveness is generally expressed as GHG emitted after the implementation of the control option. The most effective GHG control option is the strategy that achieves the lowest emissions level.

Step 4 - Evaluate Technically Feasible GHG Control Options

After identifying the technically feasible control options, each option, beginning with the most effective, is evaluated for associated economic, energy and environmental impacts. In the event that the most effective control alternative is shown to be inappropriate due to energy, environmental or economic impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy or economic impacts.

Step 5 - Select Control Strategy for GHG Emissions

Based on the results of Steps 1 through 4, Step 5 provides the proposed GHG control strategy for the facility.

5.1 GHG CONTROL ASSESSMENT

The top-down approach described above is applied for the control of GHG emissions from the AES Hawaii facility. GHG emissions sources at AES Hawaii include Boilers A and B which are CFB boilers with a common steam turbine generator that currently generates up to 180 MW-net (limited by the PPA), and limestone dryers that are driven by diesel engines.

5.1.1 Step 1: Identify Available GHG Control Options

Step 1 of the GHG control technology process includes identifying all "available" GHG control options that have a potential for practical application to the source under consideration.[3] This does not affect the discretion of the permitting authority to exclude options that would fundamentally redefine the proposed source or modification.[4] To be included in a control technology evaluation, available control technologies must have a "practical potential for application to the emissions unit and the regulated pollutant under evaluation."[5]

Any requirement that would compel AES Hawaii to evaluate alternative generating technologies (e.g., boiler designs, combustion turbines, gasification systems, etc.) would change the basic purpose and design of the facility, and is outside the scope of this GHG control technology analysis. EPA reiterates this position in the GHG Permitting Guidance Document, with respect to alternative fuels, by explaining that fuels which result in fewer GHG emissions can be considered in the analysis; however, "EPA has recognized that the initial list of control options for a BACT analysis does not need to include 'clean fuel' options that would fundamentally redefine the source."[6] In assessing whether an option would fundamentally redefine a proposed source or modification, EPA recommends that the "permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the facility in its application" and then "take a 'hard-look' at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business for the proposed facility."[7]

Table 5-1 identifies GHG control categories listed in HAR §11-60.1-204(d)(3) and available control measures that have potential application to AES Hawaii. Control technologies with potential application to reduce facility-wide GHG emissions from AES Hawaii were identified based on a comprehensive review of available information, including, EPA's RACT BACT LAER Clearinghouse (RBLC) Database; reports published by the U.S. Department of Energy (DOE) national laboratories; information available regarding industrial CO_2 separation processes;

[3] EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA-457/B-11-001, March 2011, page 30.
[4] *id.*
[5] EPA, New Source Review Manual, p. B.5.
[6] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, p. 29.
[7] *id.*, at 27.

published information from control technology vendors and engineering/environmental consulting firms; a review of technical journals, reports, industry seminars and presentations.

Table 5-1: List of Potential GHG Control Options

GHG Control Category (HAR §11-60.1-204(d)(3))	Potential GHG Control Options for AES Hawaii
Carbon Capture and Sequestration	Carbon Capture • Monoethanol amine (MEA) absorption Carbon Sequestration • Geologic sequestration • Seawater Sequestration
Fuel switching or co-fired fuels	Co-firing • Natural gas • Fuel oil • Biomass • Alternative fuels
Energy efficiency upgrades (demand-side)	NA
Combustion or operational improvements	- Heat rate improvements - Combined heat and power - Reduce limestone consumption - Replace oil-fired limestone dryers with electric dryers.
Restrictive operations	Reduce capacity factors for Boilers A and B
Planned upgrades, overhaul, or retirement of equipment	Planned upgrades, overhaul, or retirement of equipment
Outstanding regulatory mandates, emissions standards, and binding agreements	NA
Other GHG reduction initiatives	NA

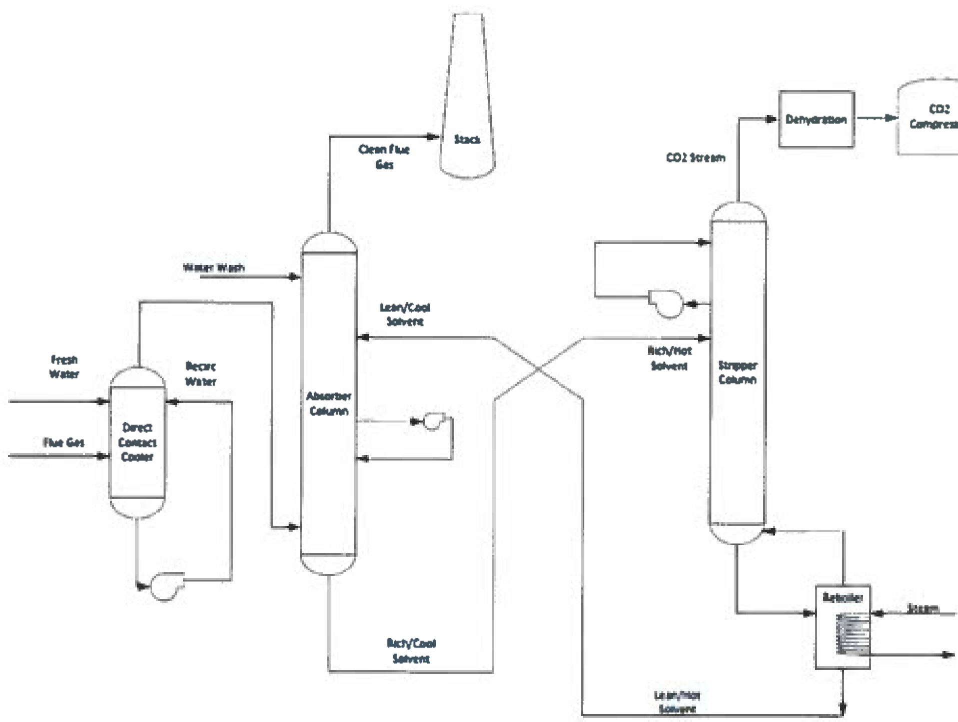
5.1.2 Step 2: Technical Feasibility of Potential GHG Control Options

The second step in the GHG control analysis is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. A demonstration of technical infeasibility must be based on physical, chemical, and engineering principles, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility. Options that are technically infeasible for the intended application are eliminated from further review.

5.1.2.1 Carbon Capture and Sequestration

Chemical absorption systems are currently used to separate and capture CO_2 in industrial applications as well as various coal-fired power plants in the U.S. on a slipstream scale. In general, these systems are designed to separate CO_2 from other gases in the exhaust gas stream by a chemical absorption reaction that forms a loosely bonded intermediate compound consisting of CO_2 and a solvent. After the absorber module, the intermediate compound is transferred to a regenerator where it is heated (usually with steam) causing it to break down into separate streams of CO_2 and solvent. The solvent stream is recycled back to the absorber; the solvent most often used to capture CO_2 is monoethanol amine (MEA). The CO_2 is cooled, dehydrated, and compressed before it is ready for storage or commercial use. A simplified process flow diagram of the MEA separation process is shown in Figure 5-1.

Figure 5-1: General Process Flow for MEA-Based CO_2 Capture and Transportation



Some commercial applications for CO_2 capture have been installed to collect CO_2 as a useful product to be sold commercially. The MEA chemical absorption process in conjunction with other separation technology can produce a high quality CO_2 stream suitable for enhanced oil recovery (EOR) applications or for food grade purposes. If the CO_2 cannot be sold, it must be stored underground permanently. Demonstration projects are currently underway across North American and elsewhere around the world to demonstrate geological and seawater sequestration.

Several technical issues present themselves if MEA absorption is going to be used for CO_2 capture on utility-scale fossil fuel-fired boilers. First, for effective CO_2 absorption, SO_2 concentrations in the flue gas should not exceed approximately 10 ppm; when SO_2 is present in the flue gas, heat stable salts are created that deactivate the solvent. Although AES Hawaii operates a CFB boiler with SO_2 and acid gas control, SO_2 emissions will remain above the 10 ppm threshold. The unit would likely be required to install a wet-FGD system to reduce SO_2 emissions to the required amount to prevent deactivation of the MEA solvent.

Second, a slipstream MEA absorption system retrofit at AES Hawaii would require significant space. As an example, the footprint for a full-scale MEA system would be approximately equal to the footprint of the existing boiler and turbine buildings.

Accommodating the auxiliary power and steam required to operate a slip stream CO_2 capture system designed to achieve 16% reduction would be expected to reduce power output by 10%. In order to meet the auxiliary power requirement for a carbon capture system, the unit would have to either increase firing of the boiler to increase gross power output, reduce the net power output for the facility, or install a new auxiliary electric generating unit (e.g., oil-fired combustion turbine). If the steam required for the process is extracted from the existing turbine's Intermediate Pressure/Low Pressure (IP/LP) crossover line, the LP section of the steam turbine might not continue to operate properly at full or partial loads with limited steam supply. The AES Hawaii station is currently equipped with steam extraction between the IP/LP crossover and designed to supply up to 40,000 lb/hr of steam to a nearby industrial facility. If carbon capture is explored at AES Hawaii on a slipstream scale, the steam that is currently sold offsite could potentially be used instead for part of the carbon capture system requirement. However, the facility is currently a "qualified facility" under PURPA, and if the facility is to maintain that status, an alternative source of steam would be required for carbon capture uses. One option would be to install a new steam generating system (e.g., oil-fired auxiliary boiler, oil-fired combustion turbine with steam generator) to supply the necessary steam for the process. Inclusion of a new auxiliary power and steam source would add space demands to the property requirements and would increase the facilities GHG emissions.

Overall, MEA absorption technologies have been demonstrated as a technically feasible process operation for industrial applications. In addition, DOE-funded slipstream scale applications have been installed demonstrated on coal-fired power plants located in the U.S. The DOE is currently in the process of providing funding for additional research into alternate carbon capture technologies and absorption solvents.

While the carbon capture process has been proven as a technically feasible CO_2 reduction strategy, the location of the AES Hawaii station hinders the application of sequestration techniques. The Hawaiian Islands have no proven CO_2 geological storage sites nor are there opportunities for EOR. Seawater sequestration is another option that includes two potential options for injecting the CO_2 into the ocean: diffusing CO_2 columns 1,000 m below the surface or creating dense phase CO_2 "lakes" 3,000 m deep.[8]

The two ocean storage options have been tested in the laboratory and in small-scale field tests, but the techniques have not been demonstrated on a large scale. According to the IPCC, "Further research and development would be needed to make technologies available, but no major technical barriers are apparent." Additionally, there are legal concerns that need to be addressed prior to implementing large scale CO_2 ocean sequestration. One concern is that CO_2 will fall under the category of "waste" as written in the London Convention, potentially prohibiting the disposal of it in oceans.[9] Because CO_2 sequestration options are not currently available in Hawaii, carbon capture and sequestration it is not considered a technologically feasible GHG control option for AES Hawaii and is not considered further in this analysis.

5.1.2.2 Fuel Switching or Co-Fired Fuels

5.1.2.2.1 *Alternative Fuels*

CFB boilers tend to be very robust when it comes to the type of fuel that is possible to fire, due to the nature of the combustion process and the long residence time the fuel has in the boiler. Boilers A and B currently fire a fuel blend consisting mostly of coal, but also small amounts of spent activated carbon, used "specification" oil, and tire derived fuel (TDF). The spent activated carbon fired at AES Hawaii is a high energy fuel source that comes from carbon filter beds that were originally used in water treatment sources. Used "specification" oil (or spec oil) is

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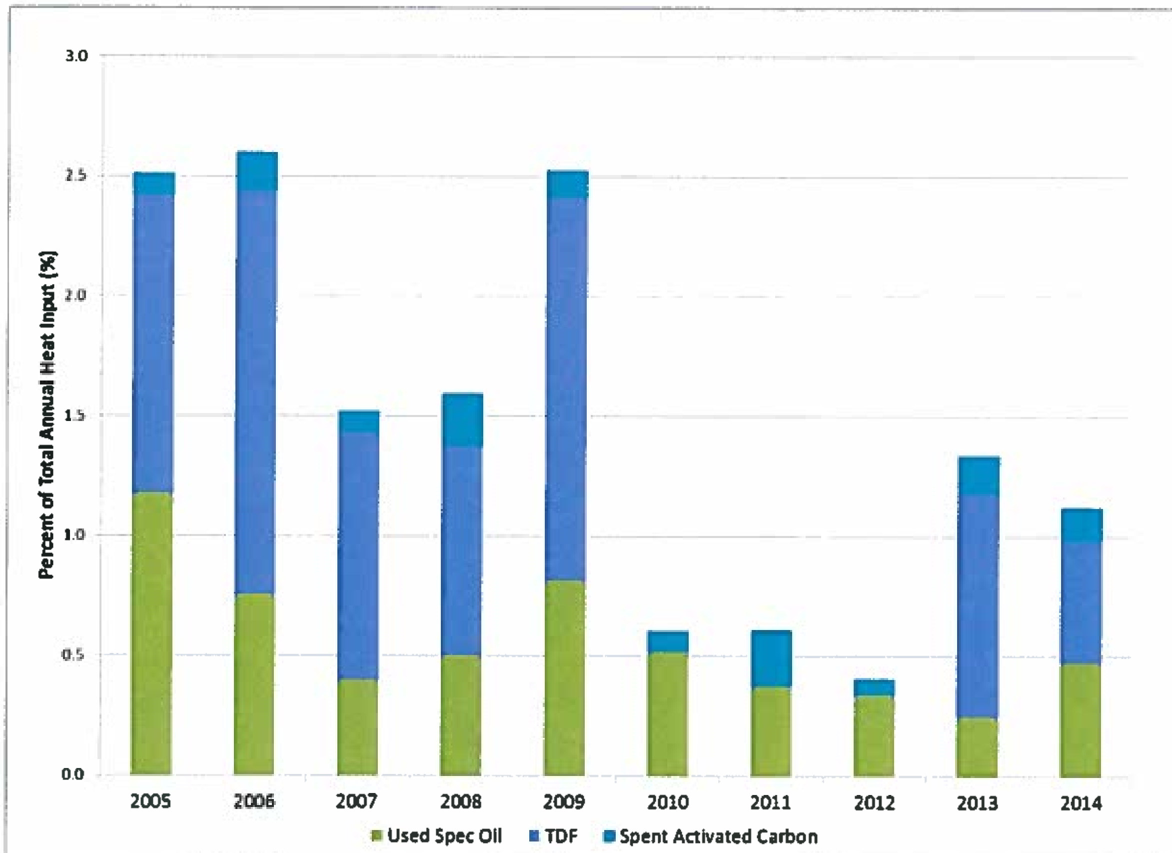
[8] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.
[9] Purdy, Ray. "The Legal Implications of Carbon Capture and Storage Under the Sea." Sustainable Development Law & Policy, Fall 2006, 22-26.

essentially used motor oil supplied by a local source on Oahu. Only Boiler B is currently designed to burn this fuel, up to 3.5%. TDF is currently obtained from a local supplier. Figure 5-2 shows the total alternative fuels fired in Boilers A and B for the period 2005 to 2014 as a percent of total annual boiler heat input. Annual alternative fuel use has ranged from approximately 0.5% to 3% over the last 10 years.

Figure 5-2: Historical Alternative Fuel Firing at AES Hawaii (Boiler A & B)



The facility's CSP currently allows for limited firing of alternative fuels (approximately 5% maximum). Although increasing the amount of alternative fuels fired on an annual basis would require amending the CSP, increased amount of alternative fuels fired could reduce the annual CO_2 emissions for the facility. With the exception of spent activated carbon, the CO_2 content of alternative fuel is lower than that of coal (see Table 5-2).

Table 5-2: Fuel CO_2 Emission Factor Comparison

Fuel	CO_2 Emission Factor(1) (lb/MMBtu)
Spent Activated Carbon	250.6(2)
Bituminous Coal	205.6
TDF	189.5
Specification Oil	163.1
#2 Fuel Oil	163.1

Note 1. Emission factors from Table C-1 to Subpart C of Part 98.
Note 2. Emission factor for pet coke.

Based on the above CO_2 emission factors, while it is technically possible for AES Hawaii to reduce GHG emissions by reducing coal use and increasing firing of TDF and oil, the alternate fuels are supplied to AES Hawaii directly from sources located on the island and are limited in availability. The units typically fire as much spec oil, activated carbon, and TDF that is available, and it is unlikely that local supplies will increase. Therefore, due to limited sources of alternative fuels, increased firing of alternative fuels is not considered to be a technically feasible option for GHG control.

5.1.2.2.2 *Natural Gas*

GHG emissions associated with firing natural gas are approximately 40% lower than coal-fired GHG emissions, on a lb/MMBtu basis. This means that natural gas would have to supply up to 35% to 40% of total heat input to achieve up to 16% GHG reduction from AES Hawaii. Because adequate supplies of natural gas are not currently available on Oahu nor are plans to make liquefied natural gas (LNG) available prior to 2019, natural gas firing is not a technically feasible GHG control option for AES Hawaii.

5.1.2.2.3 *Biomass*

GHG emissions from biogenic sources, such as wood, wood waste, forest residue, agricultural material, or other biomass materials, are excluded from reported facility total annual GHG emissions. Biomass co-firing is a potential GHG control option for AES Hawaii. Categories of raw biomass that may be available to AES Hawaii include fast growing biomass and mature biomass. Examples of fast growing biomass sources include, but are not limited to, switchgrass, straw, and wheat chaff. More mature or slow growing sources, such as forest residuals, are the byproducts of harvesting timber for lumber and pulp/paper mills. This material includes tree tops, limbs, bark, stumps, and leaves/needles from harvested trees. This material is typically left in the forest, but can be collected for use as wood fuel. Collection can be done by bundling or chipping. Whole logs can also be harvested and chipped for fuel.

Biomass supply can also come in the form of pelletized wood. These pellets are preformed prior to shipment, which results in easier fuel handling practices; however, this can often come at a premium cost. Additionally, the pellets are much lower in moisture content than chipped biomass supplies.

With regard to boiler performance, as received biomass materials often have moisture contents in the 40-50% range. The high moisture percentage would reduce the boiler efficiency thus requiring more fuel to be burned. Biomass moisture content may be reduced by incorporating wood pellets. Another major concern for co-firing is that residuals tend to have higher overall ash content and the ash tends to have higher concentrations of troublesome minerals such as sodium (Na) and potassium (K). Ash content can also be increased by dirt that is collected with the residual materials. Due to lower melting temperatures, these ash constituents cause fouling and slagging issues on heat transfer surfaces in the boiler. In addition, hot ash carry-over may have adverse effects on downstream equipment, such as damaging the reverse gas fabric filter baghouse. Before implanting this technology on a coal-fired plant, an evaluation would have to be conducted to ensure that biomass firing will not adversely affect the boiler components, and that carry-over of burning wood ash particles is minimized. Other constituents of the biomass may result in increased flue gas emissions.

Fuel handling is also a potential concern with biomass co-firing. It is often required to send the delivered product through grinding equipment that reduces product size to assure better handling and metering into the boiler. For pulverized coal boilers, suspension burning equipment is also required to ensure the wood material is injected properly in the boiler to assure minimal carryover. With CFB boilers, fuel is fed into the boiler on the top of the bed using screw feeders.

Eucalyptus and construction waste are the most commercially available biomass source on the Hawaiian Islands. AES Hawaii performed two biomass test burns of eucalyptus biomass in 2011 and construction waste in 2015, co-firing up to 16% wood on a total heat input basis. During these trials, the station experienced several problems, such as fuel bridging in the coal bunkers before the feeders. However this fuel was delivered and fed to the boiler through the normal coal delivery system which was not designed to handle long fibrous biomass. Even when the biomass was further chipped (processed to a smaller size) there still were bridging issues.

While CFB boilers can typically incorporate woody biomass resources into the combustion bed, several modifications and design boiler performance issues have to be evaluated at AES Hawaii, based on previous experience. To accommodate biomass fuel, the boiler island would require modifications that include adding a live bottom storage bin located near each boiler, each with a screw conveyor to deliver the material into the boiler on top of the bed. Additional metering systems would have to be incorporated as well. Major additions to the fuel yard storage area and handling include walking floor delivery trucks or truck tippers, additional segregated storage piles, reclaim systems, and additional material processing (chipping) to meet sizing criteria.

In order to achieve 16% CO_2 reduction, the biomass firing rate would have to be approximately 25% by weight, depending on the quality of the delivered biomass. Co-firing biomass at those levels will also affect other flue gas emission rates. During recent eucalyptus test burns in 2011 and construction debris test burns in 2015, hydrochloric acid (HCl) emissions increased. Table 5-3 compares HCl emissions measured during test burns to HCl emissions during normal operations. Based on test results, increases in HCl emissions with biomass firing would have to be mitigated to achieve compliance with the Mercury and Air Toxics Standards (MATS) rule.

Table 5-3: HCl Emissions Test Results

	Boiler A HCl Emissions		*Boiler B HCl Emissions*	
	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu
MATS Emissions Stack Testing(1) (Nov 2015)	2.39	0.0018	2.87	0.002
2011 Eucalyptus Test Burn	3.08	0.0027	3.685	0.0032
2015 Construction Debris Test Burn	4.62	0.0037	11.58 (Method 5/26A) 6.85 (Method 26A only)	0.0087 (Method 5/26A) 0.0055 (Method 26A)

Note 1. The applicable MATS HCl limit for AES Hawaii is 0.0020 lb/MMBtu (see Table 2 to Subpart UUUUU of Part 63)

Recommended HCl mitigation technologies typically include dry sorbent injection (DSI) systems. To ensure the MATS HCl limit is met, sorbent would be injected upstream of the baghouses. Since hydrated lime has a preferential selection to react with HCl, rather than SO_2 and SO_3, the DSI system would be designed with this sorbent in mind. A DSI system using hydrated lime would include storage silos, pneumatic conveying lines, injection lances, blowers, driers, and chillers.

Co-firing up to 25% by weight biomass in coal units is considered technically feasible taking into account the design aspects listed above. Consuming approximately 25% biomass by weight in Boilers A and B would require in the range of 150,000 to 200,000 tons per year of biomass. The National Renewable Energy Laboratory (NREL) has prepared a "Biomass Resources" exhibit which identifies the island of Oahu's potential biomass reserve supply at 150,000 to 250,000 tons per year. However, an in-depth biomass fuel supply study would be required to determine the actual long-term availability for AES Hawaii. The study would review the sustainability of the woody biomass supply on the island of Oahu, and it would review the ability to procure a long-term contract with the suppliers. Depending on the availability of this supply for use at AES Hawaii, biomass firing may either have to be limited based on island supply or biomass would have to be imported to Hawaii.

Co-firing 25% biomass would increase the net unit heat rate, since it decreases overall boiler efficiency by approximately 2%. The increased boiler heat input requirement could be met by firing additional biomass. Assuming the DOH continues to exclude biogenic CO_2 emissions from reported facility total annual GHG emissions, biomass co-firing has the potential to reduce CO_2 emissions by up to 16% at AES Hawaii. This would potentially require importing additional biomass to the island. Therefore, the analysis will include two evaluations: firing up to 150,000 tons per year of local biomass supply (approximately 20% by weight) and firing 25% by weight biomass in the form of wood pellets shipped from overseas. Importing biomass would potentially increase lifecycle GHG emissions rather than using local supplies; however, these lifecycle emissions are not included in this evaluation.

5.1.2.2.4 *Fuel Oil*

Fuel oil is another fuel source that produces less CO_2 per Btu than coal. The facility already uses fuel oil during startup of the boilers, thus is already equipped with burners and storage tanks that are adequate for firing fuel up to 30% load during unit startup. For the purpose of this evaluation, it is assumed that the unit will be capable of firing up to 30% of total heat input on a continuous basis without requiring major boiler modifications. However, additional fuel oil storage capacity would be required, along with supply pumps and piping. If more than 30% fuel oil co-firing were to be incorporated, additional modifications would be required. New burners would have to be installed to increase injection rate. Additionally, operational practices would have to be modified to discontinue reinjection of bed ash, due to contamination with unburned oil. To mitigate safety concerns, the bed ash would have to be removed from the hoppers, cooled with water spray, and neutralized.

Another major concern for fuel oil co-firing is the potential for oil carry over. Unburned oil and its impact would have to be evaluated for potential contamination of downstream equipment including the fabric filter bags. A safety evaluation would also have to be conducted.

Based on CO_2 emission factors included in Table 5-2 and the fuel oil heating value, to achieve 16% CO_2 reduction it is estimated that the fuel blend would have to consist of over 76% fuel oil. This would significantly impact the gas and steam temperatures in the boiler, due to the higher heat of combustion of fuel oil. To accommodate these higher temperatures, the majority of the boiler water walls, including steam surface, would have to be upgraded with different materials. Heat transfer surface area would also have to be modified to ensure steam temperatures are within the design operating range for the steam turbine. The vast amount of modifications to the boiler would be considered redefining the source, therefore, achieving 16% CO_2 reduction by co-firing fuel oil is not considered technically feasible.

As an alternative, the boilers are currently designed to fire up to 30% fuel oil on a heat input basis during startup. If 30% of the heat input is provided consistently by fuel oil firing, annual CO_2 emissions would be reduced by 6%. However, due to the heat of combustion of fuel oil compared to coal and the location of the igniters, the fluidized bed temperatures may be too high, causing the bed clinker in the bottom of the boilers. To minimize the potential of sintering the bed, the fuel oil burners would be relocated to a boiler elevation higher above the fluidized bed.

If modifications to the boiler are not possible, it is estimated that 10% fuel oil firing would be possible without burner relocation. Additional evaluations would be required to determine the impact on the boiler while firing up to 10% fuel oil for extended periods. Barring the results of additional evaluations and design considerations described above, co-firing fuel oil in quantities up to 10% by total heat input is considered technically feasible without burner modifications and could reduce GHG emissions by approximately 2%.

Table 5-4: Fuel Oil Co-Firing Results

Fuel	Units	Baseline	*10% Fuel Oil by Heat Input*	*30% Fuel Oil by Heat Input*	*76% Fuel Oil by Heat Input**
Bituminous Coal	1000 tons/yr	744	669	519	*176*
Fuel Oil	1000 gals/yr	75	11,476	34,429	*87,109*
% CO_2e Reduction		NA	2.1	6.3	*16.0*

*Note: 76% fuel oil co-firing is considered redefining the source, and, therefore, is not considered to be a technically feasible option.

This study does not take into account the lifecycle emissions due to the truck traffic required to deliver the required increased amount of fuel oil to the station on an annual basis.

5.1.2.3 Energy Efficiency Upgrades

It is S&L and AES's interpretation that energy efficiency upgrades referenced in the rule are attributed to demand-side upgrades. AES Hawaii is an independent power producer (IPP) that is currently operating under a PPA to supply electricity to HECO. AES Hawaii does not own or operate the electricity transmission system or have control over end-user activities where demand side energy efficiency upgrades can be implemented. Therefore, energy efficiency upgrades are not an available GHG control option for AES Hawaii.

5.1.2.4 Combustion or Operational Improvements

5.1.2.4.1 *Heat Rate Improvements*

The heat rate of a facility is an indicator of efficiency, measuring the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output, is used track the performance and efficiency of thermal power plants.[10] Reduction in fuel consumption to generate the same amount of power can directly reduce CO_2 emissions of a coal-fired power plant. For every percent improvement in heat rate, it can be concluded that 1% CO_2 is reduced. Therefore, potential heat rate improvements at the AES Hawaii facility have been evaluated to identify their potential to reduce CO_2 emissions.

The EPA has identified several potential heat rate improvements (HRI) as part of the technical support document for the Clean Power Plan that may result in system efficiency gains, summarized in Table 5-5.[11] While there are many HRI options for the industry as a whole, not all of listed options are applicable to each plant. Reasons that HRI strategies may not be technically applicable include existing technology restrictions, current employment of best maintenance practices, not having the technology installed (e.g. SCR), operational profile, and others.

S&L has provided added comments of applicability to the AES facility to the list of potential heat rate improvement options.

[10] The average, annual operating heat rate of U.S. coal-fired power plants is approximately 10,400 Btu/kWh. Because operating units report heat rates that include performance at all levels, the numbers are usually significantly higher than the full load design heat rate.
[11] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602

Table 5-5: Heat Rate Improvement Options

Boiler Island	Description	Applicability
(1) Material Handling	Upgrade to variable frequency drives (VFDs) on coal handling equipment, improve pulverizers, and convert water-sluicing to dry drag chain system for bottom ash handling.	Upgrades to pulverizers are not applicable to CFB boilers. Additionally, CFB boilers do not use wet bottom ash handling systems.
(2) Economizer	Upgrade/increase heat transfer in economizer section to increase heat rate and reduce outlet temperature.	Additional tubing added to boiler would lead to increased fouling.
(3) Boiler Control System	Install adaptive control for optimized air to coal ratio, and steam tempering to properly balance plant response to load changes identifying low heat rate operation regime. Also known as Neural Network (NN).	Applicable
(4) Sootblowers	Strategically allocate sootblowing steam to specified areas on heat transfer surfaces requiring soot and ash deposit removal. Also known as intelligent sootblower (ISB).	Applicable
(5) a. Air heater leakage mitigation	Improve seals between heater's gas and air side to reduce flue gas flow to induced draft (ID) fan and auxiliary equipment.	Tubular air heaters have limited in-leakage.
(5) b. Air heater acid dew point reduction	Lower sulfuric acid dew point of the flue gas to increasing the amount of heat extracted through the air heater with modified air heater.	Applicable
Turbine Island		
(6) Steam Turbine	Install technologically advanced steam turbine components to increase turbine efficiency.	Applicable
(7) Feedwater heater	Add additional surface to improve heat transfer efficiency.	Best Maintenance Practices[1]
(8) Condenser	Improve condenser tube cleaning by using metal cleaners or plastic brushes and maintaining regular offline cleaning schedules.	Best Maintenance Practices[1]
(9) Boiler Feedwater Pump	Rebuild boiler feed pump in an overhaul or upgrade.	Turbine driven feedwater pumps are typically not implemented on small units of 200 MWg.

Flue gas system		
(10) Forced draft (FD) and induced draft (ID) fan improvement	Convert from centrifugal to axial fans.	The unit is equipped with centrifugal fans. Addition of VFDs would be more cost effective.
(11) Variable-frequency drive (VFD) motors	Install variable frequency motor controllers to enable fans to reduce power consumption during startup and at reduced loads.	Applicable
Air pollution control equipment		
(11) Flue gas desulfurization (FGD) system	Remove venturi throat in absorber, improve flow distribution to lower pressure drop, shutoff a slurry spray level/pump, and install VFD on slurry feed pumps.	The unit is not equipped with an FGD system.
(12) Electrostatic Precipitator (ESP)	Upgrade both energy management system and transformer/rectifier (T/R) sets on existing ESPs to reduce power consumption.	The unit is not equipped with an ESP.
(13) Selective catalytic reduction (SCR)	Reduce pressure drop across SCR system and utilize secondary air instead of electric heaters for ammonia dilution.	The unit is not equipped with an SCR system.
Water treatment system		
(14) Water Treatment System	Improve quality of water used in the steam cycle to reduce tube scaling as well as lower blowdown required to improve efficiency and reduce heat rate.	Negligible improvement potential on a unit of AES Hawaii's size.
(15) Cooling Tower	Convert cross-flow configuration to a counter-flow design and increase heat transfer surface with advanced film fill packing material to improve thermal efficiency.	The cooling tower was recently rebuilt to improve performance.

Notes:

1. Best Maintenance Practices are measures that have already been implemented by the facility to ensure repairs and upgrades are made to heat rate intensive components on a regular basis.

AES Hawaii has developed and implemented a comprehensive inspection and preventive maintenance program designed to address boiler operation, maintenance, and efficiency. The program includes routine inspection of major facility components including the boiler, tubular air heaters, and steam turbine. AES Hawaii's preventive maintenance program is designed to identify and, where practical, implement routine equipment replacements that minimize overall auxiliary power requirements. Implementation of a cycle efficiency program ensures that the units achieve a heat rate as near as practicable to design conditions.

After review of AES Hawaii operating data, reading O&M manuals, and interviewing plant operators and engineers, S&L identified the most viable HRI strategies that have potential to provide improvements of approximately 0.5% and greater. All other HRI strategies were eliminated due to site-specific inapplicability and/or insignificant reduction potential in CO_2 emission rates.

The options identified as potential sources for significant heat rate improvements at AES Hawaii are:

(1) Control system upgrades
(2) Sootblower improvements
(3) Air heater outlet temperature reduction
(4) Turbine upgrade
(5) VFDs

5.1.2.4.1.1 Control System Upgrades

Unit operation can oftentimes benefit from upgrading the boiler control systems. Real-time data analysis, control, and better data logging can help operators hone in unit operating parameters. Neural network systems are one potential upgrade to existing controls that can provide optimized operation; however, these are found to be implemented less and less. State-of-the-art distributed control systems (DCS) and additional instrumentation and equipment to improve system operations have the ability to provide similar benefits as the neural network systems. These upgraded systems allow control room operators to understand and react better to performance issues within the boiler and turbine island. Parameters including boiler temperature, steam temperatures, fuel feed rates, and condenser temperatures, can be tracked to understand and optimize performance as they relate to other parameters.

Since the unit was constructed in the early 1990s, the DCS has not been fully upgraded. Only portions of the system have been upgraded as new equipment has been installed. An upgrade to the state-of-the-art DCS along with additional controllable parameters is predicted to provide up to 0.5% improvement in heat rate, by allowing control room operators to optimize boiler performance.

5.1.2.4.1.2 Sootblower Improvements

An advantage of CFB boilers is the ability to fire a wide variety of coals that allow flexibility when it comes to selecting a fuel supply. Because fuel characteristics can vary widely among different coal types, there is the potential that the most cost-effective fuel will also have a high fouling potential. Fouling of the boiler tubes can reduce steam temperatures that negatively impact the unit heat rate. Steam sootblowers can be utilized to maintain clean boiler tube surfaces.

Some of the fuels that are currently fired at AES Hawaii have fouled the back-pass surfaces even when the soot blowers that are currently installed operate continuously. Nevertheless, even with continuous sootblowing, fouling in Boilers A and B is reducing boiler performance. Since AES cannot base coal purchases solely on fouling potential, another option is to improve sootblower performance and maintenance and potentially install additional sootblowers in the boiler. Sootblower improvements may improve the main steam temperature by 15°F and reheat steam temperatures by 25°F on a consistent basis, resulting in a heat rate improvement of 0.7%, achievable on a long term basis. Better heat transfer in the back pass will improve air heater exit gas temperatures as well.

5.1.2.4.1.3 Air Heater Outlet Temperature

Air heaters are used to provide heat transfer between inlet boiler air and hot flue gas. Air heaters can come in various forms, but regenerative air heaters with rotating heating elements are the most common. Boilers A and B are equipped with tubular air heaters which are essentially large shell and tube heat exchangers. Using the hot flue gas to preheat the air going into the boiler, the combustion process becomes more efficient. Operating air heater flue gas outlet temperatures too low can lead to condensation of acid gases, which may lead to corrosion of equipment and ductwork. With these design considerations in mind, air heater outlet temperatures are typically around 250-350°F, depending on unit configuration, boiler type, and fuel burned. If the flue gas operating temperatures could be lowered, then the combustion air is further preheated, increasing the overall efficiency.

To mitigate concerns for corrosion, air heater outlet temperatures are typically controlled at 20-30°F above the acid dew point, which is a function of the fuel sulfur content and ultimately SO_3 concentrations in the flue gas. AES Hawaii typically fires coals with mid-range sulfur concentrations (0.5-1.5 wt%), thus acid dew points are expected to be relatively low due low SO_3 concentrations. The limestone in the CFB is very effective at reducing SO_2 concentrations, but also provides some reduction of other acid gases, such as SO_3, HCl, and HF. Based on operating firing mid-range sulfur content fuel and limestone injection in the CFB, it was anticipated that the units would be able to operate with low air heater outlet temperatures.

PI data was analyzed from the 2015 time frame to determine the inlet and outlet temperatures of each boiler's air heater. Additionally, this data was compared to the SO_2 concentration at the outlet of the boiler, since other acid gas concentrations are not measured on a continuous basis. To determine the theoretical outlet temperature that the unit could operate at without concerns for corrosion, the acid dew point was estimated. Table 5-6 compares actual minimum air heater temperatures to theoretical minimum air heater temperatures.

Table 5-6: Theoretical AH Temperatures

	Actual SO_2 Outlet Concentration *ppm*	*Actual Minimum AH Outlet Temperature* *°F*	*Theoretical Minimum AH Outlet Temperature*$^{(1)}$ *°F*
Boiler A - AH Annual Average	37.8	275	244
Boiler B - AH Annual Average	37.1	285	244

Note 1. Theoretical minimum AH temperature based on 40°F above the calculated acid dew point

Based on the analysis completed, it is expected that on an annual average basis, each boiler could reduce air heater temperatures by between 30-40°F. However, to prevent backend tube corrosion, steam coils would be installed to pre-heat the combustion air prior to the first tube bank. This will increase the average cold end temperature further, which should mitigate corrosion concerns, especially during unit startup and low load operation. The steam coils would consume approximately 20,000 lb/hr of steam, increasing the net unit heat rate. This increase would be offset by the improvement in seal between the air and gas side, due to the reduction in corrosion. Thus it is expected that the steam coils alone would have a zero net effect on the heat rate.

Industry literature suggests that coal-fired units should maintain a minimum average back-end temperature – average of the cool inlet air and warm outlet flue gas – above 155°F at the fuel sulfur range consistent with AES Hawaii.[12] Reducing the average gas outlet temperature to 250°F, this will maintain a back-end temperature of 165°F, which provides a 10°F margin for changes in weather or upset conditions.

Based on acid dew point calculation assumptions and results, installing 20-40% additional air heater surface area, thus reducing the flue gas outlet temperature, can provide a significant heat rate improvement. For every 40°F that the air heater outlet temperature is reduced, the increase in combustion air temperature can provide a 1% efficiency improvement. [13] The results of the analysis are summarized in Table 5-7. It is predicted that the station could

[12] Alstom Power Inc., Air Preheater Company, "Average Cold End Temperature (ACET) Guide" published 2/9/07.
[13] Sargent & Lundy LLC, "Coal-fired Power Plant Heat Rate Reduction." SL-009597, January 22, 2009.

benefit from 0.75% CO_2 reduction, on average, if the air heater outlet temperatures were reduced to 250°F. However, this may not accommodate unit operating with all fuels, but could likely be achieved on an annual average basis.

Table 5-7: Potential Heat Rate Improvement

	Actual SO_2 Outlet Concentration	Actual Minimum AH Outlet Temperature	Theoretical Minimum AH Outlet Temperature[1)]	Potential AH Outlet Temperature Reduction	HRI / CO_2 Reduction
	ppm	°F	°F	°F	%
Boiler A - AH Annual Average	37.8	275	250	25	0.6
Boiler B - AH Annual Average	37.1	285	250	35	0.9

Note 1. Theoretical minimum AH temperature based on based on an average back-end temperature of 165°F.

The addition of 20-40% surface area is not expected to be a simple retrofit for the AES Hawaii unit, due to the tight configuration; however, it is technically feasible. The retrofit would include work on the boiler support steel and complete reconfiguration of the current tube bundles. It is suggested that if the air heater outlet temperature is reduced by installing additional surface area, steam coils should be implemented. The air heater modifications are expected to require a 6 month unit outage to complete. The lost generation is assessed as part of the capital cost, along with the penalty that would be incurred based on the 85% annual capacity factor required by the PPA.

5.1.2.4.1.4 Steam Turbine Upgrades

Steam turbine upgrades have become common on turbines that were installed before the 1990s. Starting in the '90s, turbine manufacturers were able to employ more advanced design tools, such as CFD modeling to improve turbine blade shape and packing design. Retrofitting existing turbines with the advanced design has provided significant improvement to efficiency on large units. Depending on the state of an existing steam turbine and the problems experienced, the entire turbine may have to be replaced, apart from the outer casing. Upgrading high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections can result in up to 2-3% increase in gross power generation on larger steam turbine generators. Since much of the initial improvement is due to the degradation of the existing turbine in comparison to its design, only 1-2% net increase in overall power generation would be expected.[14] Units that experience the most benefit from turbine upgrades are typically units that have steam leakage, erosion, or deposition on blades.

On small steam turbines (typically considered to be ≤200 MWg) such as AES Hawaii, upgrades are not typically performed due to the small overall increase in performance compared to the cost of modifications. For AES Hawaii, this is especially true since there are very few reported problems on the steam turbine. AES Hawaii steam turbine HP section is currently operating within 0.3% of its design point and the IP section is operating within 0.1% of the design point. Due to the age and condition that the AES Hawaii turbine is in currently, it does not provide a large source for improvement with a maintenance overhaul. However, it is still a potential option at AES Hawaii to improve unit efficiency by 1-2%, by upgrading the packing and steam path design. Assuming a 2% improvement in heat rate initially, this would correspond to an average improvement of approximately 1.25% for each 6-year maintenance cycle, due to degradation. Since upgrades such as steam turbine overhauls do not maintain the initial improvement over the entire life of the system between maintenance cycles, the 6-year average is estimated and used to approximate the long-term heat rate improvement potential.

To upgrade to the steam turbine at AES Hawaii, it is expected that a two year lead time for delivery after award would be required. As part of this lead time, the unit would have to go into an outage where the steam turbine supplier would disassemble and measure all components of the existing equipment. After this point, 18 months would be required to complete the engineering and manufacturing of all the new blades and rotor. Another long outage, approximately 8 weeks, would be required to disassemble and install the new equipment.

Due to the terms and conditions of the existing PPA between HECO and AES, upgrading a turbine would be very difficult to complete in the outage time allotted. Upgrades to the turbine would only provide the unit with added efficiency, rather than an increase in generation due to the limitation of 180 MWn, as defined by the PPA. Overall, it is expected that a turbine upgrade could provide AES Hawaii with approximately 1.25% efficiency improvement on a long-term average basis, resulting in a 1.25% CO_2 reduction. Therefore, upgrading the steam turbine is a technically feasible CO_2 control option.

[14] Sargent & Lundy LLC. "Coal-fired Power Plant Heat Rate Reduction." SL-009597, January 22, 2009.

5.1.2.4.1.5 Variable Frequency Drive Motors

Variable frequency drive (VFDs) motors are often used on load-following units, where the dispatch is based on demand and can vary significantly throughout the day. VFDs implemented on large fans or pumps, such as ID or booster fans, allow the motors to operate more efficiently at non-design profiles. Rather than fans or pumps operating at a single speed for all flue gas volumetric flow rates, VFDs control motor power consumption at low loads. These motor controls, if implemented on large equipment, like boiler feed pumps, FD and ID fans, circulating water pumps, or slurry pumps, can reduce auxiliary power consumption at lower loads by 30-60%.[15]

VFD motors typically do not provide significant heat rate reduction on base loaded units such as AES Hawaii. However, S&L was able to collect fan curves and determined that based on the current flue gas volumetric flow rate, the fans are larger than what is required for the unit's current fuels fired and power output limited to 180 MWn. This is likely due to the wide range of fuels that the unit could fire, which could result in higher volumetric flow rates. Additionally, the boiler is designed to generate more steam than it is currently producing, due to the restrictions of the PPA. Considering the conservative sizing basis and the continual operation at loads just below maximum, the unit is consistently operating below the optimal efficiency points of large motors. Analysis of the fan curves revealed VFDs have the potential to reduce aux power consumption.

Table 5-8: Fan Aux Power Savings

	Number per Boiler	*Motor Size (hp)*	*Auxiliary Power Savings (kw)*
Secondary Air FD Fan	1	800	100
Induced Draft Fan	1	2500	200

Integrating VFDs on the secondary air FD and ID fans at AES Hawaii (one per boiler), would result in an aux power savings of approximately 600 kW total. This is equivalent to an overall efficiency improvement of 0.3% when operating at the base loaded profile. If the unit maintained its current profile, it is expected that 0.3% CO_2 reduction would be achievable on a long-term basis. Therefore, VFDs on large fans at AES Hawaii are technically feasible CO_2 control option.

15 *id.*

5.1.2.4.1.6 Combination of Heat Rate Improvement Strategies

Heat rate improvement strategies can sometimes be applied together at a facility to achieve higher total heat rate improvement. Of the five applicable strategies at AES Hawaii, most of them can be considered additive. However, the combination of air heater temperature reduction adding pressure drop to the system will have an impact on the achievable improvement due to the VFDs. Therefore, the heat rate improvement of the VFDs is reduced by the same ratio as increased surface area (i.e. 30%), making the overall strategy not completely additive. Therefore, if all five heat rate improvement projects – control system upgrades, sootblowing, air heater outlet temperature reduction, steam turbine upgrade, and VFDs – are implemented, there is the potential for a combined heat rate improvement of approximately 3.1%. All five upgrades would have to be completed in the air heater outage timeframe, which is considered possible, due to the 6 month duration of the air heater upgrade project if selected as an option. Therefore, the heat rate improvement combination strategy is a technically feasible option to reduce CO_2 emissions by up to 3.1% on an average basis.

While there are many combinations incorporating a select few HRI options, and this plan does not explore each individual one, an additional option that is explored is the combination of the two lowest annual cost options. This would provide an opportunity to provide CO_2 reduction at a lower $/ton, than if high cost options (i.e. air heater temperature reduction) were also included. The combination of VFDs and optimized sootblowing would have the potential to reduce CO_2 emissions by approximately 1.0%.

5.1.2.4.2 *Combined Heat and Power*

Combined heat and power (CHP) is another method in which coal-fired power plants can improve overall efficiency. This arrangement includes generating steam and extracting a portion to be used in another process. Since extracting heat energy out of steam is more efficient than recovering power through a turbine, this improves the overall heat rate of a power plant. Typical heat rate calculations that consider only total energy of fuel fired and total MW generated do not apply to this configuration. Since steam is being extracted prior to passing through the turbine, credit has to be applied in another way; otherwise it would appear that the heat rate of CHP facilities is far higher than typical power plants. The following equations compare typical methodologies for calculating heat rates.

$$Heat\ Rate\ \left(\frac{Btu}{kWh}\right) = \frac{Total\ Fuel\ Input\ \left(\frac{Btu}{hr}\right)}{Net\ Power\ Output\ (kW)} \qquad \textit{Equation (1)}$$

$$FCP\ Heat\ Rate\ \left(\frac{Btu}{kWh}\right) = \frac{Total\ Fuel\ Input\ \left(\frac{Btu}{hr}\right) - Fuel\ Chargeable\ to\ Heat\ \left(\frac{Btu}{hr}\right)}{Net\ Power\ Output\ (kW)} \qquad \textit{Equation (2)}$$

By subtracting the amount of fuel that was used to generate the heat provided in the steam supplied to another process, there is a net savings in the numerator, reducing the net heat rate of the facility.

As previously discussed, CHP facilities have a higher efficiency than a typical coal-fired steam turbine alone. AES Hawaii is a CHP facility and supplies 5% of the steam generated to a nearby industrial facility for part of their process. Steam is extracted from the cross-over between the IP and LP turbine sections at a rate of approximately 40,000 lb/hr. If AES Hawaii increased the amount of steam supplied as heat to other processes, the unit heat rate would improve. One potential way to improve the unit heat rate would be to sell more steam to nearby facilities. However, there does not appear to be a market for increased steam sales, therefore this is not an available option for heat rate improvement. In addition, because producing additional steam for sale would require increased firing of Boilers A and B to continue to satisfy the PPA, mass CO_2 emissions would increase even though overall heat rate is improved when accounting for steam sales. Therefore, additional steam production for AES Hawaii is not a technically feasible GHG control option.

5.1.2.4.3 *Reduce Limestone Consumption*

AES Hawaii injects limestone into the CFB boilers for removal of SO_2 and other acid gases. Once injected into the boilers, the heat causes limestone to undergo calcination thus forming the products CaO and CO_2; CaO ultimately reacts with acid gases for formed, and CO_2 is emitted to the atmosphere. The calcination reaction is as follows:

$$CaCO_3 \rightarrow CaO + CO_2$$

Reducing the limestone injection rate would lower the facility's CO_2 emissions. However, the current limestone injection rate at AES Hawaii is optimized to maintain continuous compliance with applicable regulatory and permit requirements. If limestone consumption were reduced for the purpose of controlling GHG emissions, the SO_2 and other acid gas emissions would increase, potential resulting in non-compliance with emissions standards for those pollutants. Therefore, reducing limestone consumption for the purpose of lowering total CO_2 emissions is not a feasible GHG control option.

5.1.2.4.4 *Replace oil-fired limestone dryers with electric dryers.*

Limestone pulverizers are used to crush the limestone prior to injection into Boilers A and B. The facility's limestone pulverizers include oil-fired dryers for reducing the limestone moisture content prior to injection, which emit CO_2 as a result of fuel oil combustion. An option for reducing CO_2 emissions from the limestone pulverizer dryers is to replace oil-fired dryers with electric dryers. While replacing the oil-fired dryers with electric dryers eliminates CO_2 emissions directly from the limestone pulverizers, facility-wide CO_2 emissions would in fact increase because more coal would have to be fired in Boilers A and B to supply the increased auxiliary power requirement. Therefore, replacing the oil-fired limestone dryers with electric dryers is not a feasible GHG control option.

5.1.2.5 Restrictive Operations

AES Hawaii currently operates under a PPA with HECO that requires that AES Hawaii produce and deliver a continuous supply of electricity. Conditions of the current PPA include achieving at least an 85% equivalent availability factor and maintaining the capability to produce and deliver at least 180 MW. If electricity generation were restricted, not only would AES Hawaii potentially be in default of PPA obligations or be subject to liquidated damages, electricity supply to the island would be reduced thus resulting in potential black out conditions. Restrictive operation is not a feasible option for AES Hawaii.

5.1.2.6 Planned Upgrades, Overhaul, or Retirements

As part of the potential GHG control strategies, a station is able to take credit for future planned upgrades, overhauls, or retirement of existing equipment. At present there are no large scale upgrades or overhauls planned which could result in GHG emission reductions due to improved performance. The five year outlook for capital expenditures reflects regular maintenance activities only, mainly due to the fact that, overall, the unit is performing well. AES Hawaii has the extra incentive to properly maintain units because if a major overhaul were required, AES would be in jeopardy of not meeting the availability requirement included in the current PPA with HECO. In addition, routine maintenance and upgrades are made consistently over time to ensure the units maintain their current heat rate. Therefore, due to the lack of planned large upgrades or overhauls, AES Hawaii cannot rely on planned upgrades or overhaul for GHG reductions.

AES Hawaii is currently selling electricity to HECO under a 30-year PPA that expires in 2022. Although AES Hawaii and HECO are currently negotiating an extension of the PPA, HECO has indicated that there is a possibility that the PPA may not renewed. If the PPA with HECO is not renewed, AES Hawaii will likely be forced to retire in 2022. However, considering PPA renewal negotiations are ongoing, AES Hawaii is not committing to 2022 retirement date. Therefore, GHG reductions cannot be relied upon due to planned retirement.

5.1.2.7 Outstanding Regulatory Mandates, Emissions Standards, and Binding Agreements

There are no outstanding regulatory mandates, emissions standards, or binding agreements that will lead to GHG reductions from AES Hawaii.

5.1.2.8 Other GHG Reduction Initiatives

Other than compliance with Act 234 provisions, there are no GHG reduction initiatives currently in place that will lead to GHG reductions from AES Hawaii

5.1.2.9 Technical Feasibility Summary

Table 5-9 summarizes the results of the feasibility evaluation of available control options for AES Hawaii.

Table 5-9: List of Feasible GHG Control Options

GHG Control Category (HAR §11-60.1-204(d)(3))	Feasible Control Options for AES Hawaii
Carbon Capture and Sequestration	None
Fuel switching or co-fired fuels	Co-Firing • Fuel Oil • Biomass
Energy efficiency upgrades	None
Combustion or operational improvements	Heat Rate Improvements: • Control System Updates • Sootblower Improvements • AH Outlet Temperature Improvements • Steam Turbine Upgrades • VFD Motors
Restrictive operations	None
Planned upgrades, overhaul, or retirement of equipment	None
Outstanding regulatory mandates, emissions standards, and binding agreements	None
Other GHG reduction initiatives	None

5.1.3 Step 3: Rank the Technically Feasible GHG Control Options by Effectiveness

The technically feasible GHG options are listed in Table 5-10 in descending order of control effectiveness. In addition to identifying control effectiveness for each technically feasible control option, Table 5-10 also provides control option-specific emissions rates in terms of tons CO_2e per year, lbs CO_2e per kWh-gross, and tons per year CO_2e reduction.

Table 5-10: Rank Technically Feasible GHG Control Option by Effectiveness

GHG Control Option	GHG Control Effectiveness	Expected GHG Emission Rate		Expected Emission Reduction
	% removal	tons CO_2e/yr	lbs CO_2e/kWh-g	tons CO_2e/yr
Pelletized Biomass Co-firing @ 25% Heat Input	16.0%	**1,412,549**	1.708	269,056
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,469,480**	1.777	212,125
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,575,411**	1.905	106,194
Heat Rate Improvement Combination (All Options)	3.1%	**1,629,055**	1.970	52,550
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,646,361**	1.991	35,245
Turbine Upgrade	1.25%	**1,660,585**	2.008	21,020
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,664,789**	2.013	16,816
Air Heater Temperature Reduction	0.75%	**1,668,993**	2.018	12,612
Sootblower Improvements	0.70%	**1,669,834**	2.019	11,771
DCS Upgrade	0.50%	**1,673,197**	2.023	8,408
VFD Motors	0.30%	**1,676,560**	2.028	5,045
Baseline Emissions	--	**1,681,605**	2.034	--

5.1.4 Step 4: Evaluate the Technically Feasible GHG Control Technologies

An evaluation of the economic, environmental and energy impacts of each technically feasible and commercially available GHG emissions control option is provided below.

5.1.4.1 Economic Evaluation

Economic impacts associated with the potentially feasible GHG control systems were evaluated in accordance with guidelines found in EPA's New Source Review (NSR) Workshop Manual (Draft, 1990). For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) baseline emissions are equal to the actual, calculated levels from 2010; (2) post- GHG control option emissions are equal to the baseline control option emissions times the assumed percent reduction associated with each control option.

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on published information available from equipment vendors and equipment costs recently developed for similar projects. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Capital costs were annualized using a capital recovery factor based on an annual interest rate of 8% and equipment life of 6 years. An equipment life of 6 years was used because the current PPA with HECO will expire in 2022, and even though PPA renewal negotiations are ongoing, the possibility exists that the PPA will not be renewed and AES Hawaii will be forced to retire.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (if applicable), byproduct management, and power requirements. The annual O&M costs include both of these fixed and variable O&M components. O&M costs account for actual 2010 unit capacity factors.

Table 5-11 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-12 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix D.

Table 5-11: GHG Control Cost Summary

GHG Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
VFD Motors	$6,095,000	$1,318,000	$134,000	$1,452,000
DCS Upgrades	$8,100,000	$1,752,000	$115,300	$1,867,300
Sootblower Improvements	$2,604,000	$563,000	$42,300	$605,300
Air Heater Temperature Reduction	$96,521,000	$20,879,000	$1,723,600	$22,602,600
Heat Rate Improvement Combination (Low Cost)	$8,700,000	$1,882,000	$175,300	$2,057,300
Turbine Upgrade	$38,598,000	$8,349,000	$4,400	$8,353,400
Fuel Oil Co-firing @ 10% Heat Input	$1,053,000	$228,000	$17,761,500	$17,989,500
Heat Rate Improvement Combination (All Options)	$132,121,000	$28,580,000	$1,852,100	$30,432,100
Fuel Oil Co-firing @ 30% Heat Input	$2,397,600	$519,000	$53,461,800	$53,980,800
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$30,780,000	$6,658,000	$30,464,500	$37,122,500
Pelletized Biomass Co-firing @ 25% Heat Input	$21,060,000	$4,556,000	$29,309,300	$33,865,300

Table 5-12: GHG Emissions Control System Cost Effectiveness

GHG Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons CO_2e/yr	Average Annual Cost Effectiveness $/ton CO_2e removed	Incremental Annual Cost Effectiveness[1] $/ton CO_2e removed
VFD Motors	$1,452,000	5,045	**$288**	--
DCS Upgrades	$1,867,300	8,408	**$222**	$123
Sootblower Improvements	$605,300	11,771	**$51**	--
Air Heater Temperature Reduction	$22,602,600	12,612	**$1,792**	$26,162
Heat Rate Improvement Combination (Low Cost)	$2,057,300	16,816	**$122**	$288
Turbine Upgrade	$8,353,400	21,020	**$397**	$1,498
Fuel Oil Co-firing @ 10% Heat Input	$17,989,500	35,245	**$510**	$677
Heat Rate Improvement Combination (All Options)	$30,432,100	52,550	**$579**	$719
Fuel Oil Co-firing @ 30% Heat Input	$53,980,800	106,194	**$508**	$439
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$37,122,500	212,125	**$175**	$42
Pelletized Biomass Co-firing @ 25%	$33,865,300	269,056	**$126**	$16

Note 1. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual GHG emissions reductions (tpy) between a control option and the next most effective option.

Table 5-12 indicates that the average annual cost effectiveness of the technically feasible GHG control options for AES Hawaii range from $51 per ton (sootblowing) to $1,792 per ton (air heater temperature reduction) CO_2e removed. Equipment costs, energy costs, lost production costs, and annual operating costs (e.g., fuel costs) all have a significant impact on the cost of the GHG control systems.

5.1.4.2 Environmental Impacts

Firing biomass or larger quantities of fuel oil may increase the emissions of hazardous air pollutants (HAP), including acid gases, organics, and HAP metals. For example, the results of recent biomass fuel test burns indicate that HCl emissions will increase if biomass firing is implemented and additional acid gas controls are not installed. Firing biomass or larger quantities of fuel oil would change the fly ash composition and may limit disposal options. In addition, biomass or fuel oil delivery by truck will increase fugitive dust emissions, and delivery by truck or barge will result in emissions of all pollutants, including GHG.

There are no significant collateral environmental issues associated heat rate improvements that would exclude the options from consideration for GHG control.

5.1.4.3 Energy Impacts

Firing biomass will increase the heat rate of the boiler, potentially increasing the amount of fuel required to meet the power generation demand. Otherwise, there are no significant collateral energy impacts associated with the technically feasible co-firing options and heat rate improvements that would exclude the options from consideration for GHG control.

5.1.4.4 Summary of Economic, Environmental, and Energy Impact Analysis

The results of the Step 4 economic, environmental, and energy impact analysis are provided in Table 5-13.

Table 5-13. Summary of Economic, Environmental, and Energy Impact Analysis for GHG Emissions Control Options

GHG Control Option	Average Annual Cost Effectiveness $/ton CO_2e removed	Incremental Annual Cost Effectiveness[1] $/ton CO_2e removed	Environmental Impacts	Energy Impacts
VFD Motors	$288	--	N/A	N/A
DCS Upgrade	$222	$123	N/A	N/A
Sootblower Improvements	$51	--	N/A	N/A
Air Heater Temperature Reduction	$1,792	$26,162	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$122	$288	N/A	N/A
Turbine Upgrade	$397	$1,498	N/A	N/A
Fuel Oil Co-firing @10% Heat Input	$510	$677	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$579	$719	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$508	$439	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$175	$42	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$126	$16	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate

Note 1. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual GHG emissions reductions (tpy) between a control option and the next most effective option.

5.1.5 Step 5: Proposed Control Strategy for GHG Emissions

The evaluation of GHG control options for AES Hawaii has shown that certain heat rate improvements and co-firing options are technically feasible in terms of GHG emissions reductions. An economic evaluation performed for each heat rate improvement option indicates that, based on expected emissions reductions and estimated control costs, the average annual cost effectiveness of the GHG control systems range from $51 per ton (sootblowing improvements) to $1,792 per ton (air heater temperature reduction) GHG removed. Fuel oil and biomass co-firing may also be technically feasible GHG reduction options, however, the average cost effectiveness of these options range from $126 per ton to $510 per ton. The environmental impacts of co-firing biomass or fuel oil include: potential increases in HAP emissions that would have to be mitigated, changes in fly ash composition that may impact ash disposal options, and emissions related to fuel delivery trucks. Energy impacts associated with biomass co-firing are related to reduced boiler efficiency, due to reduced heating value and higher fuel moisture content compared to coal.

5.1.5.1 Cost Effectiveness Threshold

EPA and DOH have not defined a cost threshold at which GHG control options for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically based on previous determinations for similar sources, and are set at the discretion of regulating agencies on a project-specific basis. Prior to 2011, GHG emissions were not regulated under EPA's NSR permitting program. Most GHG BACT evaluations performed to date for power generating facilities have been prepared for new gas fired simple cycle or combined cycle combustion turbines, and those evaluations generally conclude that CCS is not technically feasible, or if feasible, cost prohibitive. In an attempt to identify a reasonable GHG cost effectiveness threshold at which GHG control options are cost effective, S&L performed a review of publically available documents, including GHG BACT determinations and EPA background documents.

A GHG BACT analysis was performed in 2009 for the Hyperion Energy Center located in South Dakota. That project proposed to install a petroleum coke-fired integrated gasification combined cycle facility. The Hyperion BACT analysis concluded that CCS was a technically feasible control option, especially considering the facility's proximity to a nearby oil field that could utilize captured CO_2 for enhanced oil recovery. The analysis identified CCS system cost effectiveness values ranging from $33 per ton to $91 per ton, but concluded that CCS was not a cost effective CO_2 control option based on the market value of CO_2 allowances (at the time ranging from $1.80 per ton to $12 per ton). Recent market prices of CO_2 allowances range from approximately $5.65 per ton (Regional

Greenhouse Gas Initiative) to \$11.50 per ton (California carbon market). Based on the Hyperion Energy BACT determination and the market price of CO_2 allowances in existing regional trading programs, it was concluded that GHG control options with cost effectiveness values less than \$11.50 per ton GHG removed could be considered cost effective.

In addition to reviewing current market prices, cost estimates prepared by EPA for the recently published the Clean Power Plan (CPP) were also reviewed. The CPP regulates CO_2 emissions from existing coal and natural gas-fired power plants in the continental United States. EPA established state-specific CO_2 emissions goals based on an evaluation of the following building blocks: Building Block 1 – efficiency improvements at affected coal-fired units; Building Block 2 – shifting power generation from coal-fired units to gas-fired units; Building Block 3 – shifting generation to renewable sources. For Building Block 1, EPA concluded that the assumed CO_2 reductions associated with energy efficiency improvements at existing coal-fired facilities are reasonable at a cost of \$23 per ton.[16] Notwithstanding ongoing court challenges to the CPP, for the purpose of this evaluation it was concluded that GHG control options with cost effectiveness values below \$23 per ton GHG removed could be considered cost effective, while control options with effectiveness values greater than \$23 per ton GHG removed are not cost effective. Because the CPP Building Block 1 cost is greater than recent market prices of carbon, a cost effectiveness value of \$23 per ton GHG removed is considered a conservatively high threshold for evaluating control technology cost effectiveness.

5.1.5.2 Proposed Control Strategy.

Based on the range of costs identified for AES Hawaii GHG control options, and an assumed cost effectiveness threshold of \$23 per ton GHG removed, all of the technically feasible GHG emissions improvements identified for AES Hawaii are considered cost prohibitive. AES Hawaii is proposing a 2020 GHG emissions control strategy that is based on limiting facility-wide GHG emissions to 2010 baseline levels. AES Hawaii will achieve the proposed control strategy by continuing to implement the facility's existing comprehensive inspection and preventive maintenance program designed to address boiler operation, maintenance, and efficiency.

[16] 80 FR 64749, col. 1.

5.2 PROPOSED 2020 FACILITY-WIDE GHG EMISSIONS CAP

A GHG emissions control assessment performed for the AES Hawaii facility identified three control option categories that are considered technically feasible: (1) heat rate improvements; (2) fuel oil co-firing; and (3) biomass co-firing. An economic evaluation performed for each option indicates that, based on expected GHG emissions reductions and estimated annual costs, the average cost effectiveness ranges from approximately $51 per ton (sootblowing improvements) to $1,792 per ton (air heater temperature reduction) GHG removed. For the purpose of this evaluation, it has been assumed that GHG control options having cost effectiveness values greater than $23 per ton GHG removed are not cost effective; therefore none of the available and technically feasible GHG control options for AES Hawaii are considered to be cost effective.

AES Hawaii is proposing a 2020 facility-wide GHG emissions cap that is based on limiting GHG emissions to 2010 baseline levels. AES Hawaii plans to meet the 2020 facility-wide GHG emissions cap by continuing to implement a comprehensive inspection and preventative maintenance program that addresses boiler operation, maintenance and efficiency. The proposed 2020 facility-wide GHG emissions cap and compliance demonstration method are identified in Table 5-14.

Table 5-14. 2020 Facility-Wide GHG Emissions Cap

Pollutant	AES Hawaii Facility-Wide Emissions Cap	Method for Controlled GHG Emissions	Compliance Demonstration Methodology
CO_2e	1,681,605 tons/yr	Comprehensive inspection and preventive maintenance program designed to address boiler operation, maintenance, and efficiency	CO_2 CEMS (Boilers A and B) GHG emissions calculations using annual fuel consumption rates and limestone consumption rates, and representative emissions factors

APPENDIX A. HAR §11-60.1 SUBCHAPTER 11: GREENHOUSE GAS EMISSIONS

(1) waive the person's right to a contested case hearing pursuant to chapter 91, HRS;
(2) waive any challenge to the citation;
(3) pay the penalty assessed;
(4) correct the violation; and
(5) enter into the settlement agreement.

(c) The settlement agreement is not effective until it is signed by both the person to whom the citation was issued and by the director. Approval by the director shall be at the director's sole discretion.

(d) The director may withdraw the citation if the person to whom it is issued declines to accept the director's offer to settle or fails to satisfactorily meet any of the conditions set forth in §11-60.1-193(b), in which case the director may bring a formal administrative action under HRS, §342B-42 and pursue any remedies available under this chapter, HRS, chapter 342B, or any other law. [Eff and comp 9/15/01; comp 11/14/03; comp 1/13/12; comp 6/30/14] (Auth: HRS §342B-42)

§11-60.1-194 Form of citation. A field citation issued pursuant to this section shall be in the form prescribed by the department. [Eff and comp 9/15/01; comp 11/14/03; comp 1/13/12; comp 6/30/14] (Auth: HRS §342B-42)

SUBCHAPTER 11

GREENHOUSE GAS EMISSIONS

§11-60.1-201 Purpose. The purpose of this subchapter is to further implement the goals of Act 234, 2007 Hawaii Session Laws. A statewide greenhouse gas emission (GHG) limit, to be achieved by 2020, is set to equal or below the 1990 statewide greenhouse gas emission levels. Greenhouse gas emissions from airplanes shall not be included. [Eff and comp 6/30/14] (Auth: HRS §§342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

§11-60.1-202 Definitions. As used in this subchapter:

"Carbon sink or carbon dioxide sink" means a carbon reservoir that removes a greenhouse gas or a precursor of a greenhouse gas or aerosol from the atmosphere, and is the opposite of a carbon source. The main sinks are the oceans and growing vegetation that absorb CO_2.

"Facility-wide GHG emissions cap" means a permit emissions limitation, applicable to a covered source, limiting the entire source's annual non-biogenic greenhouse gas, and biogenic nitrous oxide and methane emissions. A facility-wide GHG emissions cap may also be defined in multiple covered source permits to identify partnering facilities with an approved combined GHG emissions cap as described in subparagraph 11-60.1-204(d)(6)(A).

"Municipal waste combustion operations" means a permitted covered source that combusts solid, liquid, or gasified household, commercial/retail, and/or institutional waste.

"On-the-Book" means control measures or operational practices affecting GHG emissions that the owner or operator of a facility plans, or is undertaking to implement because of regulatory or legal obligations; or as demonstrated through financial and resource commitments. Examples include required controls or practices mandated by a state or federal law; or budgeted and contracted/funded projects or resources.

"Permitted covered source" means a stationary source or facility issued or required to hold a covered source permit pursuant to this chapter, and has begun construction or operation by the effective date of this subchapter. [Eff and comp 6/30/14] (Auth: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

§11-60.1-203 Greenhouse gas emission limit. The statewide GHG emission limit to be achieved by 2020, is equal to or below 13.66 million metric tons (or 15.06 million tons) per year of CO_2e, based on Hawaii's 1990 GHG emission estimates prepared under Act 234, 2007 Hawaii Session Laws. The GHG limit excludes aviation and international bunker fuel emissions, and includes carbon sinks. The director may update the numerical GHG emission limit should improved methodologies and data become available for estimating emissions. The limit serves as an indicator to measure progress of the state's GHG reduction measures and to determine the achievement and maintenance of the state's GHG limit by 2020. [Eff and comp 6/30/14] (Auth: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

§11-60.1-204 Greenhouse gas emission reduction plan. (a) This section applies to an owner or operator of a permitted covered source, except for municipal waste combustion operations, with the potential to emit GHG emissions (biogenic plus non-biogenic) equal to or above 100,000 tons per year CO_2e. Each owner or operator of an affected source shall submit a GHG emission reduction plan for the director's approval within twelve (12) months of the effective date of this section. An owner or operator may submit a written request for an extension 30 days prior to the deadline.

(b) The GHG emission reduction plan will be used to evaluate and establish an annual facility-wide GHG emissions cap for the affected source in support of achieving and maintaining the statewide GHG limit. The approved facility-wide GHG emissions cap and the associated provisions will be made a part of the covered source permit, and may be revised through the permit process to respond to new rules, updated technology, GHG reduction initiatives, and any other circumstances deemed necessary by the director to facilitate the state's GHG limit.

(c) Unless substantiated by the owner or operator of an affected source and approved by the director to be unattainable pursuant to the GHG control assessment described in subsection 11-60.1-204(d), each GHG emission reduction plan shall establish a minimum facility-wide GHG emissions cap in tons per year CO_2e, to be achieved by 2020 and maintained thereafter. The minimum facility-wide GHG emissions cap shall be sixteen percent (16%) below the facility's total baseline GHG emission levels less biogenic CO_2 emissions, as follows:

$$\text{Facility-wide cap (tpy } CO_2e) = (1-0.16) \times \left| \begin{array}{lcl} \text{Facility} & & \text{Facility} \\ \text{Total} & - & \text{Baseline} \\ \text{Baseline} & & \text{Biogenic} \\ \text{Emissions} & & CO_2 \text{ Emissions} \end{array} \right| \text{(tpy } CO_2e)$$

Where:

Facility Total Baseline Emissions (tpy CO_2e) =
Baseline[Biogenic CO_2 + Non-Biogenic GHG Emissions]

Calendar year 2010 shall be used as the baseline year, unless the owner or operator can provide records for the director's approval demonstrating another year or an average of other years to be more representative of normal operations. Newly permitted sources without an operating history, shall estimate normal operations for the director's approval in establishing the facility-wide GHG emissions cap.

(d) The GHG emission reduction plan required of affected sources shall at a minimum include:

(1) The facility-wide baseline annual emission rate (tpy CO_2e). Calendar year 2010 annual emissions shall be used as the baseline emissions to calculate the required facility-wide GHG emissions cap, unless another baseline year or period is approved by the director. Baseline emissions shall be determined in accordance with section 11-60.1-115, separated between biogenic and non-biogenic emissions, and exclude all emissions of noncompliance with an applicable requirement or permit limit. The owner or operator shall include the data and calculations used to determine the baseline emissions. If calendar year 2010 is deemed unrepresentative of normal operations, then the owner or operator may propose an alternate baseline annual emission rate for the director's approval, as follows:

(A) The owner or operator shall clearly document why calendar year 2010 is not representative of normal operations and why the proposed alternate year or period is more suitable based on trends, existing equipment and controls, scheduled maintenance, operational practices, and any other relevant information. Acceptable methods for determining alternate facility-wide baseline annual emissions include:

(i) the facility-wide GHG emissions (less biogenic CO_2) based on the most recent representative year during the five-year period ending 2010;

(ii) average facility-wide GHG emissions(less biogenic CO_2) over any consecutive two-year period during the five-year period ending in 2010;

(iii) average facility-wide GHG emissions (less biogenic CO_2) for the five-year period ending in 2010; or

(iv) comparable methods as approved by the director. The director will not consider the use of periods greater than five years from 2010, except for extreme cases such as where an affected source may not have been fully operational for an extended period of time.

(B) For newly permitted covered sources without a 2010 operating history, the owner or operator shall make the best estimate of normal operations based on contract agreements, available operational records, required scheduled maintenance, market forecast, or any other information for projecting the affected source emissions. Potential emissions shall not be used, unless the owner or operator can clearly demonstrate that the facility will be continually operating at the maximum capacity for each and every year.

The owner or operator shall provide all supporting documentation for the proposed alternate baseline emission rate. The director, based on available information, may reject and modify the baseline emission rate in establishing the final facility-wide GHG emissions cap.

(2) The 2020 facility-wide GHG emissions cap. Determine the facility-wide GHG emissions cap in accordance with subsection(c), using calendar year 2010 or the proposed GHG baseline emission rate determined by paragraph (1) above. If the required

emissions cap requiring a sixteen percent (16%) emission reduction from baseline year emissions is deemed unattainable, the owner or operator shall provide, as part of the reduction plan:

(A) The justification and supporting documentation of why the required emissions cap cannot be met; and

(B) A proposal, for the director's approval, of an alternate emissions cap resulting in the maximum achievable GHG reductions.

In determining whether or not the required GHG emissions cap is attainable, the owner or operator of an affected source shall first conduct the GHG control assessment described in paragraphs (3) to (5). Available EPA guidelines for GHG Best Available Control Technology analysis, and GHG control measures by source type shall be used as applicable for this assessment.

(3) Available Control Measures. Identify all available control measures with potential application for each source type, and all on-the-book control measures the facility is committed or will be required to implement affecting GHG emissions. At a minimum, the following shall be considered as applicable:

(A) Available technologies for direct GHG capture and control;

(B) Fuel switching or co-fired fuels;

(C) Energy efficiency upgrades;

(D) Combustion or operational improvements;

(E) Restrictive operations;

(F) Planned upgrades, overhaul, or retirement of equipment;

(G) Outstanding regulatory mandates, emission standards, and binding agreements; and

(H) Other GHG reduction initiatives that may affect the facility's GHG emissions. Unless the owner or operator of the source has direct ownership or legal control over a GHG reduction initiative, that initiative cannot be relied upon as a proposed control strategy. Identification of GHG reduction initiatives, whether or not the owner or operator has ownership or legal control, will serve to highlight their potential importance for reducing GHG emissions in the state. The owner or operator of an affected source will only benefit from a GHG initiative, if the initiative reduces or helps to reduce and maintain the source's GHG emissions below its permitted facility-wide GHG emissions cap.

(4) The Technically Feasible Measures. For any new control measure identified for the facility, eliminate all technically infeasible options based on physical, chemical, or engineering principles that would preclude the successful operation of the control with the applicable emission unit or source. Document the basis of elimination, and generate the list of technically feasible control options for further evaluation. All committed and required on-the-book measures shall remain on the list.

(5) Control Effectiveness and Cost Evaluation. List the technically feasible control options and identify the following for each control measure as applicable. All cost data shall be provided in present dollars.

(A) Control effectiveness (percent pollutant removed);

(B) Expected emission rate (tons per year CO_2e, pounds CO_2e/kilowatt-hour);

(C) Expected emission reduction (tons per year CO_2e);

(D) Energy impacts (BTU, kilowatt-hour);

(E) Environmental impacts (other media and the emissions of other regulated air pollutants);

(F) Any secondary emissions or impacts resulting from the production or acquisition of the control measure; and

(G) Economic impact (cost effectiveness: annualized control cost, dollar/megawatt-hr, dollar/ton CO_2e removed, and incremental cost effectiveness between the control and status quo).

For committed or required on-the-books control measures and any other GHG control initiatives, identify at a minimum, items (A) through (C) above. Considering the energy, environmental, and economic impact, determine the GHG control or suite of controls found to be feasible in achieving the maximum degree of GHG reductions for the facility. Determine whether the required GHG emissions cap, pursuant to subsection (c) will be met. If an alternate cap must be proposed for approval, declare the proposed percentage GHG reduction and the alternate GHG reduction cap. Provide the justification and associated support information (e.g., references, assumptions, vendor quotes, sample calculations, etc.) to substantiate the control analysis and alternate GHG emissions cap.

(6) The proposed Control Strategy. Present the listing of control measures to be used for implementation in meeting the required or proposed alternate 2020 facility-wide GHG emissions cap. Include discussion of the control effectiveness, control implementation schedule, and the overall expected GHG CO_2e emission reductions (tpy) for the entire facility. Owners or operators shall also consider the following:

(A) Affected sources may propose to combine their facility-wide GHG emissions caps to leverage emission reductions among partnering facilities in meeting the combined GHG emissions caps. If approved by the director, each partnering facility will be responsible for complying with its own adjusted GHG facility-wide emissions cap.

(B) Except for fee assessments and determining applicability to this section, biogenic CO_2 emissions will not be included when determining compliance with the facility-wide emissions cap until further guidance can be provided by EPA, or the director, through rulemaking.

(C) The approved facility-wide GHG emissions cap and the associated monitoring, recordkeeping, and reporting provisions will be made a part of the covered source permit, enforceable by the director.

(e) Failure to submit an adequate GHG emission reduction plan, or failure to submit relevant facts or correct information upon becoming aware of such failure, constitutes a violation of this chapter. The owner or operator of an affected source has the same duty to certify the GHG emission reduction plan in accordance with section 11-60.1-4, and supplement or correct the GHG emission reduction plan, similar to the provisions in section 11-60.1-84 for covered source permit applications. During the processing of a GHG emission reduction plan, if the director determines that a re-submittal of the plan is required, or submittal of additional information is necessary to evaluate or take final action on the plan, the director may make the request in writing and set a reasonable deadline for the response.

(f) If the owner or operator of an affected source fails to submit an adequate GHG emission reduction plan, or if a facility-wide GHG emissions cap cannot be mutually agreed upon, the director reserves the right to establish, and incorporate into the applicable covered source permit, a facility-wide GHG emissions cap as required or the lowest cap deemed achievable by the affected source based on the intent of this subchapter.

(g) Once a facility-wide GHG emissions cap is established and placed into the covered source permit, the GHG emission reduction plan shall become a part of the covered source permit application process for renewals and any required modifications pursuant to subchapter 5. With each subsequent GHG emission reduction plan submittal, the owner or operator of the affected source shall report:

(1) The GHG emission reduction status;
(2) Factors contributing to the emission changes;
(3) Any control measure updates; and
(4) Any new developments or changes that would affect the basis of the facility-wide GHG emissions cap.

(h) The facility-wide GHG emissions cap may be re-evaluated and revised by the director if any of the following events or circumstances exists:

(1) Consideration for new rules, updated technology, implementation of GHG reduction initiatives, significant changes with renewable energy cost and supply, and any other measures deemed necessary by the director to facilitate the state's GHG limit;
(2) The basis for establishing the facility-wide GHG emissions cap is found to be incorrect;
(3) The methodology for calculating GHG emissions is updated or modified;
(4) Renewable energy producers cease operations or fail to meet contractual obligations with the affected source, and there are no other reasonable alternatives; or
(5) Reasonably unforeseen events beyond the control of the owner or operator of an affected source, resulting in long-term or

temporary emission changes, whereby the maintenance of the GHG emissions cap would be detrimental to the health and welfare of the public.

Any revision to a facility-wide GHG emissions cap is considered a significant modification subject to the application and review requirements of section 11-60.1-104. The owner or operator of an affected source seeking a GHG emissions cap change has the burden of proof to substantiate any requested change for the director's approval. Upon approving any GHG emissions cap revision, the director may impose additional emission limits or requirements on the affected source, or limit the time-frame allowed for the revised GHG emissions cap.

(i) Municipal solid waste landfills required by 40 CFR Part 60, Subpart Cc or 40 CFR Part 60, Subpart WWW to use gas collection and control systems are conditionally exempt from the GHG emission reduction requirements of Subsection 11-60.1-204(c).

(j) Should the permitted facility-wide GHG emissions cap not be met by January 1, 2020 and annually maintained thereafter, the owner or operator of the covered source shall be subject to enforcement action for each year after 2019 that the facility-wide cap is not met. Compliance with the facility-wide cap shall be determined at the end of each calendar year, or January 1 of the following year, starting with the end of 2019 or January 1, 2020. Each CO_2e ton over the cap shall constitute a separate offense and violation.

(k) The director shall conduct an evaluation in 2016, and annually thereafter, to determine the progress of achieving and if applicable, ongoing maintenance of the statewide GHG emissions limit specified in HRS, Chapter 342B-71 and section 11-60.1-203. The evaluation of the statewide GHG emission limit shall be conducted in a manner consistent with the procedures used to prepare the 1990 emission estimates under Act 234, 2007 Hawaii Session Laws. The director shall produce and make public annual progress reports listing GHG emissions levels for each affected facility and the statewide progress relative

to the statewide GHG emission limit. If the director determines that statewide GHG emission limit is met prior to 2020 and GHG emission projections indicate ongoing maintenance of the limit, the requirements of this section shall no longer be applicable to the affected facilities. Prior to finalizing any determination that the statewide GHG emission limit has been met, the director shall provide for public notice and an opportunity for public comment in accordance with the requirements specified in section 11-60.1-205. Upon achieving the statewide GHG emission limit, the director may revise or adopt additional rules to ensure the ongoing maintenance of the statewide GHG emission limit.
[Eff and comp 6/30/14] (Auth: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

§11-60.1-205 Public participation. (a) The director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on all draft GHG emission reduction plans from §11-60.1-204. Any person requesting a public hearing shall do so during the public comment period. Any request from a person for a public hearing shall indicate the interest of the person filing the request and the reasons why a public hearing is warranted.

(b) Procedures for public notice, public comment periods, and public hearings shall be as follows:

(1) The director shall make available for public inspection in at least one location in the county affected by the proposed action, or in which the source is or would be located:
   (A) Information on the subject matter;
   (B) Information submitted by the proposing party, except for that determined to be confidential pursuant to section 11-60.1-14;

(C) The department's analysis and proposed action; and
(D) Other information and documents determined to be appropriate by the department;

(2) Notification of a public hearing shall be given at least thirty days in advance of the hearing date;

(3) A public comment period shall be no less than thirty days following the date of the public notice, during which time interested persons may submit to the department written comments on:
(A) The subject matter;
(B) The greenhouse gas emission reduction plan;
(C) The department's analysis;
(D) The proposed actions; and
(E) Other considerations as determined to be appropriate by the department;

(4) Notification of a public comment period or a public hearing shall be made:
(A) By publication in a newspaper which is printed and issued at least twice weekly in the county affected by the proposed action, or in which the source is or would be located;
(B) To persons on a mailing list developed by the director, including those who request in writing to be on the list; and
(C) If necessary by other means to assure adequate notice to the affected public;

(5) Notice of public comment and public hearing shall identify:
(A) The affected facility;
(B) The name and address of the proposing party;
(C) The name and address of the agency of the department reviewing the plan;
(D) The activity or activities involved in the plan, including, but not limited

to, whether the proposing party proposes:
(i) an alternate baseline year;
(ii) an alternate facility-wide GHG emissions cap;
(iii) a control strategy involving partnering with one or more facilities.

(E) The emissions change involved in the plan;

(F) The name, address, and telephone number of a person from whom interested persons may obtain additional information, including copies of the draft plan, all relevant supporting materials, and all other materials available to the department that are relevant to the decision, except for information that is determined to be confidential, including information determined to be confidential pursuant to section 11-60.1-14;

(G) A brief description of the comment procedures;

(H) The time and place of any hearing that may be held, including a statement of procedures to request a hearing if one has not already been scheduled; and

(I) The availability of the information listed in paragraph (1), and the location and times the information will be available for inspection; and

(6) The director shall maintain a record of the commenters and the issues raised during the public participation process and shall provide this information to the Administrator upon request." [Eff and comp 6/30/14] Auth: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

§11-60.1-206 Public petitions. (a) The applicant and any person who participated in the public comment or hearing process and objects to the grant or denial of a draft GHG emission reduction plan, may petition the department for a contested case hearing by submitting a written request to the director.

(b) The petition shall be based solely upon objections to the draft GHG emission reduction plan, that were raised with reasonable specificity during the public participation process, unless the petitioner demonstrates that it was impracticable to raise such objections; for example, the grounds for such objections arose after the public participation process.

(c) Any petitioner shall file a petition for a contested case hearing within ninety days of the date of the department's approval or disapproval of the proposed draft GHG emission reduction plan.

(d) Notwithstanding the provisions of subsection (b), if based solely on objections which were impracticable to raise during the public participation process, a petition for a contested case hearing may be filed up to ninety days after the objections could be reasonably raised.

(e) Except as provided in subsection (f), any draft GHG emission reduction plan that has been issued shall not be invalidated by a petition for a contested case hearing. If a draft GHG emission reduction plan is issued by the director, the owner or operator of the source shall not be in violation of the requirement to have submitted a timely and complete application.

(f) The effective date of draft GHG emission reduction plan shall be as specified for permits in 40 CFR Part 124.15 as it existed on November 19, 2013.

(g) Any person may petition for a contested case hearing for the director's failure to take final action on an application for draft GHG emission reduction plan, within the time required for permits by this chapter. Such petition shall be submitted in writing and may be filed any time before the director issues a proposed draft GHG emission reduction.

(h) Any person aggrieved by a final administrative decision and order, including the denial of any contested case hearing, may petition for judicial review pursuant to section 91-14, HRS. A petition for judicial review shall be filed no later than thirty days after service of the certified copy of the final administrative decision and order." [Eff and comp 6/30/14] Auth: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416) (Imp: HRS §§ 342B-3, 342B-12, 342B-71, 342B-72, 342B-73; 42 U.S.C. §§7407, 7416)

Amendments to and compilation of chapter 60.1, title 11, Hawaii Administrative Rules, on the Summary Page dated **June 19, 2014** were adopted on **June 19, 2014** following public hearings held on November 20, 28, 29 and 30, 2012, after public notice was given in the *Honolulu Star Advertiser, The Garden Island, The Maui News, West Hawaii Today*, and *Hawaii Tribune Herald*, on October 19, 2012.

The rules shall take effect ten days after filing with the Office of the Lieutenant Governor.

(signed)
LINDA ROSEN, M.D., M.P.H.
Director of Health

(signed)
NEIL ABERCROMBIE
Governor
State of Hawaii

Dated: 6/20/14

Filed

APPROVED AS TO FORM:

(signed)
WILLIAM F. COOPER
Deputy Attorney General

APPENDIX B. CALENDAR YEAR 2010 ANNUAL BASELINE EMISSIONS CALCULATIONS

Appendix B

Table 1. 2010 Facility-Wide Baseline GHG Emissions

Emission Source	Material	2010 Total Material Consumption[1]		Average Heating Value[1]		Emission Factors[2,3]					GHG Emissions						
						CO_2		NO_2	CH_4	CO_2e[4]	CO_2[9]		N_2O		CH_4		Total CO_2e[4]
											Non-Biogenic	Biogenic	as N_2O	as CO_2e	as N_2O	as CO_2e	
		tons/yr	gal/yr	Btu/lb	Btu/gal	lb/MMBtu	lb/lb	lb/MMBtu	lb/MMBtu	lb/MMBtu	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
Boilers A and B (total)	Coal[5]	743,632		10,571				3.5E-03	2.4E-02		1,645,215		27.7	8,596	190.6	4,003	1,657,813.8
	Fuel Oil[5]		74,490		138,000	163.1		1.3E-03	6.6E-03	163.6	838.1		0.0068	2.11	0.034	0.71	840.9
	TDF[6]	0		14,000		189.5		9.3E-03	7.1E-02	193.9	0		0	0	0	0	0
	Spent Activated Carbon[7]	751		15,000		225.8		3.5E-03	2.4E-02	227.4	2,543.3		0.04	12.32	0.27	5.74	2,561.4
	Spec. Used Oil[8]		609,090		138,000	163.1		1.3E-03	6.6E-03	163.7	6,856.3		0.056	17.2	0.28	5.84	6,879.4
	Limestone	28,742					0.440				12,686						12,685.8
	Biomass	0				0						0					
	Total, Boilers A and B										1,668,138	0	28	8,627	191	4,015	1,680,781
Limestone Dryers	Fuel Oil		73,027		138,000	163.1		1.3E-03	6.6E-03	163.6	822		0.0	2.07	0.0	0.70	824
Facility-Wide Total											1,668,960	0	28	8,629	191	4,016	1,681,605

Note 1. Annual consumption rates and heating values provided by AES.

Note 2. Emission factors for all materials except limestone obtain from Table C-1 to Subpart C of Part 98.

Note 3. Limestone emission factor based on conversion of limestone (as 100% $CaCO_3$) to CO_2.

Note 4. CO_2e emissions calculated based on sum of CO_2, NO_2, and CH_4 emissions, accounting for GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, NO_2 = 310, CH_4 = 21).

Note 5. Coal feeder flows and #2 fuel oil start-up burner flows are recorded in the Daily Plant database. A monthly fuel report, called the Fuel Status Report, for inventory balances is also output from the database that includes inventory adjustments and all fuel beginning and ending balances.

Note 6. TDF delivery system has a variable speed drive and weigh scale for delivery to the coal silos. Since the TDF is delivered to the boilers via the same gravimetric feeders that deliver the coal, this is corrected for in the final coal feed values.

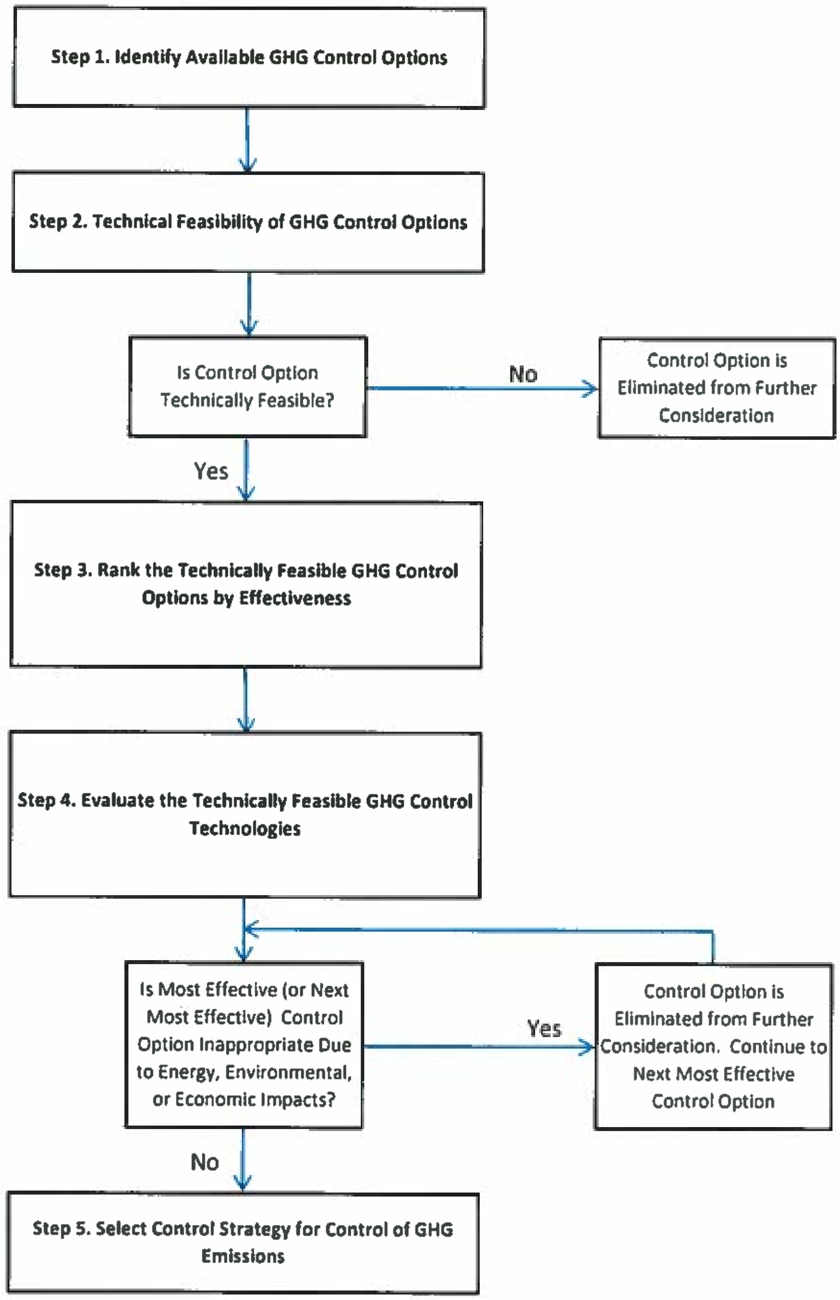
Note 7. Activated carbon usage is based on actual delivery volumes.

Note 8. The spec. used oil non-resetting flow meter is read each night and the value is manually entered into a database.

Note 9. CO_2 Emissions from Coal were calculated using Tier 3 methodology.

APPENDIX C. GHG CONTROL EVALUATION PROCEDURE FLOW CHART

GHG Control Control Evaluation Procedure Flow Chart



APPENDIX D. DETAILED COST ESTIMATES

GHG Cost Evaluation
CO2 Control

AES Hawaii Boilers A and B
CO2 CONTROL SUMMARY

Table 1. AES Hawaii Operating Parameters

Pollutant:	CO2	Unit	Notes
Hourly Gross Generation	200	MWh-gross	
Annual Gross Generation	1,653,792	MWh-gross	Based on 2010 operation
Hourly Heat Input	2,150	MMBtu/hr	AES Hawaii Combined Source Permit
Average Capcity Factor	94%	%	Based on maximum gross generation compared to the 2010 annual generation.
Annual Heat Input	15,837,251	MMBtu/yr	Based on 2010 operation

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb CO_2e/kWh-g)	Expected Emissions Reduction (ton/year)
Pelletized Biomass Co-firing - 25%	16.0%	1,412,549	1.708	269,056
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	1,469,480	1.777	212,125
Fuel Oil Co-firing -30% Heat Input	6.3%	1,575,411	1.905	106,194
Heat Rate Improvement Combination (All Options)	3.1%	1,629,055	1.970	52,550
Fuel Oil Co-firing -10% Heat Input	2.1%	1,646,361	1.991	35,245
Turbine Upgrade	1.25%	1,660,585	2.008	21,020
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	1,664,789	2.013	16,816
Air Heater Temperature Reduction	0.75%	1,668,993	2.018	12,612
Sootblower Improvements	0.70%	1,669,834	2.019	11,771
DCS Upgrade	0.50%	1,673,197	2.023	8,408
VFD Motors	0.30%	1,676,560	2.028	5,045
Baseline Emissions	0	**1,681,605**	2.034	0

Table 3. Cost Effectiveness - 6-Year Remaining Useful Life of Equipement

Control Technology	Emissions (tpy)	Tons of CO2 Removed (tpy)	Total Capital Requirement ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline Emissions	1,681,605	-	--	--	--	--		
VFD Motors	1,676,560	5,045	$6,095,000	$1,318,000	$134,000	$1,452,000	$288	
DCS Upgrade	1,673,197	8,408	$8,100,000	$1,752,000	$115,300	$1,867,300	$222	$123
Sootblower Improvements	1,669,834	11,771	$2,604,000	$563,000	$42,300	$605,300	$51	
Air Heater Temperature Reduction	1,668,993	12,612	$96,521,000	$20,879,000	$1,723,600	$22,602,600	$1,792	$26,162
Heat Rate Improvement Combination (Lowest Cost Options)	1,664,789	16,816	$8,700,000	$1,882,000	$175,300	$2,057,300	$122	$288
Turbine Upgrade	1,660,585	21,020	$38,598,000	$8,349,000	$4,400	$8,353,400	$397	$1,498
Fuel Oil Co-firing -10% Heat Input	1,646,361	35,245	$1,053,000	$228,000	$17,761,500	$17,989,500	$510	$677
Heat Rate Improvement Combination (All Options)	1,629,055	52,550	$132,121,000	$28,580,000	$1,852,100	$30,432,100	$579	$719
Fuel Oil Co-firing -30% Heat Input	1,575,411	106,194	$2,397,600	$519,000	$53,461,800	$53,980,800	$508	$439
Local Eucalyptus Biomass Co-firing - 150,000 TPY	1,469,480	212,125	$30,780,000	$6,658,000	$30,464,500	$37,122,500	$175	$42
Pelletized Biomass Co-firing - 25%	1,412,549	269,056	$21,060,000	$4,556,000	$29,309,300	$33,865,300	$126	$16

GHG Cost Evaluation
Heat Rate Improvements

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - VFDs

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,681,605
Post HRI CO2 Emissions (tpy)	1,676,560
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$3,762,000	VFDs on ID and FD fans (one each boiler) based on a cost of $570/hp
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$3,762,000	
Direct Installation Costs		
Installation	$1,129,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	**$4,891,000**	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties.
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	**$0**	
Contingency	$752,000	20% of equipment costs
Hawaii Cost Adder	$451,600	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	**$6,095,000**	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6-year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	1,318,000	based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$175,594	Coal cost and fuel oil costs based on 2015 average as delivered: $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton.
Disposal Cost Differential	-$8,000	Based on $57/ton
Auxiliary Power Cost Differential	$0	
Total Variable O&M Costs	-$183,594	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects.
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$97,800	Based on 2% of the capital cost.
Maintenance Labor	$97,800	Based on 2% of the capital cost.
Total Fixed O&M Cost	$195,600	
Indirect Operating Cost		
Property Taxes	$61,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$61,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$122,000	
Total Annual Operating Cost	**$134,000**	

6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$1,318,000**	
Annual Operating Cost	**$134,000**	
Total Annual Cost	**$1,452,000**	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - DCS UPGRADE

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,681,605
Post HRI CO2 Emissions (tpy)	1,673,197
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$5,000,000	Based on system upgrade cost of $5,000,000, including Boilers A & B.
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$5,000,000	
Direct Installation Costs		
Installation	$1,500,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	$6,500,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage.
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties.
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	
Contingency	$1,000,000	20% of equipment costs.
Hawaii Cost Adder	$600,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$8,100,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / ((1+i)^n - 1)$	0.2163	6 year life of equipment (years) @ 8% interest.
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	1,752,000	based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$292,656	Coal cost and fuel oil costs based on 2015 average as delivered: $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton.
Disposal Cost Differential	-$14,000	Based on $57/ton.
Auxiliary Power Cost Differential	$0	
Total Variable O&M Costs	-$306,656	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects.
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$130,000	Based on 2% of the capital cost.
Maintenance Labor	$130,000	Based on 2% of the capital cost.
Total Fixed O&M Cost	$260,000	
Indirect Operating Cost		
Property Taxes	$81,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$81,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$162,000	
Total Annual Operating Cost	$115,300	

6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$1,752,000	
Annual Operating Cost	$115,300	
Total Annual Cost	$1,867,300	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - SOOTBLOWING

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO_2 Emissions (tpy)	1,681,605
Post HRI CO_2 Emissions (tpy)	1,669,834
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$1,916,000	Based on $54,500 per sootblower for materials and $35,000 for BOP. 4 new sootblowers per boiler. $75,000 per sootblower to replace/repair 8 of the existing sootblowers
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$1,916,000	
Direct Installation Costs		
Installation	$218,000	Assumed to be 50% of new installation costs
Total Direct Capital Costs (DC)	$2,134,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	
Contingency	$383,000	20% of equipment costs
Hawaii Cost Adder	$87,200	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$2,604,000	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor $= i(1+i)^n / ((1+i)^n - 1)$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$563,000	Based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$409,718	Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$20,000	Based on $57/ton
Auxiliary Power Cost Differential	$0	
Total Variable O&M Costs	-$429,718	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$210,000	Based on $7,500/year per sootblower for maintenance split between materials and labor. 28 sootblowers per boiler.
Maintenance Labor	$210,000	Based on $7,500/year per sootblower for maintenance split between materials and labor. 28 sootblowers per boiler.
Total Fixed O&M Cost	$420,000	
Indirect Operating Cost		
Property Taxes	$26,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$26,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$52,000	
Total Annual Operating Cost	$42,300	

6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$563,000	
Annual Operating Cost	$42,300	
Total Annual Cost	$605,300	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - AIR HEATER TEMPERATURE REDUCTION

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,681,605
Post HRI CO2 Emissions (tpy)	1,668,993
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$11,350,000	30% additional surface area addition. Based on $4,000,000 (per boiler) cost for replacement of entire air heater
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$11,350,000	
Direct Installation Costs		
Installation	$9,000,000	Assumed to be $4.5 million per air heater of PEC
Total Direct Capital Costs (DC)	$20,350,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$22,176,000	Calculated lost profit over 22 weeks based on 24 week outage for air heater upgrade work, 2 of which are part of planned outage
PPA Penalty	$48,125,000	Penalties accrued considering 50% maximum capacity factor based on an 85% guarantee, assessed at $137,500 per 1/10% lower than guarantee
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$70,301,000	
Contingency	$2,270,000	20% of equipment costs
Hawaii Cost Adder	$3,600,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$96,521,000	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	20,879,000	Based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
		Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil
		Spec used oil cost $0.25 based on AES reporting
		TDF cost $50/ton based on AES reporting
Fuel Cost Differential	-$439,000	Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$22,000	Based on $57/ton
Auxiliary Power Cost Differential	$22,000	Based on 30% increase in pressure drop over air heater
Total Variable O&M Costs	-$439,000	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$116,100	Based on 1.5% of Direct Capital Cost for additonal surface area only.
Maintenance Labor	$116,100	Based on 1.5% of Direct Capital Cost for additonal surface area only.
Total Fixed O&M Cost	$232,200	
Indirect Operating Cost		
Property Taxes	$965,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$965,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$1,930,400	
Total Annual Operating Cost	$1,723,600	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$20,879,000	
Annual Operating Cost	$1,723,600	
Total Annual Cost	$22,602,600	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - HEAT RATE IMPROVEMENT COMBINATION (LOW COST OPTION)

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,681,605
Post HRI CO2 Emissions (tpy)	1,664,789
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$5,678,000	VFDs on ID and FD fans (one each boiler) based on a cost of $570/hp Sootblowing upgrades based on $54,500 per sootblower for materials and $35,000 for BOP. 4 new sootblowers per boiler. $75,000 per sootblower to replace/repair 8 of the existing sootblowers
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$5,678,000	
Direct Installation Costs		
Installation	$1,347,000	Assumed to be 50% of sootblower PEC and 30% of VFD upgrades PEC
Total Direct Capital Costs (DC)	$7,025,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	
Contingency	$1,136,000	20% of equipment costs
Hawaii Cost Adder	$539,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$8,700,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n/(1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	1,882,000	based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$585,312	Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$29,000	Based on $57/ton
Auxiliary Power Cost Differential	$0	
Total Variable O&M Costs	-$614,312	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$307,800	Based on 2% of capital cost.
Maintenance Labor	$307,800	Based on 2% of capital cost.
Total Fixed O&M Cost	$615,600	
Indirect Operating Cost		
Property Taxes	$87,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$87,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$174,000	
Total Annual Operating Cost	$175,300	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$1,882,000	
Annual Operating Cost	$175,300	
Total Annual Cost	$2,057,300	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - TURBINE UPGRADE

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO_2 Emissions (tpy)	1,681,605
Post HRI CO_2 Emissions (tpy)	1,660,585
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	**AES Hawaii Unit 1**	**Basis**
Direct Capital Costs		
Direct Costs	$11,000,000	Turbine Upgrade Equipment = $10,000,000 baed on HP/IP & LP sections at $5 million apiece; $1,000,000 additional owners cost
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$11,000,000	
Direct Installation Costs		
Installation	$4,000,000	Based on vendor information
Total Direct Capital Costs (DC)	$15,000,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$6,048,000	Calculated lost profit over 6 weeks based on 8 week outage for turbine upgrade work, 2 of which are part of planned outage
PPA Penalty	$13,750,000	Penalties accrued considering 75% capacity factor for the year (10% capacity factor reduction). Penal based on an 85% guarantee, assessed at $137,500 per 1/10% lower than guarantee
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$19,798,000	
Contingency	$2,200,000	20% of equipment costs
Hawaii Cost Adder	$1,600,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$38,598,000	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	8,349,000	Based on 6-year remaining useful life of equipment
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$731,640	Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil; Spec used oil cost $0.25 based on AES reporting; TDF cost $50/ton based on AES reporting; Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$36,000	Based on $57/ton
Auxiliary Power Cost Differential	$0	
Total Variable O&M Costs	-$767,640	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$0	No additional maintenance material s required.
Maintenance Labor	$0	No additional maintenance labor required.
Total Fixed O&M Cost	$0	
Indirect Operating Cost		
Property Taxes	$386,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$386,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$772,000	
Total Annual Operating Cost	$4,400	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$8,349,000	
Annual Operating Cost	$4,400	
Total Annual Cost	$8,353,400	

GHG Cost Evaluation
Fuel Oil Co-Firing

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - FUEL OIL CO-FIRING - 10% HEAT INPUT

	INPUT
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,681,605**
Post Fuel Oil Co-Firing CO2 Emissions (tpy)	**1,646,361**
Capacity Factor used of Cost Estimates (%)	**94%**

CAPITAL COSTS	**AES Hawaii Unit 1**	**Basis**
Direct Costs	$650,000	Includes 1 x 500,000 gal fuel oil storage tank, interconnecting piping, and transfer pumps
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$650,000	
Installation	$195,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	**$845,000**	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage.
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties.
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	Included in equipment cost
Contingency	$130,000	20% of equipment costs
Hawaii Cost Adder	$78,000	Assumed 40% higher labor cost than mainland.
Total Capital Investment (TCI)	**$1,053,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest.
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$228,000**	based on 6-year remaining useful life of equipment

OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	$17,976,500	Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton.
Disposal Cost Differential	-$288,000	Based on $57/ton.
Total Variable O&M Costs	$17,688,500	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for oil firing.
Operating Labor	$0	2 shifts/day, 365 days/year @ $49.50/hour
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$26,000	Based on 4% of TEC.
Maintenance Labor	$26,000	Based on 4% of TEC.
Total Fixed O&M Cost	$52,000	
Indirect Operating Cost		
Property Taxes	$10,500	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$10,500	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$21,000	
Total Annual Operating Cost	**$17,761,500**	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$228,000**	
Annual Operating Cost	**$17,761,500**	
Total Annual Cost	**$17,989,500**	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - HEAT RATE IMPROVEMENT COMBINATION (ALL OPTIONS)

	INPUT
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,681,605**
Post HRI CO2 Emissions (tpy)	**1,629,055**
Capacity Factor used of Cost Estimates (%)	**94%**

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$33,028,000	VFDs on ID and FD fans (one each boiler) based on a cost of $[illegible]/hp Turbine Upgrade Equipment = $10,000,000 based on HP IP & LP sections at $5 million apiece $1,000,000 additional owners cost Air heater upgrade includes 30% additional surface area addition. Based on $4,000,000 cost for replacement of entire air heater Sootblowing upgrades based on $54,500 per sootblower for materials and $35,000 for BOP. 4 new sootblowers per boiler. $75,000 per sootblower to replace repair 8 of the existing sootblowers DCS system upgrade cost of $5,000,000, including Boilers A & B
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$33,028,000	
Direct Installation Costs		
Installation	$15,847,000	Assumed to be 100% of All upgrades PEC, $4,000,000 turbine upgrades, 30% of VFD and DCS upgrades, 50% of sootblower upgrades
Total Direct Capital Costs (DC)	**$48,875,000**	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$22,176,000	Calculated lost profit over 22 weeks based on 24 week outage for turbineand air heater upgrade work, 2 of which are part of planned outage
PPA Penalty	$48,125,000	Penalties accrued considering 50% maximum capacity factor based on an 85% guarantee, assessed at $137,500 per 1/10% lower than guarantee
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	**$70,301,000**	
Contingency	$6,606,000	20% of equipment costs
Hawaii Cost Adder	$6,339,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	**$132,121,000**	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / ((1+i)^n - 1)$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	28,580,000	based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	-$1,829,099	Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$91,000	Based on $57/ton
Auxiliary Power Cost Differentia	$22,000	Based on 30% increase in pressure drop over air heater
Total Variable O&M Costs	-$1,898,099	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for heat rate improvement projects
Operating Labor	$0	2 shifts/day, 365 days/year @ 49.5/hour (salary + benefits)
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$553,900	Based on 1.5% of Air Heater upgrade DCC plus 2% of capital cost of VFDs, DCS, and sootblowing upgrades.
Maintenance Labor	$553,900	Based on 1.5% of Air Heater upgrade DCC plus 2% of capital cost of VFDs, DCS, and sootblowing upgrades.
Total Fixed O&M Cost	$1,107,800	
Indirect Operating Cost		
Property Taxes	$1,321,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,321,200	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$2,642,400	
Total Annual Operating Cost	**$1,852,100**	

6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$28,580,000**	
Annual Operating Cost	**$1,852,100**	
Total Annual Cost	**$30,432,100**	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - FUEL OIL CO-FIRING - 30% HEAT INPUT

	INPUT
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,681,605**
Post Fuel Oil Co-Firing CO2 Emissions (tpy)	**1,575,411**
Capacity Factor used of Cost Estimates (%)	**94%**

CAPITAL COSTS	**AES Hawaii Unit 1**	**Basis**
Direct Costs	$1,480,000	Includes 2 x 500,000 gal fuel oil storage tank, interconnecting piping, and transfer pumps with new burner locations
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$1,480,000	
Installation	$444,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	$1,924,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage.
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties.
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	Included in equipment cost
Contingency	$296,000	20% of equipment costs
Hawaii Cost Adder	$177,600	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$2,397,600	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / ((1+i)^n - 1)$	0.2163	6 year life of equipment (years) @ 8% interest.
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$519,000	based on 6-year remaining useful life of equipment

OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Fuel Cost Differential	$54,164,388	Coal cost and fuel oil costs based on 2015 average as delivered $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton
Disposal Cost Differential	-$869,000	Based on $57/ton
Total Variable O&M Costs	$53,295,388	
Fixed O&M Costs		
Additional Operators per shift	0.0	Based on S&L O&M estimate for oil firing.
Operating Labor	$0	2 shifts/day, 365 days/year @ $49.50/hour.
Supervisor Labor	$0	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$59,200	Based on 4% of TEC.
Maintenance Labor	$59,200	Based on 4% of TEC.
Total Fixed O&M Cost	$118,400	
Indirect Operating Cost		
Property Taxes	$24,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$24,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$48,000	
Total Annual Operating Cost	$53,461,800	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$519,000	
Annual Operating Cost	$53,461,800	
Total Annual Cost	$53,980,800	

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - LOCAL EUCALYPTUS BIOMASS CO-FIRING - 150,000 TPY

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO_2 Emissions (tpy)	1,681,605
Post Biomass Co-Firing CO_2 Emissions (tpy)	1,469,480
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$19,000,000	Price estimated based on in-house estimates for similar projects. Includes cost for shredding and grinding equipment, conveyors, live bin hoppers, screw feeders, and storage. Total cost also includes DSI system for hydrated lime injection for HCl emission control
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$19,000,000	
Direct Installation Costs		
Installation	$5,700,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	$24,700,000	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	$0	Included in equipment cost
Contingency	$3,800,000	20% of equipment costs
Hawaii Cost Adder	$2,280,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	$30,780,000	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$6,658,000	Based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Hydrated Lime Reagent Cost	$210,858	200 lb/hr injection rate based on 73% HCl reduction to achieve MATS compliance @ $255/ton
Fuel Cost Differential	$24,123,599	Accounts for increased heat rate with biomass co-firing Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton Biomass based on local eucalyptus $210/ST delivered
Disposal Cost Differential	$3,275,000	Based on $57/ton
Total Variable O&M Costs	$27,609,457	
Fixed O&M Costs		
Additional Operators per shift	3.5	Based on S&L O&M estimate for additional DSI (0.5) and fuel handling (3) operators
Operating Labor	$1,517,700	2 shifts/day, 365 days/year @ $49.50/hour
Supervisor Labor	$227,700	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$247,000	Based on 1.0% of DCC.
Maintenance Labor	$247,000	Based on 1.0% of DCC.
Total Fixed O&M Cost	$2,239,400	
Indirect Operating Cost		
Property Taxes	$307,800	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$307,800	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$615,600	
Total Annual Operating Cost	$30,464,500	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	$6,658,000	
Annual Operating Cost	$30,464,500	
Total Annual Cost	$37,122,500	

GHG Cost Evaluation
Biomass Co-Firing

AES Hawaii Units 1A & 1B
GHG COST EVALUATION - PELLETIZED BIOMASS CO-FIRING - 25%

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO_2 Emissions (tpy)	1,681,605
Post Biomass Co-Firing CO_2 Emissions (tpy)	1,412,549
Capacity Factor used of Cost Estimates (%)	94%

CAPITAL COSTS	AES Hawaii Unit 1	Basis
Direct Capital Costs		
Direct Costs	$13,000,000	Price estimated based on in-house estimates for similar projects. Includes cost for pellet conveying, surge bins, screw conveyors, and domed storage area. Total cost also includes DSI system for hydrated lime injection for HCl emission control
Instrumentation	$0	Included in equipment cost
Sales Taxes	$0	Included in equipment cost
Freight	$0	Included in equipment cost
Total Purchased Equipment Cost (PEC)	$13,000,000	
Direct Installation Costs		
Installation	$3,900,000	Assumed to be 30% of PEC
Total Direct Capital Costs (DC)	**$16,900,000**	Sum of purchased equipment costs and installation costs
Indirect Capital Costs		
Engineering	$0	Included in equipment cost
Construction and Field Expenses	$0	Included in equipment cost
Contractor Fees	$0	Included in equipment cost
Lost Production	$0	Tie-in of new equipment completed during normal 2 week maintenance outage
PPA Penalty	$0	Tie-in of new equipment completed during normal 2 week maintenance outage will not accrue penalties
Start-Up	$0	Included in equipment cost
Performance Testing	$0	Included in equipment cost
Total Indirect Capital Costs (IC)	**$0**	Included in equipment cost
Contingency	$2,600,000	20% of equipment costs
Hawaii Cost Adder	$1,560,000	Assumed 40% higher labor cost than mainland
Total Capital Investment (TCI)	**$21,060,000**	Sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.2163	6 year life of equipment (years) @ 8% interest
6-Year Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$4,556,000**	Based on 6-year remaining useful life of equipment

OPERATING COSTS		Basis
Operating & Maintenance Costs		
Variable O&M Costs		
Hydrated Lime Reagent Cost	$210,858	200 lb/hr injection rate based on 73% HCl reduction to achieve MATS compliance @$255/ton
Fuel Cost Differential	$23,581,257	Accounts for heat rate increase due to co-firing biomass Coal cost and fuel oil costs based on 2015 average as delivered. $78.13/ton coal and $2.09/gal fuel oil Spec used oil cost $0.25 based on AES reporting TDF cost $50/ton based on AES reporting Spent activated carbon based on profit of $25/ton Biomass based on pelletized delivery cost of $1[illegible].49/MT
Disposal Cost Differential	$4,010,000	Based on $57/ton
Total Variable O&M Costs	$27,802,116	
Fixed O&M Costs		
Additional Operators per shift	1.5	Based on S&L O&M estimate for additional DSI (0.5) and fuel handling (1) operators
Operating Labor	$650,400	2 shifts/day, 365 days/year @ $49.50/hour
Supervisor Labor	$97,600	15% of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$169,000	Based on 1.0% of DCC.
Maintenance Labor	$169,000	Based on 1.0% of DCC.
Total Fixed O&M Cost	$1,086,000	
Indirect Operating Cost		
Property Taxes	$210,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$210,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	No additional cost.
Total Indirect Operating Cost	$421,200	
Total Annual Operating Cost	**$29,309,300**	
6-YEAR TOTAL ANNUAL COST (2015)		
Annualized Capital Cost	**$4,556,000**	
Annual Operating Cost	**$29,309,300**	
Total Annual Cost	**$33,865,300**	

APPENDIX B. 2010 ANNUAL BASELINE EMISSIONS CALCULATIONS FOR AES HAWAII

Appendix B

AES Hawaii: 2010 Baseline CO_{2e} Emission Summary

Unit	Fuel Type	CO_{2e}	Reporting Unit	Methodology
Boiler	Coal	1,503,958.66	Metric Tons	Tier 3
	TDF	0	Metric Tons	No TDF in 2010
	Activated Carbon	2,323.68	Metric Tons	Tier 2
	Fuel Oil No. 2	762.84	Metric Tons	Tier 2
	Spec Used Oil	6,240.96	Metric Tons	Tier 2
	Limestone	11,508.46	Metric Tons	Sorbent
Limestone Dryer	Fuel Oil No. 2	747.86	Metric Tons	Tier 1

Total CO_2 Emissions for the year 2010 = **1,525,542.44 Metric Tons**
1,681,605.43 Short Tons

Reported to EPA on 1/4/2017
Annual Non-Biogenic CO2 emissions **1,514,070.46** Metric Tons
Annual CH4 emissions **173.50** Metric Tons
Annual N2O emissions **25.25** Metric Tons

Table 2-1: AES Hawaii 2010 Facility-wide Baseline Emissions (Metric Tons)

	CO_2		N_2O		CH_4		Total CO2e(1)
	Non-Biogenic, Metric tons/yr	Biogenic, Metric tons/yr	Metric tons/yr, as N2O	Metric tons/yr, as CO2e(1)	Metric tons/yr, as CH4	Metric tons/yr, as CO2e(1)	Metric tons/yr
Boilers A and B (total)	1,513,325.11	0	25.25	7,826.64	173.47	3,642.84	1,524,794.58
Limestone Dryers	745.35	0	0.01	1.87	0.03	0.63	747.86
Facility-Wide Total	1,514,070.46	0	25.25	7,828.51	173.50	3,643.47	1,525,542.44

Note 1. CO2e emissions calculated based on 2010 GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO2 = 1, N2O = 310, CH4 = 21).

Table 2-1: AES Hawaii 2010 Facility-wide Baseline Emissions (Short Tons)

	CO_2		N_2O		CH_4		Total CO2e(1)
	Non-Biogenic, Short tons/yr	Biogenic, Short tons/yr	Short tons/yr as N2O	Short tons/yr as CO2e(1)	Short tons/yr as CH4	Short tons/yr as CO2e(1)	Short tons/yr
Boilers A and B (total)	1,668,138	0	28	8,627	191	4,015	1,680,781
Limestone Dryers	822	0	0	2	0	1	824
Facility-Wide Total	1,668,960	0	28	8,629	191	4,016	1,681,605

Note 1. CO2e emissions calculated based on 2010 GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO2 = 1, N2O = 310, CH4 = 21).

1 Metric Tons = 1.1023 Short Tons

Appendix C. GHG Reduction Partnership

Table A-1: ERP Partnership Baseline CO_2e Emissions and Proposed CSP Limits (1)

Company	Covered Source	Baseline CO2e Emissions (metric tpy)	Baseline CO2e Emissions (tpy)	CSP Limits CO2e Reduction (%)	CSP Limits CO2e Reduction (tpy)	CSP Limits CO2e Limit (tpy)
Hawaiian Electric (HE)	Kahe	2,518,411	2,776,073	23.1%	642,321	2,133,752
	Waiau	974,642	1,074,359	24.8%	266,074	808,286
	Honolulu	121,208	133,609	100.0%	133,609	0
	CIPGS	13,559	14,946	-259.6%	-38,794	53,740
HESubtotal		3,627,821	3,998,988	25.1%	1,003,210	2,995,778
Maui Electric (ME)	Kahului	209,414	230,839	33.0%	76,206	154,633
	Maalaea	562,012	619,512	25.8%	159,649	459,864
	Palaau	25,615	28,236	6.3%	1,782	26,454
ME Subtotal		797,041	878,587	27.0%	237,636	640,951
Hawai'i Electric Light (HEL)	Kanoelehua-Hill	202,106	222,784	22.6%	50,328	172,456
	Keahole	173,623	191,387	-26.6%	-50,821	242,208
	Puna	90,438	99,691	68.2%	67,944	31,747
	Shipman	9,246	10,192	100.0%	10,192	0
HEL Subtotal		475,413	524,053	14.8%	77,642	446,411
Hawaiian Electric Companies		**4,900,275**	**5,401,629**	**24.4%**	**1,318,488**	**4,083,141**
AES Hawai'i		**1,525,526**	**1,681,605**	**-0.6%**	**-10,000**	**1,691,605**
Hamakua Energy Power		**165,992**	**182,975**	**16.0%**	**29,276**	**153,699**
Kalaeloa Partners, LP		**993,198**	**1,094,813**	**0.0%**	**0**	**1,094,813**
Partnership Total		**7,584,991**	**8,361,022**	**16.00%**	**1,337,764**	**7,023,258**

Notes:

(1) Table A-2 applies for calendar year 2019 only due to loss of PGV renewable energy.

(2) Selections of facility emissions baselines are described in the individual GHG Emission Reduction Plans for the Hawaiian Electric Companies, AES Hawai'i, Kalaeloa Partners, LP (KPLP), and Hamakua Energy Power (HEP).

(3) CIPGS (Campbell Industrial Park Generating Station) is designated as the Main CSP for the Hawaiian Electric Companies' Emissions Reduction Plan.

Table A-2: Substitute 2019 GHG Limits for PGV Outage

Company	Covered Source	PGV 100% Operation CO2e Emissions Limit (tpy)	Calendar Year 2019 GHG Limits GHG Limit Adjustment (tpy)	Calendar Year 2019 GHG Limits CO_2e Emissions Limit (tpy)
HECO	Kahe	2,133,752	0	2,133,752
	Waiau	808,286	0	808,286
	Honolulu	0	0	0
	CIPGS	53,740	0	53,740
HE Subtotal		2,995,778	0	2,995,778
MECO	Kahului	154,633	0	154,633
	Maalaea	459,864	0	459,864
	Palaau	26,454	0	26,454
ME Subtotal		640,951	0	640,951
HELCO	Kanoelehua-Hill	172,456	17,132	189,588
	Keahole	242,208	31,213	273,421
	Puna	31,747	39,535	71,282
	Shipman	0	0	0
HEL Subtotal		446,411	87,880	534,291
Hawaiian Electric Companies		**4,083,140**	**87,880**	**4,171,020**
AES Hawai'i		**1,691,605**	**0**	**1,691,605**
Hamakua Energy Power		**153,699**	**97,524**	**251,223**
Kalaeloa Partners, LP		**1,094,813**	**0**	**1,094,813**
Partnership Total		**7,023,257**	**185,404**	**7,208,661**