ADMINISTRATIVE RECORD

AES HAWAII, LLC
203 MW Coal-Fired Cogeneration Plant

Application for Significant Modification No. 0087-09

Located At: 91-086 Kaomi Loop, Kapolei, Oahu

CSP No. 0087-02-C

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PUBLIC NOTICE

REQUEST FOR PUBLIC COMMENTS
ON DRAFT AIR PERMITS
REGULATING THE EMISSIONS OF AIR POLLUTANTS

(Docket No. 20-CA-PA-06)

Pursuant to Hawaii Revised Statutes (HRS), Chapter 342B-13, and Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, State of Hawaii (DOH), is requesting public comments on **DRAFT PERMITS** presently under review for the following affected facilities subject to greenhouse gas (GHG) emission reductions:

A. Independent Power Producers (IPPs)

(1) Amendment of Covered Source Permit (CSP) No. 0087-02-C
Application for Significant Modification No. 0087-09
AES Hawaii, LLC (AES)
203 MW Coal-Fired Cogeneration Plant
Located At: 91-086 Kaomi Loop, Kapolei, Oahu

(2) Amendment of Covered Source Permit (CSP) No. 0243-01-C
Application for Significant Modification No. 0243-07
Hamakua Energy, LLC (Hamakua Energy)
Hamakua Energy Plant (HEP)
65 MW Cogeneration Facility
Located At: 45-300 Lehua Street, Honokaa, Hawaii

(3) Amendment of Covered Source Permit (CSP) No. 0214-01-C
Application for Significant Modification No. 0214-10
Kalaeloa Partners, L.P. (KPLP)
Kalaeloa Cogeneration Plant (KCP)
223.5 MW Kalaeloa Cogeneration Plant
Located At: 91-111 Kalaeloa Boulevard, Kapolei, Oahu

B. Hawaiian Electric Companies

(1) Amendment of Covered Source Permit (CSP) No. 0548-01-C
Application for Significant Modification No. 0548-09
Hawaiian Electric Company, Inc. (HECO)
Campbell Industrial Park (CIP) Generating Station
Located At: 91-196 Hanua Street, Kapolei, Oahu

(2) Amendment of Covered Source Permit (CSP) No. 0240-01-C
Application for Significant Modification No. 0240-08
Hawaiian Electric Company, Inc. (HECO)
Kahe Generating Station
Located At: 92-200 Farrington Highway, Waianae, Oahu

(3) **Amendment of Covered Source Permit (CSP) No. 0238-01-C**
Application for Significant Modification No. 0238-05
Hawaiian Electric Company, Inc. (HECO)
Honolulu Generating Station
Located At: 170 Ala Moana Boulevard, Honolulu, Oahu

(4) **Amendment of Covered Source Permit (CSP) No. 0239-01-C**
Application for Significant Modification No. 0239-06
Hawaiian Electric Company, Inc. (HECO)
Waiau Generating Station
Located At: 475 Kamehameha Highway, Pearl City, Oahu

(5) **Amendment of Covered Source Permit (CSP) No. 0234-01-C**
Application for Significant Modification No. 0234-05
Hawaii Electric Light Company, Inc. (HELCO)
Kanoelehua-Hill Generating Station
Located At: 54 Halekauila Street, Hilo, Hawaii

(6) **Amendment of Covered Source Permit (CSP) No. 0007-01-C**
Application for Significant Modification No. 0007-07 (0007-01-C)
Application for Significant Modification No. 0070-04 (0070-01-C)
Hawaii Electric Light Company, Inc. (HELCO)
Keahole Generating Station
Located At: 73-4249 Pukiawe Street, Kailua Kona, Hawaii

(7) **Amendment of Covered Source Permit (CSP) No. 0235-01-C**
Application for Significant Modification No. 0235-04
Hawaii Electric Light Company, Inc. (HELCO)
Puna Generating Station
Located At: Puna Mill Road, Keaau, Hawaii

(8) **Amendment of Covered Source Permit (CSP) No. 0232-01-C**
Application for Significant Modification No. 0232-06
Maui Electric Company, Ltd. (MECO)
Kahului Generating Station
Located At: 200 Hobron Avenue, Kahului, Maui

(9) **Amendment of Covered Source Permit (CSP) No. 0067-01-C**
Application for Significant Modification No. 0067-14 (0067-01-C)
Application for Significant Modification No. 0067-15 (0067-02-C)
Maui Electric Company, Ltd. (MECO)
Maalaea Generating Station
Located At: Maalaea Generating Station, Maalaea, Maui

(10) **Amendment of Covered Source Permit (CSP) No. 0031-04-C**
Application for Significant Modification No. 0031-08
Maui Electric Company, Ltd. (MECO)
Palaau Generating Station
Located At: 32 Ulili Street, Kaunakakai, Molokai

The **DRAFT PERMITS** are described as follows:

The permit amendments incorporate GHG emission caps in accordance with HAR Chapter 11-60.1, Subchapter 11, to limit GHG emissions from affected facilities. Affected facilities are permitted covered sources with potential carbon dioxide equivalent (CO_2e) emissions (biogenic plus nonbiogenic) equal to or greater than 100,000 short tons per year.

Pursuant to HAR Chapter 11-60.1, Subchapter 11, the amendments incorporate provisions for partnering between thirteen (13) electric plants to combine emissions for flexibility in achieving the GHG reductions. Three (3) affected facilities are independent power producers (IPPs) owned and operated by AES, Hamakua Energy, and KPLP. The remaining ten (10) affected facilities are from the Hawaiian Electric Companies that include HECO, HELCO, and MECO.

The partnering facilities propose a total combined GHG emission baseline for establishing the facility-wide GHG emissions cap of 7,584,991 metric tons (8,361,022 short tons) per year. Partnering facilities used 2010 as the baseline year, except for the KCP cogeneration plant which used 2009 for its baseline year because 2010 was deemed unrepresentative due to an overhaul of its steam turbine generator. Emissions from HECO's Shipman Generating Station which closed at the end of 2015 were included in the baseline emissions. The total combined GHG emissions cap proposed for the partnering facilities for calendar year 2020 and beyond is 6,371,392 metric tons (7,023,257 short tons) of CO_2e emissions per calendar year which is a 16% reduction from the proposed total combined GHG emission baseline level.

For calendar year 2019, cap adjustments are necessary to compensate for the continuing unavailability of renewable energy from Puna Geothermal Venture (PGV) and delays to new renewable energy projects for reasons outside of the control of the partnering facilities. The cap adjustments will temporarily increase the total combined GHG emissions cap proposed for the partnering facilities to 6,539,587 metric tons (7,208,661 short tons) for a 13.78% reduction from the proposed total combined GHG emission baseline level. Alternate operating scenarios are added to the permits for continuing with the cap adjustments by adding one twelfth (1/12) of the 2019 annual adjustments for every month that PGV generation is delayed into and beyond calendar year 2020. The 2019 annual CO_2e adjustments for each individual facility on the island of Hawaii only are 97,524 short tons for Hamakua Energy, LLC, 17,132 short tons for Kanoelehua-Hill Generating Station, 31,213 short tons for Keahole Generating Station, and 39,535 short tons for Puna Generating Station. The total combined CO_2e adjustment for these facilities is 185,404 short tons. For delays in PGV generation into and beyond calendar year 2020, monthly adjustments for each individual facility on the island of Hawaii are 8,127 short tons for Hamakua Energy, LLC, 1,428 short tons for Kanoelehua-Hill Generating Station, 2,601 short tons for Keahole Generating Station, and 3,295 short tons for Puna Generating Station for a total monthly CO_2e adjustment of 15,450 short tons. These alternate operating scenarios apply to each individual cap for partnering facilities on the island of Hawaii and the total combined emissions cap for all partnering facilities until PGV restores net generation of electricity to levels that that preceded it's shutdown due to the volcanic activity that was determined to be 26,883 MWh. Once net generation of 26,883 MWh per month from the PGV facility is reached, the alternate operating scenarios no longer applies and no further adjustments will be made to the CO_2e emissions caps, thereafter.

For calendar year 2020 and beyond, AES further reduced its individual GHG emissions cap by 16% below its individual GHG emission baseline level. Emissions from the AES cap adjustments were distributed evenly among partnering facilities on the island of Oahu, excluding the AES plant and the HECO Honolulu Generating Station.

The three (3) IPP permits and CSP No. 0548-01-C for HECO's CIP Generating Station will specify individual and total combine GHG emission caps established for the partnering facilities. Any GHG emission cap revision will require each of these facilities (AES, Hamakua Energy, KPLP, and HECO's CIP Generating Station) to submit a significant permit modification for the change.

The permits for the remaining partnering facilities operated by HECO, HELCO, and MECO will not specify individual and total combined GHG emission caps, but instead reference GHG emission caps included in CSP No. 0548-01-C for HECO's CIP Generating Station. Designating CSP No. 0548-01-C as the main permit will reduce the burden of modifying all Hawaiian Electric Companies' permits should an emissions cap be revised. Only CSP No. 0548-01-C would require modification as the emission caps will not be incorporated separately into each facility's permit.

Individual and total combined GHG emission caps were established in each facility's GHG emission reduction plan. Each facility may exceed its individual cap as long as the total combined GHG emissions cap is met. Biogenic carbon dioxide emissions are excluded in determining compliance with the CO_2e emissions caps.

A. Independent Power Producers (IPPs)

(1) The significant modification of **CSP No. 0087-02-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 1,534,598 metric tons (1,691,605 short tons) for calendar year 2019 and 1,281,442 metric tons (1,412,548 short tons) for calendar year 2020 and beyond that applies specifically to the AES cogeneration plant. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emissions cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(2) The significant modification of **CSP No. 0243-01-C** will grant conditional approval to temporarily increase individual CO_2e emissions cap to 227,906 metric tons (251,223 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emission cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. For 2020 and beyond, an individual CO_2e emissions cap of 139,433 metric tons (153,699 short tons) is specified for the Hamakua Energy cogeneration plant. The conditional approval includes temporarily increasing the total combined CO_2e

emission cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emissions cap of 6,371,392 metric tons (7,023,257 short tons is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(3) The significant modification of **CSP No. 0214-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 993,198 metric tons (1,094,813 short tons) for calendar year 2019 and 1,056,486 metric tons (1,164,577 short tons) for calendar year 2020 and beyond that applies specifically to the KPLP cogeneration plant. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

B. <u>Hawaiian Electric Companies</u>

(1) The significant modification of **CSP No. 0548-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 48,752 metric tons (53,740 short tons) for calendar year 2019 and 112,041 metric tons (123,504 short tons) for calendar year 2020 and beyond that applies specifically to the HECO CIP Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(2) The significant modification of **CSP No. 0238-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap 0 metric tons (0 short tons) per calendar year that applies specifically to the HECO Honolulu Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(3) The significant modification of **CSP No. 0240-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap 1,935,707 metric tons (2,133,752 short tons) for calendar year 2019 and 1,998,996 metric tons (2,203,516 short tons) for calendar year 2020 and beyond that applies specifically to the HECO Kahe Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(4) The significant modification of **CSP No. 0239-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 733,265 metric tons (808,286 short tons) for calendar year 2019 and 796,554 metric tons (878,050 short tons) for calendar year 2020 and beyond that applies specifically to the HECO Waiau Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed beyond into and beyond calendar year 2020 to a total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) in partnering with all other affected facilities. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(5) The significant modification of **CSP No. 0234-01-C** will grant conditional approval to temporarily increase the individual CO_2e emissions cap to 171,991 metric tons (189,588 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. For calendar year 2020 and beyond, an individual CO_2e emissions cap of 156,449 metric tons (172,456 short tons) per calendar year is specified for the HELCO Kanoelehua-Hill Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emission cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once PGV net generation of 26,883 MWh per month is reached.

(6) The significant modification of **CSP No. 0007-01-C** will grant conditional approval to temporarily increase the individual CO_2e emissions cap to 248,043 metric tons (273,421 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. For calendar year 2020 and beyond, an individual CO_2e emissions cap of 219,727 metric tons (242,208 short tons) per calendar year is specified for the HELCO Keahole Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(7) The significant modification of **CSP No. 0235-01-C** will grant conditional approval to temporarily increase the individual CO_2e emissions cap to 64,666 metric tons (71,282 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. For calendar year 2020 and beyond an individual CO_2e emissions cap of 28,800 metric tons (31,747 short tons) per calendar year for the HELCO Puna Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(8) The significant modification of **CSP No. 0232-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 140,281 metric tons (154,633 short tons) per calendar year that applies specifically to the MECO Kahului Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

(9) The significant modification of **CSP No. 0067-01-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 417,182 metric tons (459,864 short tons) per calendar year that applies specifically to the MECO Maalaea Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once PGV net generation of 26,883 MWh per month is reached.

(10) The significant modification of **CSP No. 0031-04-C** will grant conditional approval to incorporate an individual CO_2e emissions cap of 23,999 metric tons (26,454 short tons) per calendar year that applies specifically to the MECO Palaau Generating Station. The conditional approval includes temporarily increasing the total combined CO_2e emissions cap proposed in partnering with the other affected facilities to 6,539,587 metric tons (7,208,661 short tons) for calendar year 2019 and an alternate operating scenario that adds one twelfth (1/12) of the 2019 annual adjustments to the 2020 and beyond GHG emissions cap for every month that PGV's restoration is delayed into and beyond calendar year 2020. A total combined CO_2e emission cap of 6,371,392 metric tons (7,023,257 short tons) is specified for calendar year 2020 and beyond. The alternate operating scenarios will no longer apply once a net generation of 26,883 MWh per month from PGV is reached.

The **ADMINISTRATIVE RECORDS**, consisting of the **APPLICATIONS, GHG EMISSION REDUCTION PLANS,** and non-confidential supporting material from the applicant, the permit review summary, and the **DRAFT PERMITS**, are available for public inspection during regular office hours, Monday through Friday, 7:45 a.m. to 4:15 p.m., at the following locations:

Oahu:

State of Hawaii
Clean Air Branch
2827 Waimano Home Road, #130
Pearl City, HI 96782

Hawaii:

Hilo: Hawaii District Health Office, Department of Health
1582 Kamehameha Avenue, Hilo, Hawaii 96720

Kona: Sanitation Branch, Department of Health
79-1020 Haukapila Street, Room 115, Kona, Hawaii 96750

Maui:

Maui District Health Office, Department of Health
54 High Street, Wailuku, Maui 96793

Kauai:

Kauai District Health Office, Department of Health
3040 Umi Street, Lihue, Kauai 96766

All comments on the draft permits and any request for a public hearing must be in writing, addressed to the Clean Air Branch at the above address on Oahu and must be postmarked or received by **August 14, 2020**.

Any person may request a public hearing by submitting a written request that explains the party's interest and the reasons why a hearing is warranted. The DOH may hold a public hearing if a hearing would aid in DOH's decision. If a public hearing is warranted, a public notice for the hearing will be published at least thirty (30) days in advance of the hearing.

Interested persons may obtain copies of the administrative record or parts thereof by paying **five (5) cents per page copying costs**. Please send written requests to the Oahu office of the Clean Air Branch listed above or call Mr. Dale Hamamoto (CSPs for Hamakua Energy and KPLP facilities) or Mr. Michael Madsen (CSPs for AES, HECO, HELCO, and MECO facilities) at the Clean Air Branch office at (808) 586-4200. Electronic copies of the draft permits, permit reviews, and GHG emission reduction plans may be found online at http://health.hawaii.gov/cab/public-notices/.

Comments on the draft permits should address, but need not be limited to, the permit conditions and the facility's compliance with federal and state air pollution laws, including: (1) the National and State Ambient Air Quality Standards; and (2) HRS, Chapter 342B and HAR, Chapter 11-60.1.

DOH will make a final decision on the permits after considering all comments and will send notice of the final decision to each person who has submitted comments or requested such notice.

Bruce S. Anderson, Ph.D.
Director of Health

DRAFT PERMIT

DRAFT

DATE

CERTIFIED MAIL 20-xxxE CAB
<u>RETURN RECEIPT REQUESTED</u> File No. 0087
(xxxx xxxx xxxx xxxx xxxx)

Mr. Steven Barnoski
Plant Manager
AES Hawaii, LLC
91-086 Kaomi Loop
Kapolei, Hawaii 96707-1883

Dear Mr. Barnoski:

SUBJECT: Amendment of Covered Source Permit (CSP) No. 0087-02-C
Application for Significant Modification No. 0087-09
AES Hawaii, LLC
203 MW Coal-Fired Cogeneration Plant
Located At: 91-086 Kaomi Loop, Kapolei, Oahu
Date of Expiration: April 15, 2019 (Expiration Date to be Revised Upon Permit Renewal)

In accordance with Hawaii Administrative Rules (HAR), Chapter 11-60.1, and pursuant to your application for a significant permit modification received on March 28, 2018, significant permit modification application update received on July 30, 2019, greenhouse gas (GHG) emission reduction plan received on December 1, 2016, March 5, 2018, October 30, 2018, and July 30, 2019, and the additional information on January 23, 2020, February 14 , 2020, April 2, 2020, May 22, 2020, and June 9, 2020, from Hawaiian Electric Company, Inc. submitted on behalf of the partnership for cap adjustments, the Department of Health, Clean Air Branch (herein after referred to as Department), amends CSP No. 0087-02-C issued to AES Hawaii, LLC, on April 16, 2014, and amended on June 23, 2014.

In accordance with HAR, Chapter 11-60.1, Subchapter 11, the amendment incorporates provisions for partnering the AES Hawaii, LLC, cogeneration plant with other affected plants to combine emissions for flexibility in achieving GHG reductions. The amendment includes GHG emission cap adjustments for 2019 and a total combined GHG emission cap for 2020 and beyond that is a sixteen percent (16%) reduction from the combined partnership baseline GHG emissions level. The amendment also includes alternate operating scenarios for partnering facilities on the island of Hawaii in the event delays are encountered in restoring the Puna Geothermal Venture (PGV) facility to the net generation that preceded its shutdown in 2018. Individual and total combined GHG emission caps established in each facility's GHG emission reduction plan are incorporated in the amendment with associated provisions pursuant to HAR §11-60.1-204(d)(6)(C). The partnering facilities included in this amendment are:

Independent Power Producers (IPPs)

- AES Hawaii, LLC (AES), CSP No. 0087-02-C
- Hamakua Energy, LLC (Hamakua Energy), CSP No. 0243-01-C
- Kalaeloa Partners, L.P. (KPLP), CSP No. 0214-01-C

Hawaiian Electric Companies

- Hawaiian Electric Company, Inc. (HECO), CSP No. 0548-0-C
- Hawaiian Electric Company, Inc. (HECO), CSP No. 0238-01-C
- Hawaiian Electric Company, Inc. (HECO), CSP No. 0239-01-C
- Hawaiian Electric Company, Inc. (HECO), CSP No. 0240-01-C
- Hawaii Electric Light Company, Inc. (HELCO), CSP No. 0007-01-C
- Hawaii Electric Light Company, Inc. (HELCO), CSP No. 0234-01-C
- Hawaii Electric Light Company, Inc. (HELCO), CSP No. 0235-01-C
- Maui Electric Company, Ltd. (MECO), CSP No. 0031-04-C
- Maui Electric Company, Ltd. (MECO), CSP No. 0067-01-C
- Maui Electric Company, Ltd. (MECO), CSP No. 0232-01-C

The three (3) IPP permits and CSP No. 0548-01-C (HECO Campbell Industrial Park (CIP) Generating Station) will specify individual and total combine GHG emission caps established for all of the partnering facilities. Any GHG emission cap revision, except for reasonably anticipated alternate operating scenarios due to the PGV facility shutdown, will require each of these facilities (AES, Hamakua Energy, KPLP, and HECO CIP) to submit a significant permit modification.

The permits for the remaining partnering facilities operated by HECO, HELCO, and MECO will not specify individual and total combine GHG emission caps, but will reference GHG emission caps included in CSP No. 0548-01-C. Designating CSP No. 0548-01-C as the main HECO permit will reduce the burden of modifying all Hawaiian Electric Companies' permits should an emission cap be revised. Only CSP No. 0548-01-C would require modification as the emission caps will not be incorporated separately into each facility's permit.

CSP No. 0087-02-C issued on April 16, 2014, and amended on June 23, 2014, is amended as follows:

1) Added Attachment and Form:

   a) Attachment II - GHG: Special Conditions – GHG Reduction Requirements
   b) Monitoring Report Form: GHG Emissions

2) Superseded Attachment:

   a) Attachment III: Annual Fee Requirements

3) Superseded Condition:

a) Attachment I: Standard Condition No. 28:

28. **Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:**

State of Hawaii
Clean Air Branch
2827 Waimano Home Road, #130
Pearl City, HI 96782

Upon request and as required by this permit, all correspondence to the State of Hawaii Department of Health associated with this CSP shall have duplicate copies forwarded to:

Manager
Enforcement Division, Air Section
U.S. Environment Protection Agency, Region 9
75 Hawthorne Street, ENF-2-1
San Francisco, CA 94105

All other permit conditions of CSP No. 0087-02-C issued on April 16, 2014, and amended on June 23, 2014, shall not be affected and shall remain valid.

If there are any questions regarding these matters, please contact Mr. Michael Madsen of the Clean Air Branch at (808) 586-4200.

Sincerely,

_____________, P.E., ACTING CHIEF
Environmental Management Division

MM:tkg

Enclosures

DRAFT

ATTACHMENT II - GHG: SPECIAL CONDITIONS
GHG REDUCTION REQUIREMENTS
COVERED SOURCE PERMIT NO. 0087-02-C

Amended Date: DATE **Expiration Date: April 15, 2019**
(Expiration Date to be Revised Upon Permit Renewal)

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

Section A. Equipment Description

1. Attachment II - GHG of this permit encompasses the following equipment and associated appurtenances:

Equipment	Manufacturer	Capacity
Circulating Fluidized Bed Boiler A with Limestone Injection	Ahlstrom Pyropower Corporation	2,150 MMBtu/hr (see note a)
Circulating Fluidized Bed Boiler B with Limestone Injection	Ahlstrom Pyropower Corporation	
Limestone Dryer 1A	Micro Powder Systems	4.75 MMBtu/hr
Limestone Dryer 1B	Micro Powder Systems	4.75 MMBtu/hr

[a]Total combined capacity of Boilers A and B.

(Auth.: HAR §11-60.1-3)

2. The equipment is subject to GHG emission reduction requirements of HAR, Chapter 11-60.1, Subchapter 11, and associated permit conditions based on information from the GHG emission reduction plan and permit application for significant modification. The GHG emission reduction plan shall become a part of the CSP application process for renewals and any required modifications pursuant to HAR, Chapter 11-60.1, Subchapter 5. With each subsequent GHG emission reduction plan submittal, the permittee shall report:

   a. The GHG emission reduction status;
   b. Factors contributing to the emission changes;
   c. Any control measure updates; and
   d. Any new developments or changes that would affect the basis of the facility-wide GHG emissions cap.

   (Auth.: HAR §11-60.1-5, §11-60.1-204(g))

Section B. GHG Permit Conditions

1. Permit conditions specified in Attachment II – GHG, including provisions to limit maximum potential GHG emissions, are state-only enforceable requirements which are not federally enforceable under the federal Clean Air Act.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, 11-60.1-161; 40 CFR §70.6)[1]

2. The permittee shall comply with all applicable provisions of these conditions, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these provisions are detailed in the special conditions of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, 11-60.1-161)[1]

Section C. GHG Emission Limitations

1. GHG Emission Caps

   a. Each partnering facility shall not emit or cause to be emitted carbon dioxide equivalent (CO_2e) emissions in excess of the following individual caps, except as specified in Attachment II - GHG, Special Condition No. C.1.c.iv:

      i. For calendar year 2019, each partnering facility shall not exceed the following individual GHG emission caps:

Calendar Year 2019			
Generating Station	**CSP Permit No.**	**CO_2e Emission Cap[a]**	
		Metric Tons per Calendar Year	**Short Tons per Calendar Year**
AES Hawaii, LLC Cogeneration Plant	0087-02-C	1,534,598	1,691,605
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	227,906	251,223
Kalaeloa Partners, L.P. Cogeneration Plant	0214-01-C	993,198	1,094,813
HECO Campbell Industrial Park Generating Station	0548-01-C	48,752	53,740
HECO Honolulu Generating Station	0238-01-C	0	0
HECO Kahe Generating Station	0240-01-C	1,935,707	2,133,752
HECO Waiau Generating Station	0239-01-C	733,265	808,286
HELCO Kanoelehua-Hill Generating Station	0234-01-C	171,991	189,588
HELCO Keahole Generating Station	0007-01-C	248,043	273,421
HELCO Puna Generating Station	0235-01-C	64,666	71,282
MECO Kahului Generating Station	0232-01-C	140,281	154,633
MECO Maalaea Generating Station	0067-01-C	417,182	459,864
MECO Palaau Generating Station	0031-04-C	23,999	26,454

[a]Metric Tons = (0.90718474) x (Short Tons).

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ii. For calendar year 2020 and beyond, each partnering facility shall not exceed the following individual GHG emission caps, except as specified in Attachment II – GHG, Special Condition No. C.3:

Calendar Year 2020 and Beyond			
Generating Station	**CSP Permit No.**	**CO_2e Emission Cap[a]**	
		Metric Tons per Calendar Year	**Short Tons per Calendar Year**
AES Hawaii, LLC Cogeneration Plant	0087-02-C	1,281,442	1,412,548
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	139,433	153,699
Kalaeloa Partners, L.P. Cogeneration Plant	0214-01-C	1,056,486	1,164,577
HECO Campbell Industrial Park Generating Station	0548-01-C	112,041	123,504
HECO Honolulu Generating Station	0238-01-C	0	0
HECO Kahe Generating Station	0240-01-C	1,998,996	2,203,516
HECO Waiau Generating Station	0239-01-C	796,554	878,050
HELCO Kanoelehua-Hill Generating Station	0234-01-C	156,449	172,456
HELCO Keahole Generating Station	0007-01-C	219,727	242,208
HELCO Puna Generating Station	0235-01-C	28,800	31,747
MECO Kahului Generating Station	0232-01-C	140,281	154,633
MECO Maalaea Generating Station	0067-01-C	417,182	459,864
MECO Palaau Generating Station	0031-04-C	23,999	26,454

[a]Metric Tons = (0.90718474) x (Short Tons).

b. All partnering facilities shall not exceed the following combined emission caps:

i. For 2019, total combined CO_2e emissions in excess of 7,208,661 short tons (6,539,587 metric tons) per calendar year.
ii. For 2020 and beyond, CO_2e emissions in excess of 7,023,257 short tons (6,371,392 metric tons) per calendar year, except as specified in Attachment II – GHG, Special Condition No. C.3.

c. For purposes of the CO_2e emission limits in Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b:

i. The CO_2e emissions shall have the same meaning as that specified in HAR §11-60.1-1;
ii. In accordance with HAR §11-60.1-204(d)(6)(B), biogenic carbon dioxide (CO_2) emissions shall not be included when determining compliance with the emissions limit;
iii. The permittee shall be in compliance with the emissions limits by the end of 2019 and each calendar year thereafter;
iv. The permittee may exceed the emissions cap specified in Attachment II - GHG, Special Condition No. C.1.a, if the GHG emissions limit specified in Attachment II - GHG, Special Condition No. C.1.b is met; and

v. At no time shall the permittee exceed Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b simultaneously over a calendar year. For incidences when Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b, are exceeded simultaneously, emissions in excess of the total combined cap shall be allocated according to the following equation for compliance purposes:

$$X = XG\ \frac{(A - C)}{\sum_{A_i > C_i}(A_i - C_i)}$$

Where:

X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b, respectively.

XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap.

A = Actual GHG emissions from the affected facility.

C = GHG emissions cap for the affected facility.

$\sum_{Ai>ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-204)

2. GHG Emission Cap Revisions

a. The facility-wide GHG emissions cap may be re-evaluated and revised by the Department in accordance with HAR §11-60.1-204(h).
b. Any revision to the facility-wide GHG emissions cap shall be considered a significant modification subject to the application and review requirements of HAR §11-60.1-104. For each GHG emission cap revision, the Department may impose additional emission limits or requirements, or limit the time-frame allowed for the revised GHG emissions cap.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-204)

3. Alternate Operating Scenarios

The alternate operating scenario for the PGV facility shutdown due to volcanic activity on the island of Hawaii in 2018, shall remain in effect until an additional net energy generation of 26,883 MWh per month from the PGV facility is reached in any month of the year. The following shall apply to the individual and total combined alternate operating scenario GHG emission cap adjustments starting January 1, 2020, and for any subsequent year until these alternate operating scenarios no longer apply:

a. Attachment II – GHG, Special Condition No. C.3 no longer applies when:

$$NG_{PGV-R} \geq NG_{PGV2017}$$

Where:

$NG_{PGV2017}$ =	26,883	Net Generating capacity from the PGV facility in calendar year 2017 on an average monthly basis (MWh) preceding its shutdown.
NG_{PGV-R} =		Net Generation from the restored PGV facility (MWh per month)

b. The alternate scenario individual GHG emission cap adjustment for calendar year 2019 is 97,524 short tons for Hamakua Energy, LLC, 17,132 short tons for Kanoelehua-Hill Generating Station, 31,213 short tons for Keahole Generating Station, and 39,535 short tons for Puna Generating Station. Starting on January 1, 2020, and for any subsequent year, the alternate scenario GHG emissions individual cap adjustment for each of the foregoing island of Hawaii partnering facilities shall be calculated by adding one-twelfth (1/12) of the 2019 annual adjustment for each facility's individual GHG emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a.ii per month for the facilities from January 1 of that year. Monthly adjustments to the individual GHG emission caps shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

c. The PGV alternate scenario total combined cap adjustment for calendar year 2019 is 185,404 short tons. Starting on January 1, 2020, and for any subsequent year, the PGV alternate operating scenario total combined GHG emissions cap adjustment shall be calculated by adding one-twelfth (1/12) of the 2019 annual adjustment of 15,450 short tons to the total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b.ii per month from January 1 of that year. Monthly adjustments to the total combined GHG emissions cap shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

d. Monthly adjustments to the individual and total combined GHG emission caps shall be determined with the following equation:

$$AC = FAC/12$$

Where:

FAC = Full Adjustment to CO_2e caps (short tons – refer to table below)
AC = Monthly adjustment to GHG Emissions Caps

Generating Station	Full Adjustment to CO_2e Caps (Short Tons)	2020 CO_2e Cap (Short Tons)	FAC/12 (Short Tons)[b]
Hamakua Energy	97,524	153,699	8,127
Kanoelehua-Hill	17,132	172,456	1,428
Keahole	31,213	242,208	2,601
Puna	39,535	31,747	3,295
Combined	185,404	see note[a]	15,450

[a]Total combined CO_2e cap for all partnering facilities is 7,023,257 short tons.
[b]Monthly full CO_2e cap adjustment.

e. Individual GHG emission cap adjustments, affecting the total combined GHG emissions cap, shall only apply to partnering facilities on the island of Hawaii.
f. The permittee may exceed the adjusted individual GHG emissions cap as determined in Attachment II – GHG, Special Condition No. C.3.b, if the adjusted total combined GHG emission cap as determined in Attachment II – GHG, Special Condition No. C.3.c is met.
g. Alternate operating scenario records shall be maintained in accordance with Attachment II - GHG, Special Condition No. D.3.
h. The terms and conditions under each operating scenario shall meet all applicable requirements, including the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-204(h))

Section D. Monitoring and Record Keeping Requirements

1. GHG Emissions

For calculating CO_2e emissions to assess fees, determining compliance with the GHG emission caps, and quality assurance/quality control requirements, the permittee shall:

a. Monitor the CO_2 mass emissions data for the stationary source combustion units listed in Attachment II – GHG, Special Condition No. A.1, in accordance with 40 Code of Fderal Regulations (CFR) §98.34;
b. Estimate missing data in accordance with the applicable procedures in 40 CFR §98.35;
c. Determine the metric tons of CO_2, methane (CH_4), and nitrous oxide (N_2O) in accordance with 40 CFR §98.33;
d. For measuring CO_2 mass emissions from the boilers with the Tier 4 calculation methodology, use Environmental Protection Agency (EPA) Reference Method 2F during each relative accuracy test audit (RATA) performed to quality assure the continuous emissions monitoring (CEMS) exhaust flow meter of each boiler;
e. Correct the EPA Method 2F flow results obtained during each RATA with the established wall-effects adjustment factor (WAF);

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f. Conduct the CEMS exhaust flow meter RATA using the same number of traverse points as that used to determine the WAF;
g. Identify, at a minimum, in the RATA reports, the test results, test methods, test locations, parameters evaluated, CEMS analyzer descriptions, WAF values including the number of traverse points used to determine the WAF and the number of traverse points used for EPA Method 2F, boiler operating load (MMBtu/hr), and the types and rates of fuel combusted including the associated certificate and analysis, or equivalent, of the coal combusted;
h. Maintain records on the CEMS exhaust flow meter K-Factor(s) (flow correction multiplier and polynomial), WAF, and dilution ratio correction algorithm details for each boiler;
i. Calculate the GHG emissions, expressed in metric tons of CO_2e, using Equation A-1 of 40 CFR §98.2;
j. Convert the metric tons of CO_2e emissions to short tons for monitoring and annual emissions reporting, as applicable. For the conversion, one (1) short ton is equal to 0.90718474 metric tons;
k. Maintain the certificate of sampling and analysis, or equivalent, of the coal supplied that provides, at a minimum, the coal moisture content, ash content, and carbon content (dry ash free basis), date of receiving the coal shipment, and the amount of coal supplied (e.g., short tons, metric tons, long tons, etc.);
l. Maintain records on the short tons of limestone sorbent used for each boiler using measurements from a non-resetting weigh scale for the continuous and permanent recording of the amount of limestone fed to the boilers;
m. Provide total actual CO_2e emissions semi-annually to HECO in Item 1 of **Monitoring Report Form: GHG Emissions.** The monitoring report form, with Item 1 emissions data, shall be signed and dated by a responsible official; and
n. Report CO_2e emissions in accordance with Attachment II - GHG Special Condition No. E.4.

(Auth.: HAR §11-60.1-3, §11-60.1-90; §11-60.1-204d(6)(c); 40 CFR §98.2, §98.33, §98.34, §98.35, §98.6)

2. Records

All records, including support information, shall be maintained for **at least five (5) years** from the date of the monitoring sample, measurement, test, report, or applications. Support information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and be made available to the Department or authorized representative(s) upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

3. Alternate Operating Scenarios

a. The permittee shall contemporaneously with making a change from one operating scenario to another record in a log, the scenario under which it is operating.
b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

Section E. Notification and Reporting Requirements

1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively:

a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. Deviations

a. Except as specified in Attachment II - GHG, Special Condition No. E.2.b, the permittee shall report in writing **within five (5) working days** any deviations from permit requirements, including those attributed to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. Corrective actions may include a requirement for testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.
b. The permittee shall report, in writing, deviations from Attachment II – GHG, Special Condition No. C.1.c.v, the probable cause of such deviations, and any corrective actions or preventive measures taken. Corrective actions may include a requirement for testing, more frequent monitoring, or could trigger implementation of a corrective action plan. Reports shall be submitted **within sixty (60) days** following the end of each calendar year.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Compliance Certification

   a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. For making this certification for the partnering facility conditions in Attachment II – GHG, the permittee is relying on information provided by other partners that these partners independently certify. The compliance certification shall include, at a minimum, the following information:

      i. The identification of each term or condition of the permit that is the basis of the certification;
      ii. The compliance status;
      iii. Whether compliance was continuous or intermittent;
      iv. The methods used for determining the compliance status of the source currently and over the reporting period;
      v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
      vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
      vii. Any additional information as required by the Department, including information to determine compliance.

   b. The compliance certification shall be submitted **within sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
   c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

4. Monitoring Reports

   a. The permittee shall complete and submit **semi-annual** monitoring reports to the Department that provide the metric tons and short tons of CO_2e emitted by all partnering facilities, except that biogenic CO_2 shall be excluded from the total CO_2e emissions. All reports shall be submitted **within sixty (60) days after** the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31). The following enclosed form, or equivalent form, shall be used for reporting and shall be signed and dated by a responsible official:

      Monitoring Report Form: GHG Emissions

   b. For calendar year 2019, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2019 calendar year shall be used for reporting and shall be signed and dated by a responsible official.
   c. For calendar year 2020, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit or **within sixty (60) days** after the end of the semi-annual calendar period, whichever is later. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2020 calendar year shall be used for reporting and shall be signed and dated by a responsible official.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

Section F. Agency Notification

Any document (including reports) required to be submitted by this permit shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1]The citations to the CFR identified under a particular condition indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2]The citations to the State Implementation Plan (SIP) identified under a particular condition indicate that the permit condition complies with the specified provision(s) of the SIP.

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ATTACHMENT III: ANNUAL FEE REQUIREMENTS
COVERED SOURCE PERMIT NO. 0087-02-C

Amended Date: DATE **Expiration Date: April 15, 2019**
(Expiration Date to be Revised Upon Permit Renewal)

The following requirements for the submittal of annual fees are established pursuant to HAR, Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1, be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1.

1. Annual fees shall be paid in full:

   a. Within **one hundred twenty (120) days** after the end of each calendar year; and
   b. Within **thirty (30) days** after the permanent discontinuance of the covered source.

2. The annual fees shall be determined and submitted in accordance with HAR, Chapter 11-60.1, Subchapter 6.

3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and submitted on forms furnished by the Department.

4. The annual fees and the emission data shall be mailed to:

State of Hawaii
Clean Air Branch
2827 Waimano Home Road, #130
Pearl City, HI 96782

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MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0087-02-C

Amended Date: DATE **Expiration Date: April 15, 2019**
(Expiration Date to be Revised Upon Permit Renewal)

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually.

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________
Facility Name: ______________________________
Location: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. In making this certification for the partnering facility conditions in Items 2 and 3 of this form, I am relying on information provided by other partners that these partners independently certify.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

1. Report the CO_2e emitted by the AES Hawaii, LLC, cogeneration plant during each reporting period for purposes of the facility's individual GHG emissions cap:

Emission Year Reporting For ____________					
Reporting Period	AES Hawaii, LLC Emissions (Metric Tons of CO_2e)			AES Hawaii, LLC Emissions (Total CO_2e)	
	CO_2 (Non-Biogenic)	CH_4	N_2O	Metric Tons	Short Tons
January 1 – June 30 (1st Semi-Annual Period)					
July 1 – December 31 (2nd Semi-Annual Period)					
Total Emissions →					

Provide the CO_2e emitted by the AES Hawaii, LLC, cogeneration plant in Item 1 above to HECO during each reporting period for purposes of calculating the total combined GHG emissions from the partnering facilities.

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MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0087-02-C
(CONTINUED, PAGE 2 OF 3)

Amended Date: **DATE** **Expiration Date:** **April 15, 2019**
(Expiration Date to be Revised Upon Permit Renewal)

2. Report the total combined CO_2e emitted by all partnering facilities during each reporting period for purposes of the total combined GHG emissions cap for these facilities:

Emission Year Reporting For__________________					
Reporting Period	Total Combined Emissions from All Partnering Facilities (Metric Tons of CO_2e)			Total CO_2e	
	CO_2 (Non-Biogenic)	CH_4	N_2O	Metric Tons	Short Tons
January 1 – June 30 (1st Semi-Annual Period)					
July 1 – December 31 (2nd Semi-Annual Period)					
Total Emissions →					

3. For incidences when the individual cap for the AES Hawaii, LLC, cogeneration plant and total combined cap for all partnering facilities is exceeded, report the emissions in excess of the total combined cap using the following equation:

$$X = XG \frac{(A-C)}{\sum_{A_i > C_i}(A_i - C_i)} = \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_$$

Where:

X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b, respectively.
XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap.
A = Actual GHG emissions from the affected facility.
C = GHG emissions cap for the affected facility.
$\sum_{Ai>ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0087-02-C
(CONTINUED, PAGE 3 OF 3)

Amended Date: DATE **Expiration Date: April 15, 2019**
(Expiration Date to be Revised Upon Permit Renewal)

4. Report any changes to CEMS flow rate corrections initially applied to the CEMS setup for each boiler to correct bias high readings:

Emission Year Reporting For___________________					
Correction Description	Initial Setup		CEMS Setup Changes		Reason for Change in CEMS Setup
	Boiler		Boiler		
	A	B	A	B	
CEMS K-Factor[a]	0.76	0.76			
WAF Factor	0.9147	0.9148			

[a]Also referred to as a flow data multiplier

5. Report on another sheet, any changes to the CEMS dilution ratio algorithm initially applied to the CEMS setup of Boiler A to correct bias high readings.

6. Report on another sheet, any changes to the CEMS dilution ratio corrections initially applied to the CEMS setup of Boiler B to correct bias high readings.

7. Submit the amount of limestone sorbent consumed for each semi-annual reporting period:

Emissions Year Reporting For _________________		
Reporting Period	List Type(s) of Sorbent(s)	Consumption (Short Tons)
January 1 – June 30 (1st Semi-annual Period)		
July 1 – December 31 (2nd Semi-annual Period)		
Total Amount of Sorbent Consumed →		

8. Provide a copy of the certificate of sampling and analysis, or equivalent, for all coal burned during each semi-annual reporting period.

DRAFT REVIEW SUMMARY

PERMIT APPLICATION REVIEW
GREENHOUSE GAS (GHG) EMISSION REDUCTION PLAN
Covered Source Permit (CSP) No. 0087-02-C
Application for Significant Permit Modification No. 0087-09

Applicant: AES Hawaii, LLC
Facility: 203 MW Coal-Fired Cogeneration Plant
Located At: 91-086 Kaomi Loop, Kapolei, Oahu
UTM Coordinates: 2,355,920.4 meters N and 592,473.8 meters E
Mailing Address: 91-086 Kaomi Loop
Kapolei, Hawaii 96707-1883

Responsible Official: Steven Barnoski
Plant Manager
AES Hawaii, LLC
(808) 682-3419
Steven.barnoski@aes.com

Contact: Priya Kumar
Environmental Coordinator
AES Hawaii, LLC
(808) 682-3409
Priya.kumar@aes.com

Background

AES Hawaii, LLC (AES) has applied for a significant modification to CSP No. 0087-02-C for its cogeneration plant to incorporate facility-wide GHG emission caps as defined in Hawaii Administrative Rules (HAR) §11-60.1-202. Site specific GHG emission limits were established based on the greenhouse gas (GHG) emission reduction plan received on December 1, 2016, March 5, 2018, October 30, 2018 and July 30, 2019, and the additional information on January 23, 2020, February 14 , 2020, April 2, 2020, May 22, 2020, and June 9, 2020 from Hawaiian Electric submitted on behalf of the partnership for cap adjustments. Updates include proposed cap adjustments due to complications arising from the shutdown of a geothermal energy plant and allocation of emissions for reducing the individual GHG emissions cap for the AES cogeneration plant by 16%. Another update are alternate operating scenarios in the event delays are encountered for restoring operation of the Puna Geothermal Venture (PGV) facility on the island of Hawaii after its shutdown in 2018 due to volcanic activity. Affected facilities subject to GHG reductions are existing stationary sources with maximum potential carbon dioxide equivalent (CO_2e) emissions (biogenic plus non-biogenic) equal to or greater than 100,000 short tons per year. The requirements to cap GHG emissions are specified in HAR, Subchapter 11, pursuant to Hawaii Act 234, 2007, which directed the Department of Health to develop rules for regulating GHGs. Partnering will be used as a measure to comply with the caps in accordance with HAR §11-60.1-204(d)(6)(A).

AES is partnering with affected facilities of two (2) independent power producers (IPPs) and ten (10) affected plants from the Hawaiian Electric Companies to allow flexibility in dispatching generating units for meeting requirements to cap GHGs. The IPP affected facilities are cogeneration plants owned and operated by AES, Hamakua Energy, LLC, and Kalaeloa Partners, L.P. Hawaiian Electric Companies' affected plants include those from Hawaiian Electric Company, Inc. (HECO), Hawaii Electric Light Company, Inc. (HELCO), and Maui Electric Company, Limited (MECO). Flexibility for dispatching units is a concern in the event a facility has unplanned outages or there is reduced output from renewable generation such as solar (e.g., due to extended cloudy or rainy weather) or geothermal (e.g., deactivation of 38-megawatt (MW) geothermal plant due to volcanic activity on Hawaii Island).

The table below lists the affected facilities that have mutually agreed to partner.

Partnering Facilities[a]			
IPP Plants			
Facility	**Permit No.**	**Description**	**Island**
AES Hawaii, LLC Cogeneration Plant	CSP No. 0087-02-C	203 MW Coal Fired Generation Plant Consisting of Two (2) CFB Boilers and Two (2) Limestone Dryers. The Boilers are Each Equipped with Lime Injection, SNCR, and a Baghouse.	Oahu
Hamakua Energy, LLC Cogeneration Plant	CSP No. 0243-01-C	65 MW Cogeneration Facility Consisting of Two (2) 23 MW CTs with Water Injection and SCR, Two (2) HRSGs, 1,250 kW Black Start DEG, and 19 MW Steam Turbine.	Hawaii
Kalaeloa Partners, L.P. Cogeneration Plant	CSP No. 0214-01-C	Two (2) 86 MW CTs with Steam Injection, Two (2) HRSGs, and 51 MW Steam Turbine.	Oahu
HECO Plants			
Facility	**Permit No.**	**Description**	**Island**
Campbell Industrial Park Generating Station	CSP No. 0548-01-C	135 MW CT with Water Injection and Two (2) 2,250 kW Black Start DEGs.	Oahu
Honolulu Power Plant	CSP No. 0238-01-C	56 MW Boiler and 57 MW Boiler.	Oahu
Kahe Power Plant	CSP No. 0240-01-C	Six (6) Boilers (92 MW to 142 MW) and Two (2) 2.5 MW Black Start DEGs. A 142 MW Boiler is Equipped with Low NO_x Burners.	Oahu
Waiau Power Plant	CSP No. 0239-01-C	Six (6) Boilers (49 MW to 92 MW), 50 MW CT and 52 MW CT.	Oahu
HELCO Plants			
Facility	**Permit No.**	**Description**	**Island**
Kanoelehua-Hill Power Plant	CSP No. 0234-01-C	14.1 MW Boiler, 23 MW Boiler, 11.6 MW CT, 2.0 MW DEG with Oxidation Catalyst, and Three (3) 2.75 MW DEGs with Oxidation Catalyst.	Hawaii
Keahole Power Plant	CSP No. 0007-01-C	Two (2) 20 MW CTs with Water Injection and SCR, Two (2) HRSGs, Three (3) 2.5 MW DEGs with FITR and Oxidation Catalyst, 500 kW Black Start DEG, 16 MW Steam Turbine, and 18 MW CT with Water Injection.	Hawaii
Puna Power Plant	CSP No. 0235-01-C	20 MW CT with water injection, 1,250 hp Black Start DEG, and 15.5 MW Boiler with Multicyclone Dust Collector.	Hawaii
MECO Plants			
Facility	**Permit No.**	**Description**	**Island**
Kahului Power Plant	CSP No. 0232-01-C	Two (2) 5.0 MW Boilers, One (1) 11.5 MW Boiler, and 12.5 MW Boiler.	Maui
Maalaea Power Plant	CSP No. 0067-01-C	Three (3) 2.5 MW DEGs with Oxidation Catalyst and Lube Oil Separator, Six (6) 5.6 MW DEGs with Oxidation Catalyst and Open Crankcase Filtration System, Two (2) 12.5 MW DEGs with Oxidation Catalyst and Open Crankcase Filtration System, Two (2) 12.5 MW DEGs with Oxidation Catalyst, Crankcase Filtration System, and FITR, Two (2) 20 MW CTs with Water Injection, Two (2) HRSGs, 18 MW Steam Turbine, Two (2) 20 MW CTs with Water Injection, HRSG, Two (2) 2.5 MW DEGs with Oxidation Catalyst, Lube Oil Separator, and FITR, and 600 kW Black Start DEG.	Maui
Palaau Power Plant	CSP No. 0031-04-C	Two (2) 1.25 MW DEGs with FITR and Oxidation Catalyst, Four (4) 1.0 MW DEGs with FITR and Oxidation Catalyst, Three (3) 2.2 MW DEGs with FITR, Oxidation Catalyst, and intake cooling, and 2.0 MW CT.	Molokai

[a]CFB-circulating fluidized bed, NO_x-nitrogen oxide, CT-combustion turbine, DEG-diesel engine generator, FITR-fuel injection timing retard, HRSG-heat recovery steam generator, kW-kilowatt, MW-megawatt, SCR-selective catalytic reduction, and SNCR-selective non-catalytic reduction.

The GHG emission reduction plan for the AES cogeneration plant was used to establish the following for the significant permit modification to CSP No. 0087-02-C to incorporate GHG emission caps:

1. A total combined limit on CO_2e emissions from affected facilities operated by HECO, HELCO, MECO, and three (3) IPPs not to exceed 7,023,257 short tons (6,371,392 metric tons) per calendar year, except for calendar year 2019;
2. A total combined cap on CO_2e emissions from affected facilities operated by HECO, HELCO, MECO, and three (3) IPPs not to exceed 7,208,661 short tons (6,539,587 metric tons) for calendar year 2019;
3. Individual facility-wide cap on CO_2e emissions from the AES cogeneration plant for 2019 not to exceed 1,691,605 short tons (1,534,598 metric tons) per calendar year that will not apply as long as the total combined cap among partnering facilities is met;
4. Individual facility-wide cap on CO_2e emissions from the AES's cogeneration plant for 2020 and beyond not to exceed 1,412,548 short tons (1,281,442 metric tons) per calendar year that will not apply as long as the total combined cap among partnering facilities is met; and
5. An equation allocating GHG emissions in excess of the total combined cap for facilities violating the individual and total combined GHG emission caps.

The IPPs have separate permits specifying individual and total combined GHG caps for all partnering facilities. Any GHG emissions cap revision will require each IPP to submit a single permit application for significant modification since caps have been incorporated separately into each affected facility's permit.

For HECO, HELCO, and MECO affected facilities, CSP No. 0548-01-C for Campbell Industrial Park Generating Station will be the main permit specifying individual and total combined GHG emission caps that will be referenced in the other Hawaiian Electric Companies' permits. This will enable modification of a single permit if CO_2e caps need to be revised and reduce the burden of modifying all of Hawaiian Electric Companies' permits had the caps been incorporated separately into each facility's permit.

AES's cogeneration plant utilizes clean coal technology (eg., lime injection to control sulfur dioxide (SO_2), SNCR for NO_X control, baghouses for particulate control, etc.) to generate steam and electricity. According to the GHG emission reduction plan, AES is the single largest power generator on Oahu and provides 20% of the island's electrical energy demand. Also, AES sells electricity to HECO under a 30-year power purchase agreement (PPA) that expires in October of 2022.

An opportunity for public comment on the draft GHG emissions reduction plan and revised permit for AES's cogenerating plant will be provided in accordance with HAR §11-60.1-205.

The Standard Industrial Classification Code (SICC) for this facility is 4911 – Electric Services.

Permitted Equipment Subject to GHG Emissions Cap

The following permitted boilers and associated appurtenances are subject to GHG emission reductions specified in Subchapter 11 of the HAR for AES's cogeneration plant:

Equipment	Manufacturer	Capacity[a]
Circulating Fluidized Bed Boiler A with Limestone Injection	Alstrom Pyropower Corporation	2,150 MMBtu/hr
Circulating Fluidized Bed Boiler B with Limestone Injection	Alstrom Pyropower Corporation	

[a]Total combined capacity based on a 215,000 lb/hr total combined coal feed rate to boilers and 10,000 Btu/lb heating value based on information supplied for the initial PSD application as follows: (215,000 lb/hr)(10,000 Btu/lb) = 2,150 MMBtu/hr.

The following permitted limestone dryers and associated appurtenances are subject to GHG emission reductions specified in Subchapter 11 of the HAR for the AES cogeneration plant:

Equipment	Manufacturer	Capacity
Limestone Dryer 1A	Micro Powder Systems	4.75 MMBtu/hr
Limestone Dryer 1B	Micro Powder Systems	4.75 MMBtu/hr

Permitted Equipment/Processes Not Subject to GHG Emissions Cap

The following permitted cooling tower and other permitted equipment for coal processing, ash handling, and limestone processing are not subject to GHG emission reductions specified in HAR Subchapter 11 because this equipment does not emit GHGs or is below the 3,500 ton per year (TPY) permitting threshold specified in HAR §11-60.1-82(f)(7).

Equipment/Process	Description
Cooling Tower	GEA Integrated Cooling Technologies, Inc., Five-Cell Cooling Tower with Fiberglass Counter Flow and Maximum Water Circulating Rate of 104,000 gal/min and Maximum Drift Rate of 0.02%.
275 TPY Coal Processing	Overland Coal Conveyor, Two (2) Lowering Wells, Four (4) Coal Conveyors, 275 TPY Coal Crusher, Four (4) Coal Storage Silos, and Two (2) Mikro-Pulsaire Baghouses.
Ash Handling	Fly Ash Reinjection Surge Hopper, Bed Ash Storage Hopper, Fly Ash Silo, Bed Ash Silo, and Conditioned Ash Mixer.
Limestone Processing	Limestone Storage Hopper with Mikro-Pulsaire Baghouse (Model No. 100S-8-20 "C'), Two (2) 22 TPH Micron Powder Systems Each with 22 Ton per Hour Limestone Feeder, Mikro Pulverizer (Model No. 300 ACM), Mikro-Pulsaire Baghouse (Model No. 420S-10-50 "C"), and Conveyors.

The following permitted storage tank is not subject to GHG emission reductions specified in HAR Subchapter 11 because GHG emissions reporting under 40 Code of Federal Regulations (CFR) Part 98 is not required for this tank. Also, GHG emissions from this tank are below the 3,500 TPY CO_2e permitting threshold specified in HAR §11-60.1-82(f)(7), assuming all volatile organic compound (VOC) emissions are methane (CH_4) with a global warming potential (GWP) of 25.

Tank Number [a,b]	Volume (gallons)	Tank Description
Fuel Oil No.2 Storage Tank	60,000	Vertical Fixed Roof Tank

[a]Hawaii Act 234, 2007 amended the Hawaii Revised Statutes, §342B-B, to require an endeavor to make state emission reporting requirements consistent with international, federal, and other state's GHG reporting requirements. The AES cogeneration plant is subject to 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting, Subpart C – General Fuel Combustion Sources. Storage tanks do not meet the definition of the source category specified in §98.30 of this subpart. Therefore, the above permitted storage tank was excluded from GHG reporting and emission reduction requirements specified in HAR Chapter 11-60.1, Subchapter 11.

[b]If all VOCs emitted from this tank were methane, maximum potential GHG emissions would be (ton VOC/year)(GWP for methane of 25)= (ton CH_4/yr)(25) = 560 TPY CO_2e of GHGs. This is below the 3,500 CO_2e permitting threshold specified in HAR §11-60.1-82(f)(7). Tank VOC emissions are based on estimates in permit application review No. 0087-07 indicating the total VOC emissions from this tank are 36.72 pounds per year for storing fuel oil No. 2.

Air Pollution Controls

CFB Boilers

1. **SNCR with Ammonia Injection (70% NO_x reduction)**

   NO_x emissions are controlled with SNCR using ammonia injection, or an alternative reducing agent like urea, at the inlet to the hot cyclone. This process breaks down the NO_x into water and atmospheric nitrogen. The SNCR system with Ammonia/Urea Injection (Thermal DeNO_x), designed and manufactured by Alhstrom Pyropower, can meet the permitted NO_x emission limits. The optimum combustion temperatures for the efficient use of ammonia injection are 1,400 to 1,900 degrees Fahrenheit. Ammonia injection is typically not used when the temperatures are below 1,400 degrees.

2. **Limestone Injection (75% to 90% SO_2 reduction)**

   SO_2 emissions are controlled with the injection of pulverized limestone into the combustion zone. The SO_2 is absorbed by the limestone and forms gypsum. The heavier particles fall to a hopper while the lighter particles are carried by the flue gas and then captured by the baghouse. Pursuant to PSD HI 88-02 review, 90% reduction can be met when high sulfur fuel is used.

3. **Good Combustion**

   Proper boiler operation and good combustion practices will help control particulate, carbon monoxide (CO), and VOC emissions. Also, low temperature-staged combustion design of the boilers reduces NO_x emissions. In addition, SO_2 is controlled by using coal with a maximum sulfur content of 1.5% by weight.

4. **Clean Coal Technology**

As indicated by AES, CFB technology for the boilers is considered a clean coal technology because of the nature of its combustion process. In CFBs, crushed coal and pulverized limestone (for SO_2 capture) are fed into a bed of ash, then made highly mobile by a high velocity stream of preheated air. Internal circulation of solids provides longer residence time for the fuel and limestone, resulting in good combustion and improved sulfur capture. The air is fed into the combustor at two (2) levels. This staged combustion and the low combustion temperature reduce NO_X. Additional control is from SNCR using ammonia injection. The combustion gas from the combustor flows upward with entrained solids that are separated from the combustion gas in a cyclone that continuously returns these solids to the combustion chamber by a recycle loop. Particulate left in the flue gas is controlled by baghouses servicing each boiler.

Baghouses (99.99% PM/PM_{10} reduction)

Particulate and opacity are controlled using baghouses shown in the table below.

Emissions Unit	Baghouse (No./Manufacturer/Model)	Operating Pressure
Boilers *	2/Asea Brown Boveri/ Flakt Model 2	1-9" H_2O
Limestone Driers/Crushers	2/Mikro-Pulsaire/420S-10-50 “C”	1-7" H_2O
Limestone Feeders **	4/AEROPULSE/SB-9-4-H-N	1-7" H_2O
Limestone Storage Hoppers **	1/Mikro-Pulsaire/100-S-8-20 “C”	1-7" H_2O
Coal Crusher	1/Mikro-Pulsaire/64S-8-40 “C”	1-7" H_2O
Coal Storage Silos and Coal Conveyor 4 **	1/Mikro-Pulsaire/100S-8-20 “C”	1-7" H_2O
Fly Ash Silo **	1/Mikro-Pulsaire/64S-8-20 TRH “B”	1-7" H_2O
Fly Ash Reinjection **	1/Mikro-Pulsaire/25S-8-30 “B”	1-7" H_2O
Bed Ash Silo **	1/Mikro-Pulsaire/64S-8-20 TRH “B”	1-7" H_2O
Bed Ash Hopper **	1/Mikro-Pulsaire/25S-8-30 “B”	1-7" H_2O
Ash Mixer **	1/Dalamatic Unimaster/DLMV20F	1-7" H_2O

* Hot exhaust gases from each boiler pass through individual (each boiler has its own baghouse) fabric filter baghouse. After leaving the baghouse, exhaust gases from both boilers join into a common stack exiting to the atmosphere.

**Baghouses that are insignificant since estimated emissions are small.

Fugitive Dust Suppression

Fugitive dust is controlled using the methods shown in the table below throughout the facility:

Emissions Unit	Control	Expected
Coal Processing:		
Conveyors	covers	70%
Lowering wells	partial enclosures	75%
Active storage piles and mobile equipment	water	50%

Emissions Unit	Control	Expected
Limestone Processing:		
Conveyors	covers	70%
Active storage piles and mobile equipment	water	50%
Ash Handling:		
Fly ash silo	mechanical pre-separator/telescopic chute	97%
Bed ash silo	mechanical pre-separator/telescopic chute	97%
Aggregate ash mixer	partial enclosure	85%
Handling of aggregate ash	water	50-90%

Applicable Requirements

State Requirements:

Hawaii Administrative Rules

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 1	General Requirements
HAR 11-60.1-1	Definitions
Subchapter 2	General Prohibitions
HAR 11-60.1-31	Applicability
HAR 11-60.1-32	Visible Emissions
HAR 11-60.1-38	Sulfur Oxides from Fuel Combustion
HAR 11-60.1-39	Storage of Volatile Organic Compounds
Subchapter 5	Covered Sources
HAR 11-60.1-81	Definitions
HAR 11-60.1-104	Applications for Significant Modification
Subchapter 6	Fees for Covered Sources, Noncovered Sources, & Agricultural Burning
HAR 11-60.1-111	Definitions
HAR 11-60.1-112	General Fee Provisions for Covered Sources
HAR 11-60.1-113	Application Fees for Covered Sources
HAR 11-60.1-114	Annual Fees for Covered Sources
HAR 11-60.1-115	Basis of Annual Fees for Covered Sources
Subchapter 8	Standards of Performance for Stationary Sources
Subchapter 9	Maximum Achievable Control Technology (MACT) Emission Standards
Subchapter 11	Greenhouse Gas Emissions

HAR Chapter 11-60.1, Subchapter 11, §11-60.1-204 GHG Emission Reduction Plan.

1. Applicability to Subchapter 11 pursuant to HAR §11-60.1-204(a).

   HAR §11-60.1-204 is applicable to the AES cogeneration plant since this facility is a permitted covered source with potential CO_2e emissions (biogenic plus non-biogenic) equal to or above 100,000 short tons per year.

2. Baseline Emission Rate and Cap.

Pursuant to HAR §11-60.1-204(b) and (c), AES is proposing to establish annual facility-wide GHG emissions caps for its cogeneration plant. As provisioned in HAR §11-60.1-204(d)(6)(A), AES is proposing to combine its facility's GHG emissions cap with other GHG caps established for partnering facilities to leverage emission reductions.

AES uses a continuous emissions monitoring system (CEMS) to monitor carbon dioxide (CO_2) emissions from its boilers, however, in 2010 the CEMS was not setup to use the stack exhaust flow monitor for measuring CO_2 emissions. Therefore, the CO_2e emissions from Boilers A and B for establishing the facility's 2010 GHG baseline level were based on calculations using fuel data from 2010.

According to AES, the stack exhaust flow monitor has historically over-reported flow which would increase (greater than 20%) the emissions of CO_2 reported. As indicated by AES, annual GHG emissions from years 2011 to 2015, based on fuel data for the boilers, were recalculated manually using CEMS stack flow data and resubmitted to EPA. However, since CEMS flow was not adjusted, GHG emissions reported for these years is bias high.

In 2016, AES performed a CEMS audit which found the current system to over-report boiler exhaust flow since there is no coefficient in the CEMS setup to correlate response of the system to test methods or algorithm to correct for gas molecular weight and pressure variations. Calendar year 2018 will be the the first year that bias high CO_2 readings are corrected in the CEMS data for reporting GHG emissions.

As indicated in an October 4, 2017, RMB Consulting & Research, Inc., Memorandum to AES, CEMS adjustments were completed to implement the following corrections:

a. Made software modifications to incorporate a correction factor of 0.76 to the CEMS exhaust flow monitor setup on each boiler that adjust bias high CO_2 readings due to wall effects from rectangular ducts. The 0.76 CEMS exhaust flow monitor correction factor was determined using EPA reference Test Method 2F in conjunction with Conditional Test Method 041 (CTM-041);
b. Established a wall effects adjustment factor (WAF) using CTM-041 test results that will be applied to each CEMS exhaust flow monitor performance evaluation and calibration check with EPA Method 2F, since CTM-041 is a one-time test that will not be used with Method 2F to check the CEMS exhaust flow monitors in future performance evaluations. The WAFs for Boilers A and B were determined to be 0.9147 and 0.9148, respectively, based on results from the 2016 CEMS audit; and

c. Made software modifications to incorporate the following dilution ratio correction algorithm:

$$MW = 28 + 0.16\,(\%CO_2) - K_1 \begin{bmatrix} -0.836 \\ +\ 0.10836\,(\%H_2O) \\ +\ 0.00836\,(\%CO_2)\dfrac{F}{F_c} \end{bmatrix}$$

$MW = Molecular\ wight\ of\ the\ sample\ (prior\ to\ dilution)$

$\%CO_2 = Flue\ gas\ (or\ calibration\ gas)\ CO_2\ concentration$

$\%H_2O = Flue\ gas\ moisture\ concentration$

$K_1 = Operating\ mode\ variable/switch$

$(1 = normal\ sampling;\ 0 = calibration, linearity\ or\ maintenance)$

$F = F\text{-}factor\ (9780\ dscf/MMBtu\ for\ bitumous\ coal)$

$F_c = F_c\text{-}factor\ (1800\ scf\ CO_2/MMBtu\ for\ bitumous\ coal)$

AES's 2010 CO_2e baseline level of 1,681,605 tons per year was established using 2010 GWPs and fuel data. In 2014, the GWPs increased from 21 to 25 for CH_4 and decreased from 310 to 298 for N_2O. If AES had used the 2014 GWPs, slightly higher total CO_2e emissions would result.

To determine the 2010 baseline, AES used a Tier 3 methodology for the coal-fired boilers. Note that the "Dry, Ash Free" coal carbon content from analysis of the coal received must be used to determine emissions. It was found for 2010, that the average "As Received" carbon content was about twenty-four percent (24%) less than the "Dry, Ash Fee" coal carbon content. Also, the "Fixed Carbon" carbon content used in 2013 was incorrect since the fixed carbon only represents the carbon that will be left after driving off volatile matter from the coal. The appropriate value to use is the ultimate coal carbon content on an "As Received"/"As Fired" basis which includes the fixed and volatile carbon.

For review of AES's proposed facility-wide baseline GHG emissions level of 1,681,605 tons per year, the Department of Health Clean Air Branch (CAB) requested and received additional coal shipment information. The CAB's review found the 1,681,605 CO_2e emissions level to be well supported by the available fuel data. The CAB's estimate of 2010 GHG emissions was 1,686,648 tons per year which is about 0.3% higher than AES's proposed baseline value. The baseline proposed by AES is slightly, though insignificantly, conservative. The CAB, therefore, found AES's 1,681,605 CO_2e baseline level acceptable for establishing the GHG emissions cap.

Partnering facilities used 2010 as the baseline year to establish the cap, except for the Kalaeloa Partners, L.P Cogeneration Plant which used 2009 for its baseline because year 2010 was deemed unrepresentative due to an overhaul of this facility's steam turbine generator.

Each facility may exceed its individual cap as long as the total combined cap is met.

During the public comment period held from April 16, 2019 to May 15, 2019 to consider draft permits for the partnering facilities, both the Hawaiian Electric Companies and Hamakua Energy requested a temporary adjustment to the collective partnership GHG emissions cap. The Hawaiian Electric Companies (HECO) stated that the loss of renewable energy from PGV on Hawaii Island and the delay of new renewable energy projects planned for 2019, for reasons outside the direct control of the companies, has eliminated the additional compliance margin anticipated and relied upon in the GHG emission calculations. As indicated by the Hawaiian Electric Companies, the PGV plant was shut down in May 2018 due to the Kilauea eruption. Also, lava destroyed the Puna complex substation, the adjacent warehouse, and covered a few of PGV's geothermal wells, as well as cut off access to the PGV power plant. HECO, ultimately requested a 185,404 ton increase to the original partnership GHG emissions cap due to the loss of PGV for the entire 2019 operating year. This adjustment is documented in HECO's July 26, 2019 greenhouse gas emissions reduction plan.

According to HECO's February 14, 2020 correspondence, although a substantial amount of renewable energy was added, other renewable energy projects for 2019 and 2020 have been delayed until 2021. Preliminary GHG emissions of the partnership for calendar year 2019 are estimated to be 7,103,530 tons per year. This level exceeds the overall partnership GHG emissions cap of 7,023,258 tons per year that results in a 16% reduction of GHG emissions from the total combined baseline emissions level.

Upon incorporating the temporary increase requested in HECO's February 14, 2020 correspondence, the CAB returned the revised draft permits to HECO and the partnering IPPs for another review on March 18, 2020. In April 2, 2020 correspondence, HECO requested the CAB to consider a provision in the permits that allows the 2020 PGV allowance to be increased to the 2019 level adjusted for the loss of PGV in the event the PGV plant implementation is delayed until later in 2020; and additionally allow for the 2019 level adjusted for the loss of PGV to be continued into 2021 if implementation is delayed into 2021. HECO, AES Hawaii, LLC, and Kalaeloa Partners, L.P. also requested that the CAB clarify that no penalties could be asserted for that period given that GHG levels for 2019 are already documented and the permit will be approved after year end 2019.

To address concerns after a public hearing on September 26, 2019 and second public comment period from August 14, 2019 to September 27, 2019, HECO stated in a May 22, 2020 email that AES Hawaii, LLC has agreed to reduce its individual GHG emissions cap by 16% from its baseline emissions level. It was also HECO's understanding that PGV will not likely return to its level of pre-volcanic service by the end of 2020.

Recognizing the magnitude of legal uncertainties, an alternate operating scenario was incorporated into permits to address HECO's concerns on the delay in restoring operation of the PGV facility. The modification for CSP 0548-01-C was redrafted and returned to HECO for review on May 29, 2020.

The following provisions in the HAR allow the GHG emissions cap to be adjusted for events that are beyond the control of the owner or operator of an affected facility:

a. HAR §11-60.1-204(h)(4) allows the facility-wide GHG emissions cap to be re-evaluated and revised if renewable energy producers cease operations or fail to meet contractual obligations with the affected source, and there are no other reasonable alternatives.

b. HAR §11-60.1-204(h)(5) allows the facility-wide GHG emissions cap to be re-evaluated and revised when there are unforeseen events beyond the control of the permittee, resulting in long-term or temporary emission changes, whereby maintenance of the GHG emissions cap would be detrimental to the health and welfare of the public.

Based on the recent unforeseen events, the proposed revision to the facility-wide emissions cap for calendar year 2019 and the alternate operating scenario to address the delay in restoring operation to the PGV facility are considered to be within the provisions of HAR §11-60.1-204(h).

Pursuant to HAR §11-60.1-204(h)(4) and HAR §11-60.1-204(h)(5), CAB has agreed to temporarily adjust the GHG emissions cap for calendar year 2019 due to the PGV shutdown. Calculations to reallocate emissions for facilities on Hawaii Island were provided by the Hawaiian Electric Companies and updated on July 7, 2019 with lower numbers. For the adjustment, HECO determined the difference in emissions between electric plants on the Big Island operating with and without PGV. Emissions with PGV were based on 2017 numbers from EPA's electronic Greenhouse Reporting Tool (e-GGRT). Since the PGV plant shut down in May 2018, GHG emissions without PGV were based on twelve (12) months of fuel data from Hawaii Island electric plants operating from the beginning of July 2018 to the end of June 2019. The following tables provide results from HECOs evaluation to determine extra yearly GHG emissions from fossil fuel fired electric plants without renewable energy from PGV:

Big Island Plant GHG Emissions				
Big Island Plant	GHG Emissions (tons)			
	2017 e-GGRT	2018 Jul-Dec	2019 Jan-Jun	July 2018- June 2019
Hamakua Energy, LLC	98,962	112,722	126,252	238,974
HELCO Kanoelehua-Hill	193,103	90,662	89,683	180,345
HELCO Keahole	243,346	144,943	115,147	260,090
HELCO Puna	26,400	34,188	33,618	67,806
Total→	561,811	382,515	364,700	747,215

GHG Emissions Cap Adjustment for PGV Shutdown		
GHG Emissions (tons)		
2017 e-GGRT	July 2018- June 2019	Cap Adjustment (July 2018 – June 2019) Minus (2017 e-GGRT)
561,811	747,215	185,404

Individual GHG Emissions Caps for PGV Shutdown			
Big Island Plant	GHG Cap (tons)	Temporary GHG Cap (tons)	
	July 26, 2019 Greenhouse Gas Emission Reduction Plan (Page A-1)	Adjustment	CAP After PGV Shutdown
Hamakua Energy, LLC	153,699	97,524	251,223
HELCO Kanoelehua-Hill	172,456	17,132	189,588
HELCO Keahole	242,208	31,213	273,421
HELCO Puna	31,747	39,535	71,282
	Total→	185,404	785,514

The CAB has agreed to revise the permits to temporarily adjust individual and total combined GHG emission caps for calendar year 2019 as a result of the PVG shutdown. The GHG emission cap adjustment for calendar year 2019 adds 185,404 short tons per year of GHG emissions to the original total combined cap referenced in the July 26, 2019 greenhouse gas emission reduction plan with PGV in operation. The adjustment is the extra amount of GHG emissions that would result from fossil fuel combustion to replace renewable energy provided by PGV that is distributed to partnering facilities on the island of Hawaii that include Hamakua Energy, LLC, Kanoelehua-Hill Generating Station, Keahole Generating Station, and Puna Generating Station. Temporary adjustments to the caps are as follows for the 2019 emission year:

2019 Temporary CO_2e Cap Adjustment due to PGV Shutdown			
Generating Station	**CSP Permit No.**	**CO_2e Emission Cap** [a,b,c, d]	
		Metric Tons per Year [b]	**Short Tons per Year**
AES Hawaii, LLC Cogeneration Plant [a]	0087-02-C	1,534,598	1,691,605
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	227,906	251,223
Kalaeloa Partners, L.P. Cogeneration Plant	0214-01-C	993,198	1,094,813
HECO Campbell Industrial Park Generating Station	0548-01-C	48,752	53,740
HECO Honolulu Generating Station	0238-01-C	0	0
HECO Kahe Generating Station	0240-01-C	1,935,707	2,133,752
HECO Waiau Generating Station	0239-01-C	733,265	808,286
HELCO Kanoelehua-Hill Generating Station	0234-01-C	171,991	189,588
HELCO Keahole Generating Station	0007-01-C	248,043	273,421
HELCO Puna Generating Station	0235-01-C	64,666	71,282
HELCO Shipman Generating Station	0236-01-C	0	0
MECO Kahului Generating Station	0232-01-C	140,281	154,633
MECO Maalaea Generating Station	0067-01-C	417,182	459,864
MECO Palaau Generating Station	0031-04-C	23,999	26,454
Combined		6,539,587[d]	7,208,661

[a] AES Hawaii, LLC proposal cap is 10,000 short tons of CO_2e emissions above the baseline of 1,681,605 short tons.
[b] Metric Tons = (0.90718474) x (Short Tons).
[c] Individual caps that were adjusted for facilities on Hawaii Island due to the PGV shutdown are highlighted in red.
[d] Totals may not sum due to independent rounding.

The temporary combined emissions cap for 2019 will be made part of the permit for each partnering facility in accordance with HAR §11-60.1-204(d)(6)(C). Pursuant to HAR §11-60.1-202, a "facility-wide GHG emissions cap" means a permit emissions limitation, applicable to a covered source, limiting the entire source's annual non-biogenic GHG, and biogenic nitrous oxide and methane emissions. In accordance with HAR §11-60.1-202, a facility-wide GHG emissions cap may also be defined in multiple CSPs to identify partnering facilities with an approved combined GHG emissions cap as described in HAR §11-60.1-204(d)(6)(A).

The temporary total combined cap of 7,208,661 short tons for operating year 2019 is a 13.78% reduction from the total combined baseline emissions of 8,361,021 short tons. Although the reduction is less than 16% from the total combined baseline GHG emissions level, there are no provisions in HAR §11-60.1-204(h) that require a GHG control assessment for revising the cap due to reasonably unforeseen events beyond the control of the owner or operator of an affected source.

In response to public comments on draft permits to incorporate GHG cap provisions to limit GHGs, AES Hawaii, LLC negotiated adjustments to its initial individual GHG cap proposal of 1,691,605 short tons. The initial cap proposal by AES Hawaii, LLC was 10,000 short tons above its individual GHG baseline level of 1,681,605 short tons. As indicated in HECO's January 23, 2020 letter regarding the adjustment of site-specific caps, AES Hawaii, LLC agreed to reduce its individual GHG emissions cap by 10,000 short tons for a zero percent reduction from its individual baseline level.

After further negotiations, AES Hawaii, LLC ultimately agreed to a GHG cap adjustment of 16% below its baseline level which is documented in May 22, 2020 and June 9, 2020 emails from HECO. This 16% reduction (269,075 short tons of CO_2e) from the GHG baseline plus 10,000 short tons reduction from the initial GHG cap proposal of 1,691,605 short tons was distributed evenly among four (4) partnering facilities on Oahu that included Kalaeloa Partners, L.P, HECO Campbell Industrial Park Generating Station, HECO Kahe Generating Station, and HECO Waiau Generating Station. Each individual cap for these four (4) facilities was increased by 69,764 short tons of CO_2e emissions for a total combined CO_2e emission increase of 279,056 short tons. Therefore, the total combined partnership GHG emissions cap is unchanged. This adjustment to distribute emissions to Oahu partnering plants excluded HECO Honolulu Generating Station and the AES Hawaii, LLC cogeneration plant.

For 2020 and beyond, individual caps will remain at the levels originally proposed by the partnering facilities, except that for AES, Hawaii, LLC, Kalaeloa Partners, L.P, HECO Campbell Industrial Park Generating Station, HECO Kahe Generating Station, and HECO Waiau Generating Station, individual caps will remain at the level agreed in the partnership for distributing emissions after adjusting the individual GHG emission cap for AES Hawaii, LLC. The individual GHG emissions cap for AES Hawaii, LLC will be a 16% reduction from its individual GHG emission baseline level.

Individual caps for the Hawaii Island facilities will return to the levels proposed prior to the PGV shutdown. The levels are provided in the table on page 7 showing GHG caps proposed on page A-1 of the GHG emission reduction plan before deciding to request an adjustment to the caps due to the shutdown of PGV as a result of volcanic activity.

The CO_2e emission baselines and GHG emission caps proposed for the partnering facilities, that achieve a 16% reduction in GHG emissions from the total combined baseline level, are provided in the following table pursuant to HECO's June 9, 2020 email for calendar year 2020 and beyond:

2020 and Beyond CO_2e Facility Emission Caps and Actual GHG Baseline						
Plant	CSP Permit No.	Emissions (short tons)				% Reduction
		Baseline CO_2e	Baseline Biogenic CO_2	Baseline CO_2e Less Biogenic CO_2	CO_2e Cap (see notes a,b,& c)	
		(a)	(b)	(c)=(a)-(b)	Proposed	
AES	0087-02-C	1,681,605	0	1,681,605	1,412,548	16.0%
Hamakua	0243-01-C	182,975	0	182,975	153,699	16.0%
Kalaeloa	0214-01-C	1,094,813	0	1,094,813	1,164,577	-6.4%
HECO CIP	0548-01-C	19,179	4,233	14,946	123,504	-726.3%
HECO Honolulu[a]	0238-01-C	133,609	0	133,609	0	100%
HECO Kahe	0240-01-C	2,776,073	0	2,776,073	2,203,516	20.6%
HECO Waiau	0239-01-C	1,074,359	0	1,074,359	878,050	18.3%
HELCO Hill	0234-01-C	222,784	0	222,784	172,456	22.6%
HELCO Keahole	0007-01-C	191,387	0	191,387	242,208	-26.6%
HELCO Puna	0235-01-C	99,691	0	99,691	31,747	68.2%
HELCO Shipman	0236-01-C	10,192	0	10,192	0	100% Plant Closed
MECO Kahului	0232-02-C	230,839	0	230,839	154,633	33.0%
MECO Maalaea	0067-01-C	620,654	1,142	619,512	459,864	25.8%
MECO Palaau	0031-04-C	28,236	0	28,236	26,454	6.3%
Combined		8,366,396	5,375	8,361,021[d]	7,023,256[d]	16.0%

[a] HECO Honolulu Generating Station is currently deactivated (not operating but could restart if necessary).

[b] AES Hawaii, LLC individual cap was adjusted to reduce the cap by 10,000 short tons plus 16% reduction (269,057 short tons) below baseline level for a total 279,057 short ton reduction as shown in brown. AES Hawaii, LLC's individual GHG cap was adjusted to reduce the cap by 279,057 short tons.

[c] Adjustment due to AES Hawaii, LLC cap reduction is 69,764 short tons that add up to 279,056 tons for four (4) facilities highlighted in red. Adjustments in the table above were made to individual caps proposed on page A-1 of HECO's greenhouse gas emission reduction plan submitted on July 26, 2019 pursuant to HECO's June 9, 2020 email with documents prepared by the partners. Individual caps were adjusted for facilities in the table above due to the PGV shutdown and the AES Hawaii, LLC individual cap adjustment. The AES Hawaii, LLC cap adjustment is a 10,000 short ton reduction from the previous proposal plus a 16% reduction (269,057 short tons) from the individual baseline level from another proposal. Adjustments were distributed equally among four (4) Oahu facilities excluding AES Hawaii, LLC and the Honolulu Generating Station. The Individual cap adjustment to these facilities was an additional 69,764 short tons of CO_2e emissions for each of the four (4) facilities highlighted in red. Totals may not sum due to independent rounding.

[d] Total combined partnering facility proposed GHG baseline and GHG emission cap are 8,361,022 and 7,023,257 short tons, respectively. Totals may not sum due to independent rounding.

The combined emissions cap for 2020 and beyond will be made part of the permit for each partnering facility in accordance with HAR §11-60.1-204(d)(6)(C). Pursuant to HAR §11-60.1-202, a "facility-wide GHG emissions cap" means a permit emissions limitation, applicable to a covered source, limiting the entire source's annual non-biogenic GHG, and biogenic nitrous oxide and methane emissions. In accordance with HAR §11-60.1-202, a facility-wide GHG emissions cap may also be defined in multiple CSPs to identify partnering facilities with an approved combined GHG emissions cap as described in HAR §11-60.1-204(d)(6)(A).

The total combined GHG emissions cap for 2020 and beyond is a 16% reduction from the total combined baseline emissions level established for the partnering facilities.

For information, the table below titled "Actual GHG Baseline and Notional 16% CO_2e Facility Emission Caps" shows the total combined baseline and GHG emissions cap if a sixteen percent (16%) reduction had been applied to each partnering facility separately. The total combined emissions cap in the table below achieves the same reduction as that proposed for the partnering facilities that have combined their facility-wide emission caps to leverage emission reductions in meeting the combined GHG emission caps in accordance with HAR Subparagraph 11-60.1-204(d)(6)(A). The total combined CO_2e cap in the table below for the notional cap is 7,023,258 short tons per year which is a 16% reduction from the total combined baseline. The total combined CO_2e emission cap proposed, as shown in the table on Page 14 of this review for 2020 and beyond, is 7,023,257 short tons per year which is a 16% reduction from the total combined baseline. Totals may not sum due to independent rounding.

Actual GHG Baseline and Notional 16% CO_2e Facility Emission Caps						
Plant	CSP Permit No.	Emissions (short tons)				% Reduction
		Baseline CO_2e	Baseline Biogenic CO_2	Baseline CO_2e Less Biogenic CO_2	CO_2e Cap	
		(a)	(b)	(c)=(a)-(b)	Notional	
AES	0087-02-C	1,681,605	0	1,681,605	1,412,548	16.0%
Hamakua	0243-01-C	182,975	0	182,975	153,699	16.0%
Kalaeloa	0214-01-C	1,094,813	0	1,094,813	919,643	16.0%
HECO CIP	0548-01-C	19,179	4,233	14,946	12,555	16.0%
HECO Honolulu[a]	0238-01-C	133,609	0	133,609	112,232	16.0%
HECO Kahe	0240-01-C	2,776,073	0	2,776,073	2,331,901	16.0%
HECO Waiau	0239-01-C	1,074,360	0	1,074,360	902,462	16.0%
HELCO Hill	0234-01-C	222,784	0	222,784	187,139	16.0%
HELCO Keahole	0007-01-C	191,387	0	191,387	160,765	16.0%
HELCO Puna	0235-01-C	99,691	0	99,691	83,740	16.0%
HELCO Shipman	0236-01-C	10,192	0	10,192	8,561	16.0%
MECO Kahului	0232-02-C	230,839	0	230,839	193,905	16.0%
MECO Maalaea	0067-01-C	620,654	1,142	619,512	520,390	16.0%
MECO Palaau	0031-04-C	28,236	0	28,236	23,718	16.0%
Combined		8,366,396	5,375	8,361,022	7,023,258	16.0%

[a]The HECO Honolulu Generating Station is currently deactivated (not operating but could restart if necessary).

For information, the CAB requested HECO to address GHG emission reductions as a result of the ongoing pandemic. According to an April 9, 2020 press release from Hawaiian Electric at: https://www.hawaiianelectric.com/hawaiian-electric-sees-drop-in-demand-during-pandemic, there has been a significant reduction in the use of electricity as tourism activities cease, businesses close, and thousands of residents stay home to slow the spread of COVID-19.

In a May 22, 2020 email, Hawaiian Electric anticipates that the resumption of economic activity will increase the use of electricity to levels that could approach pre-COVID-19 conditions; however, it is not clear to HECO when that will occur.

The CAB used a Tier 1 methodology in 40 Code of Federal Regulations (CFR) Part 98, §98.33, to validate the proposed individual and total combined GHG emission caps. Enclosure 1 provides a bar chart of solid fuel and limestone sorbent consumption. Enclosure 2 provides data on liquid fuel consumption. Solid fuel and limestone sorbent consumption are shown in Enclosure 3 for bar chart in Enclosure 1 and for GHG emission curves in Enclosure 6. Liquid fuel consumption data is shown in Enclosure 4 for bar chart in Enclosure 2 and GHG emission curves in Enclosure 6. Total combined emissions for curves in Enclosure 6 are provided in Enclosure 5. Total combined partnering facility emissions from 2005 to 2016 are provided in Enclosure 7. Enclosure 8 provides total combined GHG emission curves for all partnering facilities based on a Tier 1 calculation methodology.

Enclosure 5 shows that baseline GHG emissions proposed for the AES coal-fired cogeneration plant are about 0.259% higher than that estimated by CAB using the Tier 1 methodology. The CAB used default heating values and fuel consumption data to estimate GHGs, whereas AES used a Tier 1 methodology as applicable as well as a Tier 3 methodology with actual carbon content data from fuel sampling coal. Since actual carbon content from burning coal was used, AES's Tier 3 estimates are more representative of actual emissions.

3. Proposed Control Strategy.

   AES is proposing as its control strategy, to partner with the Hawaiian Electric Companies and other IPPs for combining emission caps to leverage the emissions reductions among partnering facilities. In the event there is an energy shortfall from unplanned outages or other issues, AES may be required to generate additional electricity. Therefore, the adjusted individual cap for AES allows for the possible generation equal to that which had been generated in 2010. The total combined partnership cap, however, represents a sixteen percent (16%) reduction in GHG emissions from the total combined partnership baseline emissions by the end of 2021.

<u>Federal Requirements</u>:

40 CFR Part 98, Subpart A, Mandatory Greenhouse Gas Reporting is applicable to this facility because actual CO_2e emissions from stationary fuel combustion units at the coal-fired cogeneration plant are greater than 25,000 metric tons per year.

40 CFR Part 98, Subpart C, General Stationary Fuel Combustion Sources is applicable to this facility because the boilers and limestone dryers are stationary fuel combustion sources as defined in §98.30 and the AES cogeneration plant meets the applicability requirements of 40 CFR §98.2(a)(2).

Pursuant to 40 CFR §98.33, a Tier 4 calculation methodology using data from a continuous emission monitoring system (CEMS) is required for determining CO_2 emissions from the boilers since:

1. The boilers have a maximum rated heat input capacity greater than 250 MMBtu/hr;
2. The units combust solid fossil fuel as the primary fuel;
3. These units have operated for more than 1,000 hours in any calendar year since 2005;
4. The boilers have an installed CEMS;
5. The installed CEMS include a gas monitor; and
6. The gas monitors are required by the operating permit to undergo periodic quality assurance testing in accordance with Appendix F to Part 60 of 40 CFR.

In accordance with 40 CFR §98.33 (b)(5)(ii), AES is required to use a Tier 4 calculation methodology involving a CEMS for the coal-fired boilers no later than January 1, 2011.

The CEMS measures CO_2 emissions from fuel combustion that include coal as the primary fuel, tire derived fuel (TDF), activated carbon, fuel oil No. 2, and specification used oil. Additional CO_2 emissions will result in the boiler exhaust stream due to the reaction between acid gas and sorbent from limestone injection. The total CO_2 from combustion and sorbent is measured by the CEMS.

According to Relative Accuracy Test Audit and Annual Compliance Test Program Report No. 11-2075, each boiler unit is monitored by their own CEMS. As indicated by AES personnel, emissions are added from both CEMS servicing each boiler and compared to the total combined emission limits specified for the boilers in Attachment IIA of the permit.

Calculation of methane (CH_4) and nitrous oxide (N_2O) mass emissions from the boilers and dryers is performed using Equation C-8 in 40 CFR §98.33.

Calculation of CO_2 mass emissions from the two (2) limestone dryers fired on fuel oil No. 2 is performed in accordance with a Tier 1 methodology.

Calculation of CO_2 emissions from sorbent is performed using Equation C-11 in 40 CFR §98.33, except when those CO_2 emissions are monitored by a CEMS.

The following National Emission Standards for Hazardous Air Pollutants (NESHAP) apply:

40 CFR Part 63 - NESHAP
- Subpart A – General Provisions
- Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

The following New Source Performance Standards (NSPS) apply:

40 Code of Federal Regulations (CFR) Part 60 - NSPS
- Subpart A - General Provisions
- Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978
- Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels
- Subpart Y - Standards of Performance for Coal Preparation Plants
- Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants

40 CFR Part 68 - Accidental Release Prevention Requirements was listed as an applicable requirement for the AES's coal-fired cogeneration plant.

Non-Applicable Requirements

State Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 7	Prevention of Significant Deterioration Review
Subchapter 9	Hazardous Air Pollution Sources
HAR 11-60.1-180	National Emission Standards for Hazardous Air Pollutants

Subchapter 11
HAR 11-60.1-204(d)(2) GHG Control Assessment
HAR 11-60.1-204(d)(3) Available Control Measures
HAR 11-60.1-204(d)(4) The Technically Feasible Measures
HAR 11-60.1-204(d)(5) Control Effectiveness and Cost Evaluation

GHG Control Assessment.

AES has proposed a total combined GHG emissions reduction of sixteen percent (16%) from the total combined baseline emissions estimated for partnering facilities by the end of 2021. Pursuant to HAR §11-60.1-202, a facility-wide GHG emissions cap may be defined in multiple covered source permits to identify partnering facilities with an approved combined GHG emissions cap as described in HAR §11-60.1-204(d)(6)(A). As specified in HAR §11-60.1-204(d)(B)(2), if the required GHG emissions cap requiring a sixteen percent (16%) emissions reduction from baseline year is deemed unattainable, the permittee shall conduct a GHG control assessment. Since the facility-wide GHG emissions cap (total combined GHG cap for partnering facilities) is 16% below the total combined baseline GHG emissions level, AES is not required to perform a GHG control assessment for determining whether the required GHG emissions cap is attainable.

A GHG control assessment is also not required for temporary cap adjustments due to events which are beyond the control of the owner or operator of an affected facility.

Although a GHG control assessment is not required, AES addressed GHG emission control options pursuant to HAR §11-60.1-204(d)(3). AES found that the technically feasible options in the table below were not cost effective. The average annual cost effectiveness ranged from $51 per ton for soot blowing to $397 for turbine blade upgrade to $1,792 per ton for air heater temperature reduction. It was concluded that GHG control options having a cost effectiveness of greater than $23 per ton were not cost effective. Co-firing options were also found by AES to increase HAP emissions and change fly ash composition and delivery-related emissions.

GHG Control Option	**GHG Control Effectiveness % Removal**	**Expected GHG Emission Rate**		**Expected**
		Short Tons CO_2e/year	**Pounds CO_2e/kWh (gross)**	
Pelletized Biomass Co-firing @ 25% Heat Input	16%	1,412,549	1.780	269,056
Local Eucalyptus Biomass Co-firing – 150,000 tons per year	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 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

GHG Control Option	GHG Control Effectiveness % Removal	Expected GHG Emission Rate		Expected
		Short Tons CO_2e/year	Pounds CO_2e/kWh (gross)	
VFD Motors	0.30%	1,676,560	2.028	5,045
Baseline Emissions	----	1,681,605	2.034	-----

Federal Requirements:

The following NESAP does not apply to the coal-fired cogeneration plant:

40 CFR Part 63 - NESHAP
Subpart Q – NESHAP for Industrial Process Cooling Towers

The cooling tower is not subject to NESHAP, Subpart Q, because it did not use chromium-based water chemicals at the time this NESHAP was promulgated, nor does AES use this chemical at the present time.

40 CFR Part 61, NESHAP. There are no standards in 40 CFR Part 61 that apply to this facility.

Best Available Control Technology (BACT)

The BACT analyses from the previous permit application review is still valid. A BACT analysis is required for new or modified sources that have the potential to emit or increase emissions above significant amounts as defined in HAR 11-60.1-1. Since this is not a new source, nor are any modifications proposed that have the potential to cause a significant increase in air emissions, a BACT analysis is not required.

Prevention of Significant Deterioration (PSD)

The PSD determination from the previous permit application review is still valid and additional PSD review is not required. This facility is not a new major stationary source, nor does this application propose any major modifications to a major stationary source as defined in 40 CFR Part 52.21. A major modification is defined as a project at an existing major source that will result in a significant and a significant net emissions increase above specified emission thresholds for pollutants subject to regulation.

Major Source/ Synthetic Minor Applicability

The facility's classification as a major source remains unchanged from the previous permit application review.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64

The purpose of CAM is to provide reasonable assurance that compliance is being achieved with large emission units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR, Part 64, for CAM to be applicable, the emissions unit must: (1) be located at a major source; (2) be subject to an emissions limit or standard; (3) use a control device to achieve compliance; (4) have potential pre-control emissions that are greater than the major source level; and (5) not otherwise be exempt from CAM.

The application for permit modification to incorporate the GHG emissions cap provides a CAM plan for monitoring particulate emitted by the boilers that rely on baghouses to meet the particulate emission limits.

CAM requirements will be addressed when processing the permit renewal application.

Air Emissions Reporting Requirements (AERR)

40 CFR Part 51, Subpart A – AERR, is based on emissions of criteria pollutants from point sources (as defined in 40 CFR Part 51, Subpart A), which exceeds AERR thresholds as shown below.

Pollutant [1]	Potential Emissions (TPY)	AERR (Total Facility)			DOH In-House Annual Emissions Reporting (Total Facility)	
		Thresholds (TPY)		Exceeds Threshold	Thresholds (TPY)	Exceeds Threshold
		1 yr Cycle (Type A)	3 yr Cycle (Type B)			
NO_X	1,043	2,500	100	Yes	25	Yes
SO_2	2,846	2,500	100	Yes	25	Yes
CO	1,790	2,500	1,000	Yes	250	Yes
PM_{10}	388	250	100	Yes	25	Yes
$PM_{2.5}$	388	250	100	Yes	----	NA
VOC	141	250	100	Yes	25	Yes
Pb (Actual) [2]	0.0088		0.5	No	5	No
HAPs	61		---	NA	5	Yes

[1] Criteria pollutants include NO_X, sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), ozone (formed from precursor VOCs), and lead (Pb).
[2] Actual lead emissions are from State and Local Emissions Inventory System (SLEIS) for year 2016.

Since the facility-wide emission levels of one or more air pollutant(s) exceeds the reporting threshold(s), the AERR and DOH In-House Annual Emissions Reporting requirements remain unchanged from the previous permit application review and annual emissions reporting for the facility is still required for in-house recordkeeping purposes.

Insignificant Activities

The following storage tanks at the AES cogeneration plant are insignificant activities:

Tank Description	Tank Contents	Capacity (gallons)	Justification
Three (3) Above Ground Storage	-----------	300 each	HAR §11-60.1-82(f)(1)
Fuel Storage Tank	Spec Used Oil	17,631	HAR §11-60.1-82(f)(1)
Pressurized Tank	Ammonia	25,000	HAR §11-60.1-82(f)(1)

The following fuel burning equipment at the AES cogeneration plant are insignificant activities:

Unit Description	Capacity	Justification
Other than Smoke House Generators and Gasoline Fired Industrial Equipment, Fuel Burning Equipment Less than one (1) MMBtu/hr, or Combination of Fuel Burning Equipment Operating as a Single Unit with a Capacity Less Than 1MMBtu/hr.	< 1 MMBtu/hr	HAR §11-60.1-82(f)(2)
Emergency Engine Generator and Emergency Boiler Feed Water Pump.*	Various	HAR §11-60.1-82(f)(5)

*Emergency diesel engine generator used exclusively to provide electricity, standby sewage pump drives, and other emergency equipment used to protect the health and welfare of personnel and the public, all of which are used only during power outages, emergency equipment maintenance and testing, and which:

(1) Are fired exclusively by natural or synthetic gas; or liquefied petroleum gas; or fuel oil No. 1 or No. 2; or diesel fuel oil No. 1D or No. 2D; and
(2) Does not trigger a PSD or covered source review, based on their potential to emit regulated or hazardous air pollutants.

Mobile generators, air compressors, welders, and pressure washer are insignificant per HAR §11-60.1-82(d)(4).

Four (4) limestone feeders, each equipped with a baghouse, are insignificant activities pursuant to HAR §11-60.1-82(f)(7).

One (1) pulverized limestone storage hopper with baghouse is an insignificant pursuant to HAR §11-60.1-82(f)(7).

Fabric filter/baghouses associated with solid fuel conveyance are insignificant activities in accordance with HAR §11-60.1-82(f)(7).

Biomass handling operations are insignificant activities pursuant to HAR §11-60.1-82(f)(7).

Alternate Operating Scenarios

The application for significant modification did not propose any new alternate operating scenarios, however, in April 2, 2020. correspondence, HECO requested the DOH to consider provisions in the permits that allows the emissions cap for partnering facilities to be increased for calendar years 2019 and 2020 in the event the start-up of PGV operations is delayed. In response, the DOH has agreed to amend the permits to incorporate the following alternate operating scenarios:

For the PGV facility shutdown due to volcanic activity on the island of Hawaii in 2018, if the combined generation of the PGV facility and other renewable energy sources on Hawaii Island are not restored to levels that PGV had preceding its shutdown, the following alternate individual and total combined GHG emissions caps will be calculated as follows:

a. One-twelfth (1/12) of the 2019 individual GHG emission cap adjustments for Hawaii Island partnering facilities will be added to the individual GHG emission caps of these facilities set forth for 2020 and beyond for each month the renewable energy levels are not restored to PGV system levels preceding its shutdown.
b. One-twelfth (1/12) of the total combined cap adjustment for 2019 of 185,404 short tons will be added to the total combined GHG emission cap specified for 2020 and beyond for each month renewable energy levels are not restored to PGV system levels preceding its shutdown.

Project Emissions

Potential emissions of particulate matter (PM), SO_2, NO_X, CO, VOCs and hazardous air pollutants (HAPs) were estimated for coal combustion in Boilers A and B. The pound per hour emission limits listed in the table below were used to determine maximum potential emissions based on 8,760 hours per year operation. The following table provides maximum permitted emission rates for the one stack servicing both boilers:

Compound	Maximum Emission Limits [1]			
	lb/hr	lb/mmBtu	ppmvd @ 15% O_2	gr/dscf @ 12% CO_2, dry
SO_2	645.0	1.2	48	--
NO_X baseload [2]	236.5	0.5	25	--
NO_X low load [2,3]	236.5	0.5	59	--
CO	408.4	--	70	--
VOC [4]	32.2	--	3.5	--
Lead (Pb)	5.7	--	--	1.2E-3
PM/PM_{10} [5]	32.2	0.03	--	7.0E-3
Fluorides	0.20	9.3E-5	--	--
Mercury	0.17 0.0026	8.1E-5 (prior to 4/16/2015) 1.2E-6 (on and after 4/16/2015)	--	--
Beryllium	0.067	3.1E-5	--	--
Sulfuric Acid Mist	4.10	1.9E-3	--	--
Hydrogen Chloride (HCl)	4.30	0.002		

Notes:
[1] 3-hour average with standard conditions assumed to be 68^0F and 29.92 inches Hg. Stack concentrations assumed to be 5% H_2O, 6.5% O_2 and 12% CO_2. Stack temperature and pressure at outlet is 265^0F and 29.92 inches Hg respectively.
[2] Molecular weight of NO_x taken to be that of NO_2 (46).
[3] Low load is an individual boiler heat input of less than 450 mmBtu/hr.
[4] Molecular weight of VOC taken to be that of propane (44).
[5] PM_{10} emission rate assumed to be 100% of the total particulate matter emission rate.

Other potential emissions for fuel oil combustion in the boilers and limestone dryers, coal and limestone processing, ash handling, and the cooling tower were based on AP-42 emission factors. The coal and ash emissions include metal HAPs that are part of the coal and ash dust. All emissions account for the use of air pollution controls. The calculations were based on those in permit application Nos. 0087-09 and 0087-10.

The GHG emissions cap will not increase emissions of criteria pollutants and HAPs. The table below provides facility-wide maximum potential annual emissions based on operating 8,760 hr/yr with air pollution controls and permit emission limits. Emissions from the dryers were based on the maximum 34 gallon per hour fuel combustion for each dryer, 8,760 hours per year operation, and AP-42 emission factors. The CAB updated mercury emissions in this table based on the emission limit that applies on and after 4/16/2015, for the CFB boilers.

Pollutant	Steam Boilers [1] (TPY)	Coal Processing (TPY)	Limestone Processing (TPY)	Ash Handling (TPY)	Cooling Tower (TPY)	Storage Tanks (TPY)	Total (TPY)
SO_x	2,825		21.15				2,846
NO_x	1,036		7.14				1,043
PM	141	5.37	1.81	2.66	237		388
CO	1,789		1.49				1,790
VOC	141		0.07			1.84 E-02	141
Fluorides	0.876						0.876
Lead	25	1.07E-05	9.99E-05	1.88E-04			25
Mercury	1.13E-02 [2]	1.61E-07	1.34E-06	2.70E-05			1.15E-02
Beryllium	0.293	5.37E-07	1.43E-06	4.85E-05			0.293
Sulfuric Acid Mist	18						18
Hydrogen Chloride (HCL)	18.83		0.388				19.22
Antimony	8.48E-03	4.30E-07	6.13E-07	2.7E-05			8.51E-03
Arsenic	0.193	1.50 E-05	1.43 E-04	2.85 E-04			0.193
Cadmium	2.40 E-02	1.07 E-07	1.18 E-05	2.85 E-04			2.40E-02
Chromium	0.122	3.22 E-05	3.58 E-05	6.60 E-04			0.123
Cobalt	4.71E-02	1.56E-05	3.79E-06				4.71E-02
Manganese	0.231	3.76 E-05	1.90 E-04				0.231
Nickel	0.132	4.30 E-05	2.64 E-05	1.97 E-03			0.134
Selenium	0.612	1.61 E-06	6.96 E-06	1.66 E-04			0.612
2,4-Dinitrophenol	1.70E-04						1.70E-04
2-Chloroacetophenone	3.30E-03						3.30E-03
4-Nitrophenol	1.04E-04						1.04E-04
Acetaldehyde	0.782						0.782
Acetophenone	7.06E-03						7.06E-03
Acrolein	3.77						7.06E-03
Benzene	3.96		3.18 E-05				3.96
Benzyl chloride	0.330						0.330
Bis(2-Ethylhexyl)phthalate	3.44E-02						3.44E-02
Bromoform	1.84E-02						1.84E-02
Carbon disulfide	6.12E-02						6.12E-02
Carbon tetrachloride	4.24E-02						4.24E-02
Chlorobenzene	3.11E-02						3.11E-02
Chloroform	2.64E-02						2.64E-02
Cumene	2.50E-03						2.50E-03
Chlorobenzene	3.11E-02						3.11E-02
Chloroform	2.64E-02						2.64E-02
Cumene	2.50E-03						2.50E-03
Cyanide	1.18						1.18
Dimethyl sulfate	2.26E-02						2.26E-02
Ethyl benzene	2.92 E-02		9.45 E-06				2.92E-02
Ethyl chloride	1.98E-02						1.98E-02
Ethyl dibromide	5.65E-04						5.65E-04
Formaldehyde	4.14						4.14
Hexane	3.15E-02						3.15E-02
Hexane	3.15E-02						3.15E-02
Isophorone	0.273						0.273
Methyl bromide	7.53E-02						7.53E-02
Methyl chloride	0.250						0.250

Pollutant	Steam Boilers [1] (TPY)	Coal Processing (TPY)	Limestone Processing (TPY)	Ash Handling (TPY)	Cooling Tower (TPY)	Storage Tanks (TPY)	Total (TPY)
Methyl Ethyl Ketone	0.184						0.184
Methyl hydrazine	8.00E-02						8.00E-02
Methyl methacrylate	9.42E-03						9.42E-03
Methyl tert butyl ether	1.65E-02						1.65E-02
Methylene chloride	0.137						0.137
Pentachlorophenol	4.80E-05						4.80E-05
Phenol	4.80E-02						4.80E-02
Phosphorus	2.54E-02						2.54E-02
Propionaldehyde	5.74E-02						5.74E-02
Styrene	1.79						1.79
Tetrachloroethene	3.58E-02						3.58E-02
Tetrachloroethylene	2.02E-02						2.02E-02
Toluene	0.866						0.866
Trichloroethene	2.83E-02						2.83E-02
Vinyl acetate	3.58E-03						3.58E-03
Xylenes	2.35 E-02		3.24E-05				2.35E-02
HAPs: (Polycyclic Organic Matter Including Polycyclic Aromatic Hydrocarbons)							
5-Methyl chrysene	1.04E-05						1.04E-05
Acenaphthene	8.57E-04		6.28E-06				8.63E-04
Acenaphthylene	4.71E-03		7.52E-06				4.72E-03
Anthracene	2.83E-03		3.62E-07				2.83E-03
Benz(a)anthracene			5.96E-07				5.96E-07
Benzo(a)anthracene	6.12E-05						6.12E-05
Benzo(a)pyrene	2.45E-03						2.45E-03
Benzo(b,j,k)fluoranthene	2.79E-04		4.40E-07				2.79E-04
Benzo(g,h,i)perylene	8.76E-05		6.72E-07				8.83E-05
Biphenyl	8.00E-04						8.00E-04
Chrysene	3.58E-05		7.08E-07				3.65E-05
Dibenzo(a,h)anthracene	8.57E-06		2.48E-07				8.82E-06
Fluoranthene	1.51E-03		1.44E-06				1.51E-03
Indeno(1,2,3,c,d)pyrene	8.19E-05		3.18E-07				8.22E-05
Naphthalene	9.13E-02		1.68E-04				9.15E-02
HAPs: (Other Polycyclic Organic Matter – Polychlorinated Biphenyls)							
Decachlorobiphenyl	2.54E-07						2.54E-07
Dichlorobiphenyl	6.97E-07						6.97E-07
Heptachlorobiphenyl	6.22E-08						6.22E-08
Hexachlorobiphenyl	5.18E-07						5.18E-07
Monochlorobiphenyl	2.07E-07						2.07E-07
Pentachlorobiphenyl	1.13E-06						1.13E-06
Tetrachlorobiphenyl	2.35E-06						2.35E-06
Trichlorobiphenyl	2.45E-06						2.45E-06
HAPs: (Dioxin & Furans)	3.06E-06		3.01E-09				3.07E-06
						Total HAPs→	61

[1] Potential to emit from burning coal TDF, spent activated carbon, and wood.
[2] Based on mercury emissions limit after 4/16/2015, a maximum hourly capacity of 2,150 MMBtu/hr for firing 100% coal as follows:

(2,150 MMBtu/hr) x (1.2E-06 lb/MMbtu) x (8,760 hr/yr) x (ton/2,000 lb) = 1.13E-2 tons per year

Maximum potential CO_2e emission estimates, determined in Enclosure 9, are provided in the following table:

MAXIMUM POTENTIAL CO_2e EMISSIONS FOR CIP GENERATING STATION

Description →	ΣGHG Mass-Based Emissions	GWP	CO_2e Emissions Rate	
Source Reference or Derivation →	Enclosure 9	40 CFR §98 Table A-1	(a)*(b)	[(a)*(b)]/1.10231
Unit of Measure →	(tons/year)	None	(tons/year)	(Metric tons/year)
GHG Pollutant ↓	(a)	(b)	(c)	(d)
Carbon Dioxide (CO_2)	2,174,660	1	2,174,660	1,972,818
Methane (CH_4)	228.6	25	5,715	5,185
Nitrous Oxide (N_2O)	33.26	298	9,911	8,991
Maximum Potential CO_2e Emissions			2,190,286	1,986,994

AES is proposing an individual CO_2e emissions cap of 1,681,605 short tons (1,534,598 metric tons) per calendar year for its coal fired cogeneration plant. This individual cap is zero percent increase from the facility's baseline CO_2e emissions level of 1,681,605 short tons (1,534,598 metric tons). While this individual limit may be exceeded, the proposed total combined GHG emissions limit is expected to reduce overall GHG emissions among partnering facilities by sixteen percent (16%) from the total combined baseline emissions level by the end of 2021.

Ambient Air Quality Assessment

An ambient air quality impact assessment was not performed since there are no increases in emissions for the modification to incorporate GHG emission caps.

Significant Permit Conditions

1. The following individual CO_2e caps will be specified in Attachment II – GHG, Special Condition No. C.1.a of CSP No. 0087-02-C for AES Cogenerating Plant:

    a. AES Cogenerating Plant shall not emit or cause to be emitted CO_2e emissions in excess of 1,281,442 metric tons (1,412,548 short tons) per calendar year, except as specified for calendar year 2019 and Attachment II – GHG, Special Condition Nos. C.1.c.iv and C.3 of the permit.
    b. For calendar year 2019, AES Cogenerating Plant shall not emit or cause to be emitted CO_2e emissions in excess of 1,534,598 metric tons (1,691,605 short tons) per calendar year, except as specified in Attachment II – GHG, Special Condition No. C.1.c.iv of the permit.

    Reason: HAR §11-60.1-204(d)(6)(A), §11-60.1-204(h)(4), and §11-60.1-204(h)(5).

2. The following total combined CO_2e emissions caps will be specified in Attachment II – GHG Special Condition No. C.1.b of CSP No. 0087-02-C for AES Cogenerating Plant:

    a. For 2019, all partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of 7,208,661 short tons (6,539,587 metric tons) per calendar year.

b. For 2020 and beyond, all partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of 7,023,257 short tons (6,371,392 metric tons) per calendar year, except as specified in the alternate operating scenario provisions.

Reason: HAR §11-60.1-204(d)(6)(A), §11-60.1-204(h)(4), and §11-60.1-204(h)(5).

3. For purposes of the CO_2e emission limits in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b:

a. The CO_2e emissions shall have the same meaning as that specified in HAR §11-60.1-1;
b. In accordance with HAR §11-60.1-204(d)(6)(B), biogenic carbon dioxide (CO_2) emissions are not included when determining compliance with the emissions limit;
c. The permittee shall be in compliance with the applicable emission limits by the end of 2019, and each calendar year thereafter;
d. The permittee may exceed the emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a, if the GHG emissions limit specified in Attachment II – GHG, Special Condition No. C.1.b., is met; and
e. At no time shall the permittee exceed Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b, simultaneously over a calendar year. For incidences when Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b of this permit, are exceeded simultaneously, emissions in excess of the total combined cap shall be allocated according to the following equation for compliance purposes:

$$X = XG\ \frac{(A - C)}{\sum_{A_i > C_i}(A_i - C_i)}$$

Where:
X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II – GHG, Special Condition Nos. C1.a and C.1.b, respectively.
XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap.
A = Actual GHG emissions from the affected facility.
C = GHG emissions cap for the affected facility.
$\sum_{Ai > ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

Reason: Required by HAR §11-60.1-3, §11-60.1-90, §11-60.1-204.

4. The alternate operating scenario for the PGV facility shutdown due to volcanic activity on the island of Hawaii in 2018, shall remain in effect until an additional net energy generation of 26,883 MWh per month from the PGV facility is reached in any month of the year. The following shall apply to the individual and total combined alternate operating scenario GHG emission cap adjustments starting January 1, 2020 and for any subsequent year until these alternate operating scenarios no longer apply:

a. Attachment II – GHG, Special Condition No. C.3 no longer applies when,

$$NG_{PGV\text{-}R} \geq NG_{PGV2017}$$

Where,

$NG_{PGV2017}$ = 26,883 Net Generating capacity from the PGV facility in calendar year 2017 on an average monthly basis (MWh) preceding its shutdown.
NG_{PGV-R} = Net Generation from the restored PGV facility (MWh per month)

b. The alternate scenario individual GHG emission cap adjustment for calendar year 2019 is 97,524 short tons for Hamakua Energy, LLC, 17,132 short tons for Kanoelehua-Hill Generating Station, 31,213 short tons for Keahole Generating Station, and 39,535 short tons for Puna Generating Station. Starting on January 1, 2020, and for any subsequent year, the alternate scenario GHG emissions individual cap adjustment for each of the foregoing island of Hawaii partnering facilities shall be calculated by adding one twelfth (1/12) of the 2019 annual adjustment for each facility's individual GHG emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a.ii per month for the facilities from January 1 of that year. Monthly adjustments to the individual GHG emission caps shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

c. The PGV alternate scenario total combined cap adjustment for calendar year 2019 is 185,404 short tons. Starting on January 1, 2020, and for any subsequent year, the PGV alternate operating scenario total combined GHG emissions cap adjustment shall be calculated by adding one twelfth (1/12) of the 2019 annual adjustment of 15,450 short tons to the total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b.ii per month from January 1 of that year. Monthly adjustments to the total combined GHG emissions cap shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

d. Monthly adjustments to the individual and total combined GHG emission caps shall be determined with the following equation:

$$AC = FAC/12$$

Where,

FAC = Full Adjustment to CO_2e caps (short tons – refer to table below)
AC = Monthly adjustment to GHG emissions caps

Generating Station	Full Adjustment to CO_2e Caps (Short Tons)	2020 CO_2e Cap (Short Tons)	FAC/12 (Short Tons) [b]
Hamakua Energy	97,524	153,699	8,127
Kanoelehua-Hill	17,132	172,456	1,428
Keahole	31,213	242,208	2,601
Puna	39,535	31,747	3,295
Combined	185,404	see note [a]	15,450

a. Total combined CO_2e cap for all partnering facilities is 7,023,257 short tons.
b. Monthly full CO_2e cap adjustment.

e. Individual GHG emission cap adjustments, affecting the total combined GHG emissions cap, shall only apply to partnering facilities on the island of Hawaii.
f. The permittee may exceed the adjusted individual GHG emissions cap as determined in Attachment II – GHG, Special Condition No. C.3.b, if the adjusted total combined GHG emission cap as determined in Attachment II – GHG, Special Condition No. C.3.c is met.
g. Alternate operating scenario records shall be maintained in accordance with Attachment II - GHG, Special Condition No. D.3.
h. The terms and conditions under each operating scenario shall meet all applicable requirements, including the special conditions of this permit.

Reason: HAR §11-60.1-3, §11-60.1-5, and §11-60.1-204(h)

5. Semi-annual monitoring report submittals for the GHG emission caps and allocating excess emissions pursuant to Attachment II – GHG, Special Condition No. C.1.c.v are as follows:

   a. The permittee shall complete and submit **semi-annual** monitoring reports to the Department. All reports shall be submitted **within sixty (60) days after** the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31), be signed and dated by a responsible official, except that biogenic CO_2 emissions shall be excluded from the total CO_2e emissions.
   b. For calendar year 2019, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2019 calendar year shall be used for reporting and shall be signed and dated by a responsible official.
   c. For calendar year 2020, the permittee shall report the CO_2e emissions **within sixty (60) days** after issuance of this permit or **within sixty (60) days** after the end of the semi-annual calendar period, whichever is later. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2020 calendar year shall be used for reporting and shall be signed and dated by a responsible official.

Reason: HAR §11-60.1-3, §11-60.1-5, and §11-60.1-90.

Conclusion and Recommendation

AES applied for significant permit modification to incorporate the proposed GHG emissions caps and significant permit conditions. These permit additions are required for implementing GHG reduction measures in the GHG emissions reduction plan for the 203 MW coal-fired cogeneration plant pursuant to HAR §11-60.1-204.

The HECO, HELCO, MECO, and IPP plants are proposing a sixteen percent (16%) GHG emissions reduction from the total combined baseline GHG emissions for calendar year 2020 and beyond; and to use a total combined GHG emission cap by partnering pursuant to HAR §11-60.1-204(d)(6)(A).

AES's GHG emissions reduction plan for the 203 MW cogeneration plant was reviewed and determined to be in compliance with HAR §11-60.1-204. The proposed baseline emission rate and emission caps were evaluated using past fuel consumption data and determined to be reasonably representative as documented in Enclosures 1 through 6. Further review in Enclosure 8 shows total combined GHG emissions from partnering facilities following calendar year 2005 have steadily declined slightly more than sixteen percent (16%) below a 2010 baseline emissions level as of the end of calendar year 2016 based on a Tier 1 calculation methodology. Preliminary GHG emissions estimated for the partnership for calendar year 2019, however, are 7,103,530 tons per year which is less than a 16% reduction from the 2010 GHG emissions level in Enclosure 4.

For calendar year 2019 and 2020, the overall partnership caps are adjusted in accordance with HAR §11-60.1-204(h) due to unforeseen events. The shutdown of the PGV geothermal plant for towards the end of 2018 due to volcanic activity and delay in renewable energy projects until 2021 are beyond the control of the partnering facilities.

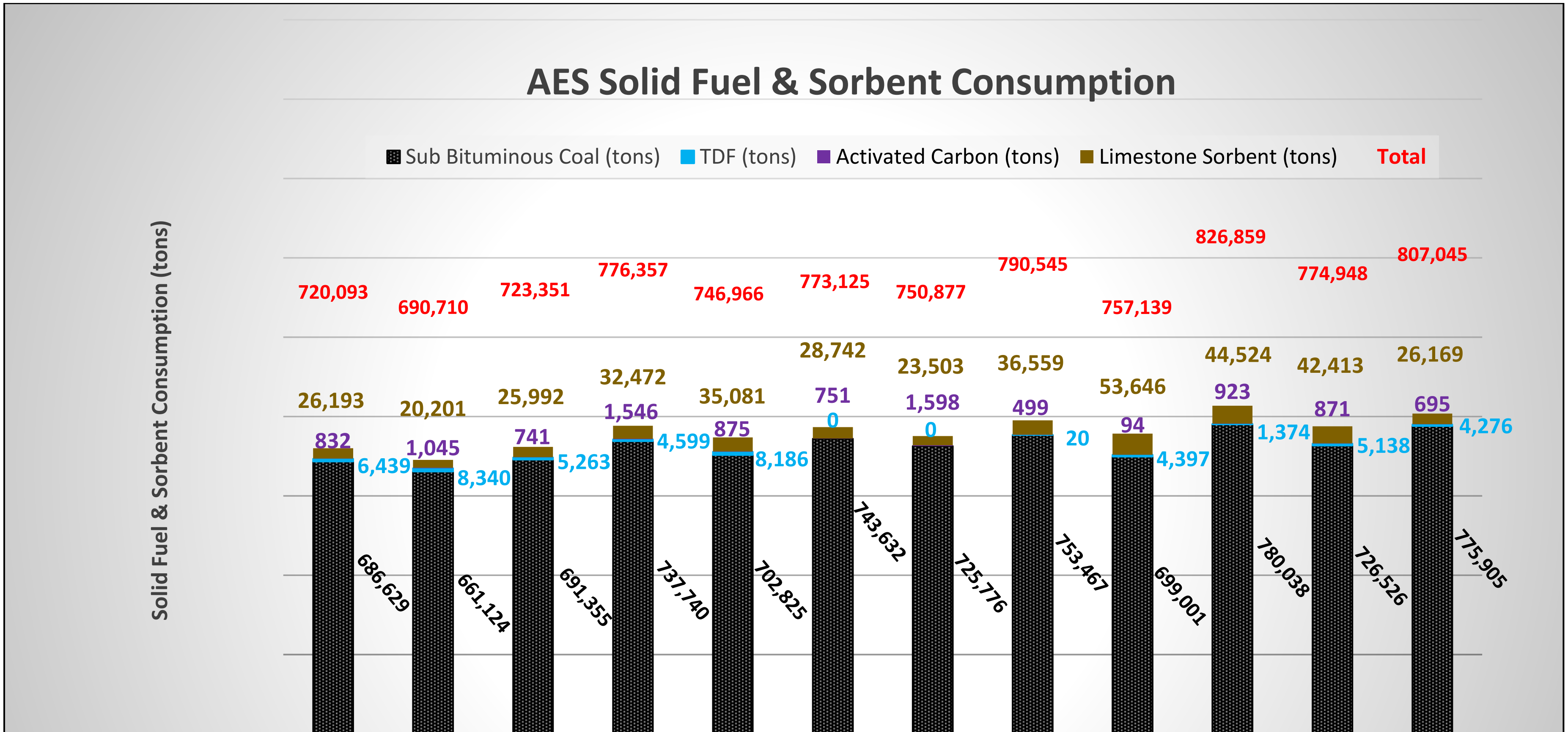
For calendar year 2019 the overall partnership caps are adjusted in accordance with HAR §11-60.1-204(h) due to unforeseen events. The shutdown of the PGV geothermal plant towards the end of 2018 due to volcanic activity and delay in renewable energy projects until 2021 are beyond the control of the partnering facilities. An alternate operating scenario was incorporated into the permit for determining compliance with the facility-wide GHG emissions cap if there is a delay in restoring operation of the PGV facility.

As specified in HAR §11-60.1-204(g), once a facility-wide GHG emission cap is established and incorporated into the covered source permit, the GHG emission reduction plan shall become part of the permit application process for renewals and any required modifications.

Recommend issuance of the significant modification to the covered source permit subject to thirty-day (30-day) public review and comment period in accordance with HAR §11-60.1-205, forty-five day (45-day) Environmental Protection Agency review period, and incorporation of the significant permit conditions.

Review By: Michael "Mike" Madsen
July 10, 2020

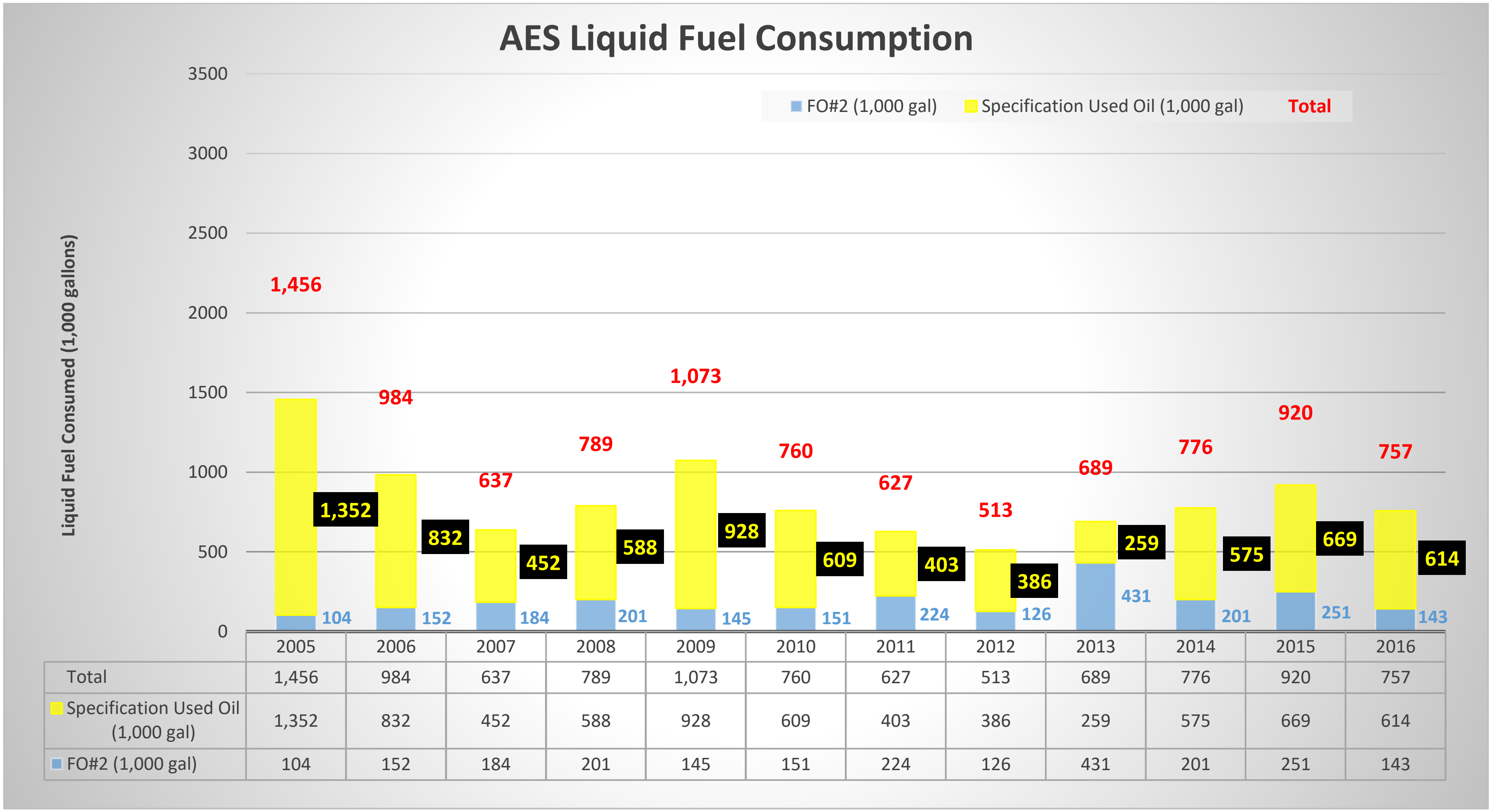
ENCLOSURE 1



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total	720,093	690,710	723,351	776,357	746,966	773,125	750,877	790,545	757,139	826,859	774,948	807,045
Limestone Sorbent (tons)	26,193	20,201	25,992	32,472	35,081	28,742	23,503	36,559	53,646	44,524	42,413	26,169
Activated Carbon (tons)	832	1,045	741	1,546	875	751	1,598	499	94	923	871	695
TDF (tons)	6,439	8,340	5,263	4,599	8,186	0	0	20	4,397	1,374	5,138	4,276
Sub Bituminous Coal (tons)	686,629	661,124	691,355	737,740	702,825	743,632	725,776	753,467	699,001	780,038	726,526	775,905

Enclosure 1 Bar chart showing the total combined solid fuel consumption in short tons for Boilers A and B and the total combined short tons of limestone injected into the combustion zone of the boilers from years 2005 to 2016.

ENCLOSURE 2



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total	1,456	984	637	789	1,073	760	627	513	689	776	920	757
Specification Used Oil (1,000 gal)	1,352	832	452	588	928	609	403	386	259	575	669	614
FO#2 (1,000 gal)	104	152	184	201	145	151	224	126	431	201	251	143

Enclosure 2 Bar chart of the total combined liquid fuel consumption at the AES cogeneration plant from years 2005 to 2016. Fuel consumption includes liquid fuel for Boilers A and B and two (2) limestone dryers. The facility uses fuel oil for boiler startup. Oil-fired dryers are also used to reduce limestone moisture content prior to injecting limestone into the boiler combustion zone for removing SO_2 and acid gases.

ENCLOSURE 3

Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AES														
SOLID FUEL-LIME SORBENT CONSUMPTION DATA														
(a)	See Data Source	Sub Bituminous Coal (tons)	686,629	661,124	691,355	737,740	702,825	743,632	725,776	753,467	699,001	780,038	726,526	775,905
(b)	See Data Source	TDF (tons)	6,439	8,340	5,263	4,599	8,186	0	0	20	4,397	1,374	5,138	4,276
(c)	See Data Source	Activated Carbon (tons)	832	1,045	741	1,546	875	751	1,598	499	94	923	871	695
(d)	See Data Source	Limestone Sorbent (tons)	26,193	20,201	25,992	32,472	35,081	28,742	23,503	36,559	53,646	44,524	42,413	26,169
	(a) + (b) + (c) + (d)	**Total**	**720,093**	**690,710**	**723,351**	**776,357**	**746,966**	**773,125**	**750,877**	**790,545**	**757,139**	**826,859**	**774,948**	**807,045**
	DATA SOURCE→		Emission Inventory Fuel Consumption Data						SLEIS					
PARAMETERS FOR DETERMINING CO_2e EMISSIONS														
(e)	40CFRP98 Table C-1 [Emission Factors]	Heating Value Sub Bituminous Coal (MMBtu/ton)[a]	21.39	21.39	21.39	21.39	21.39	21.39	19.73	19.73	19.73	21.39	21.39	21.39
(f)		Heating Value TDF (MMBtu/ton)	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
(g)		Heating Value Activated Carbon (MMBtu/ton)[b]	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
(h)		CO_2 EF Sub Bituminous Coal (kg/MMBtu)	94.27	94.27	94.27	94.27	94.27	94.27	95.52	95.52	95.52	94.27	94.27	94.27
(i)		CO_2 EF TDF (kg/MMBtu)	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97
(j)		CO_2 EF Activated Carbon (kg/MMBtu)	102.41	102.41	102.41	102.41	102.41	102.41	102.41	102.41	102.41	102.41	102.41	102.41
(k)	Equation C-11 from 40 CFR §98.33	CO_2 Limestone (metric tons)	10,488	8,088	10,407	13,002	14,046	11,508	9,411	14,638	21,480	17,827	16,982	10,478
(l)		CO_2 Limestone (kg)	10.49	8.09	10.41	13.00	14.05	11.51	9.41	14.64	21.48	17.83	16.98	10.48
(m)	40CFRP98 Table C-2 [Emission Factors]	CH_4 EF Sub Bituminous Coal (kg/MMBtu)	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011
(n)		CH_4 EF TDF (kg/MMBtu)	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032
0		CH_4 EF Activated Carbon (kg/MMBtu)	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032
(p)		N_2O EF Sub Bituminous Coal (kg/MMBtu)	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
(q)		N_2O EF TDF (kg/MMBtu)	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042
(r)		N_2O EF Activated Carbon (kg/MMBtu)	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042
(s)	40CFRP98 Table A-1 [Global Warming Potential]	GWP CO_2	1	1	1	1	1	1	1	1	1	1	1	1
(t)		GWP CH_4	25	25	25	25	25	25	25	25	25	25	25	25
(u)		GWP N_2O	298	298	298	298	298	298	298	298	298	298	298	298
CALCULATE FUEL CONSUMPTION IN MMBTU														
(v)	(a)*(e)	Sub Bituminous Coal (MMBtu)	14,686,990	14,141,452	14,788,091	15,780,258	15,033,419	15,906,294	14,319,560	14,865,904	13,791,296	16,685,022	15,540,382	16,596,615
(w)	(b)*(f)	TDF (MMBtu)	180,289	233,518	147,364	128,769	229,200	0	0	560	123,123	38,463	143,853	119,740
(x)	(c)*(g)	Activated Carbon (MMBtu)	24,960	31,350	22,230	46,380	26,250	22,530	47,941	14,974	2,834	27,684	26,130	20,850
(y)	(v)+(w)+(x)	Total (MMBtu)	14,892,239	14,406,320	14,957,685	15,955,407	15,288,869	15,928,824	14,367,501	14,881,438	13,917,253	16,751,170	15,710,365	16,737,205
CALCULATE MASS EMISSIONS														
(z)	[(h)*(v) + (i)*(w) + (j)*(x) + (l)]	CO_2 Mass Emissions (kg)	1,402,598,177	1,356,400,822	1,409,018,841	1,503,425,015	1,439,593,050	1,501,793,648	1,372,714,023	1,421,572,746	1,328,219,707	1,579,038,870	1,480,034,872	1,576,992,223
(aa)	[(m)*(v) + (n)*(w) + (o)*(x)]	CH_4 Mass Emissions (kg)	168,125	164,032	168,096	179,188	173,542	175,690	159,049	164,022	155,735	185,652	176,384	187,062
(bb)	[(p)*(v) + (q)*(w) + (r)*(x)]	N_2O Mass Emissions (kg)	24,361	23,739	24,373	25,984	25,126	25,545	23,113	23,851	22,595	26,974	25,579	27,145
CALCULATE CO_2e EMISSIONS AND COMPARE WITH BASELINE IN GHG REDUCTION PLAN														
(cc)	(z)*(s) + (aa)*(t) + (bb)*(u)	CO_2e Emissions (kg)	1,414,060,945	1,367,575,770	1,420,484,467	1,515,647,949	1,451,419,257	1,513,798,222	1,383,577,824	1,432,780,801	1,338,846,416	1,591,718,377	1,492,066,868	1,589,757,993
(dd)	$(cc)/10^3$	CO_2e Emissions (metric-tons)	1,414,061	1,367,576	1,420,484	1,515,648	1,451,419	1,513,798	1,383,578	1,432,781	1,338,846	1,591,718	1,492,067	1,589,758
(gg)	(gg)*1.10231	**CO_2e Emissions (tpy)**	**1,558,734**	**1,507,492**	**1,565,814**	**1,670,714**	**1,599,914**	**1,668,675**	**1,525,132**	**1,579,369**	**1,475,824**	**1,754,567**	**1,644,720**	
CALCULATE CO_2e CAP AND COMPARE WITH INDIVIDUAL CAP IN GHG REDUCTION PLAN														
(hh)	0.237*(w)*(i)*(1/1,000)	Biogenic CO_2e Emissions (metric-tons)[d]	3,673.373	4,757.913	3,002.525	2,623.658	4,669.931	0.000	0.000	11.410	2,508.623	783.686	2,930.985	2,439.684
(ii)	(kk)*1.10231	Biogenic CO_2e Emissions (tons)	4,049	5,245	3,310	2,892	5,148	0	0	13	2,765	864	3,231	

a: Heating value of 21.39 MMBtu/ton was from 40 CFR Part 98 Table C-1 to Subpart C for mixed coal (Commercial Sector). Heating value of 19.73 MMBtu/ton was from 40 CFR Part 98 Table C-1 to Subpart C for mixed coal (Electric Power Sector).

b: Heating value of 30.00 MMBtu/ton was from 40 CFR Part 98 Table C-1 to Subpart C for Petroleum Coke.

c: Based on E.q. C-11 from 40 CFR Part 98 in §98.33(d)(1) to get metric tons of CO_2 emitted from sorbent. Metric tons of CO_2 was converted to kg of CO_2.

d: Based on information from https://www.betalabservices.com/renewable-carbon/tire-derived-fuels.html that biomass fraction of scrap tires are 18.3% on average for used passenger car tires and 29.1% on average for used truck tires. The average of the two percent averages is 23.7%. The percentages of biomass in the tire dirived fuel (TDF) was based on ASTM D6866 test methods to measure biogenic carbon fraction of TDF.

1 metric-ton=1.10231 tons
1 metric-ton=1000 Kg

Enclosure 3 Solid fuel and limestone sorbent consumption data for bar chart in Enclosure 1 and spreadsheet calculations of GHG emissions for the AES plant between years 2005 and 2016 for GHG emission curves shown in Enclosure 6.

ENCLOSURE 4

AES														
LIQUID FUEL CONSUMPTION DATA														
Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(a)	See Data Source	FO#2 (1,000 gal)	104	152	184	201	145	151	224	126	431	201	251	143
(b)	See Data Source	Specification Used Oil (1,000 gal)	1,352	832	452	588	928	609	403	386	259	575	669	614
	(a) + (b)	Total	1,456	984	637	789	1,073	760	627	513	689	776	920	757
	DATA SOURCE→		Emission Inventory Fuel Consumption Data						SLEIS					
PARAMETERS FOR DETERMINING CO_2e EMISSIONS														
(c)		Heating Value FO#2 (MMBtu/gal)	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138
(d)		Heating Value Specification Used Oil (MMBtu/gal)	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138
(e)		CO_2 EF FO#2 (kg/MMBtu)	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96
(f)		CO_2 EF Specification Used Oil (kg/MMBtu)	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00
(g)		CH_4 EF FO#2 (kg/MMBtu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
(h)		CH_4 EF Specification Use Oil (kg/MMBtu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
(i)		N_2O EF FO#2 (kg/MMBtu)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
(j)		N_2O EF Specification Used Oil (kg/MMBtu)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
(k)	40CFRP98 Table A-1 [Global Warming Potential]	GWP CO_2	1	1	1	1	1	1	1	1	1	1	1	1
(l)		GWP CH_4	25	25	25	25	25	25	25	25	25	25	25	25
(m)		GWP N_2O	298	298	298	298	298	298	298	298	298	298	298	298
CALCULATE FUEL CONSUMPTION IN MMBTU														
(n)	(a)*(c)*10^3	FO#2 (MMBtu)	14,370	20,966	25,453	27,755	20,034	20,795	30,857	17,443	59,437	27,798	34,597	19,762
(o)	(b)*(d)*10^3	Specification Used Oil (MMBtu)	186,535	114,808	62,413	81,085	128,046	84,054	55,628	53,309	35,706	79,342	92,313	84,725
(p)	(n)+(o)	Total (MMBtu)	200,904	135,774	87,866	108,840	148,080	104,850	86,485	70,753	95,144	107,140	126,909	104,487
CALCULATE MASS EMISSIONS														
(q)	[(n)*(e) + (o)*(f)]	CO_2 Mass Emissions (kg)	14,866,331	10,046,452	6,501,044	8,053,043	10,957,083	7,758,042	6,398,626	5,234,995	7,038,245	7,927,249	9,389,901	7,731,225
(r)	[(n)*(g) + (o)*(h)]	CH_4 Mass Emissions (kg)	603	407	264	327	444	315	259	212	285	321	381	313
(s)	[(n)*(i) + (o)*(j)]	N_2O Mass Emissions (kg)	121	81	53	65	89	63	52	42	57	64	76	63
CALCULATE CO_2e EMISSIONS														
(t)	(q)*(k) + (r)*(l) + (s)*(m)	CO_2e Emissions (kg)	14,917,320.01	10,080,911.51	6,523,344.29	8,080,666.73	10,994,665.71	7,784,652.39	6,420,575.92	5,252,951.68	7,062,392.49	7,954,441.10	9,422,110.69	7,757,744.06
(u)	(t)/10^3	CO_2e Emissions (metric-tons)	14,917	10,081	6,523	8,081	10,995	7,785	6,421	5,253	7,062	7,954	9,422	7,758
(v)	u*1.10231	CO_2e Emissions (tons)	16,444	11,112	7,191	8,907	12,120	8,581	7,077	5,790	7,785	8,768	10,386	8,551

1 metric-ton=1.10231 tons

1 metric-ton=1000 Kg

Enclosure 4 Liquid fuel consumption data for bar chart in Enclosure 2 and spreadsheet calculations of GHG emissions for the AES plant between years 2005 and 2016 for GHG emission curves shown in Enclosure 6.

ENCLOSURE 5

CALCULATE CO_2e EMISSIONS AND COMPARE WITH BASELINE IN GHG REDUCTION PLAN														
Ref	Source Derivation	Calendar Year ->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(a)		CO_2e Emissions Solid Fuel & Sorbent (kg)	1,414,060,945	1,367,575,770	1,420,484,467	1,515,647,949	1,451,419,257	1,513,798,222	1,383,577,824	1,432,780,801	1,338,846,416	1,591,718,377	1,492,066,877	1,589,757,993
(b)		CO_2e Emissions Liquid Fuel (kg)	14,917,320	10,080,912	6,523,344	8,080,667	10,994,666	7,784,652	6,420,576	5,252,952	7,062,392	7,954,941	9,422,111	7,757,744
(c)	(a)+(b)	Total CO_2e Emissions (kg)	1,428,978,265	1,377,656,682	1,427,007,811	1,523,728,616	1,462,413,922	1,521,582,875	1,389,998,400	1,438,033,753	1,345,908,808	1,599,673,319	1,501,488,988	1,597,515,737
(d)	$(c)/10^3$	Total CO_2e Emissions (metric-tons)	1,428,978	1,377,657	1,427,008	1,523,729	1,462,414	1,521,583	1,389,998.400	1,438,033.753	1,345,909	1,599,673	1,501,489	1,597,516
(c)	**AES GHG Plan**	**AES CO_2e Emissions (metric-tons)**						**1,525,526**						
(d)		**Deviation from CAB Calculations**						**0.259%**						
(e)	(d)*1.10231	**CO_2e Emissions (tpy)**	**1,575,177**	**1,518,605**	**1,573,005**	**1,679,621**	**1,612,033**	**1,677,256**	**1,532,209**	**1,585,159**	**1,483,609**	**1,763,336**	**1,655,106**	**1,760,958**
CALCULATE CO_2e CAP AND COMPARE WITH INDIVIDUAL CAP IN GHG REDUCTION PLAN														
(f)		Biogenic CO_2e Emissions TDF (metric-tons)	3,673	4,758	3,003	2,624	4,670	0	0	11	2,509	784	2,931	2,439.68
(g)	(f)*1.10231	Biogenic CO_2e Emissions TDF (tons)	4,049	5,245	3,310	2,892	5,148	0	0	13	2,765	864	3,231	2,689
(h)	(e)-(g)	Total CO_2e Emissions Excluding Biogenic TDF (tons)	1,571,128	1,513,360	1,569,695	1,676,729	1,606,886	1,677,256	1,532,209	1,585,146	1,480,843	1,762,472	1,651,875	1,758,268
(i)	(h)/1.10231	Total CO_2e Emissions Excluding Biogenic TDF (metric tons)	1,425,305	1,372,899	1,424,005	1,521,105	1,457,744	1,521,583	1,389,998	1,438,022	1,343,400	1,598,890	1,498,558	1,595,076
(j)	(i)*(1,000)	Total CO_2e Emissions Excluding Biogenic TDF (kg)	1,425,304,892	1,372,898,769	1,424,005,286	1,521,104,958	1,457,743,991	1,521,582,875	1,389,998,400	1,438,022,343	1,343,400,185	1,598,889,633	1,498,558,003	1,595,076,053
(i)	(1.00+0.16)*((e)-(g))	2020 CO_2e Emissions Cap (tons)	1,319,747	1,271,222	1,318,544	1,408,453	1,349,784	1,408,895	1,287,056	1,331,523	1,243,909	1,480,477	1,387,575	1,476,945
(j)	**AES GHG Plan**	**AES CO_2e Emissions CAP (tons)**						**1,412,548**						
	(i)-(j)	Lower (-) or Higher than CAB Estimate (tons)						3,653						

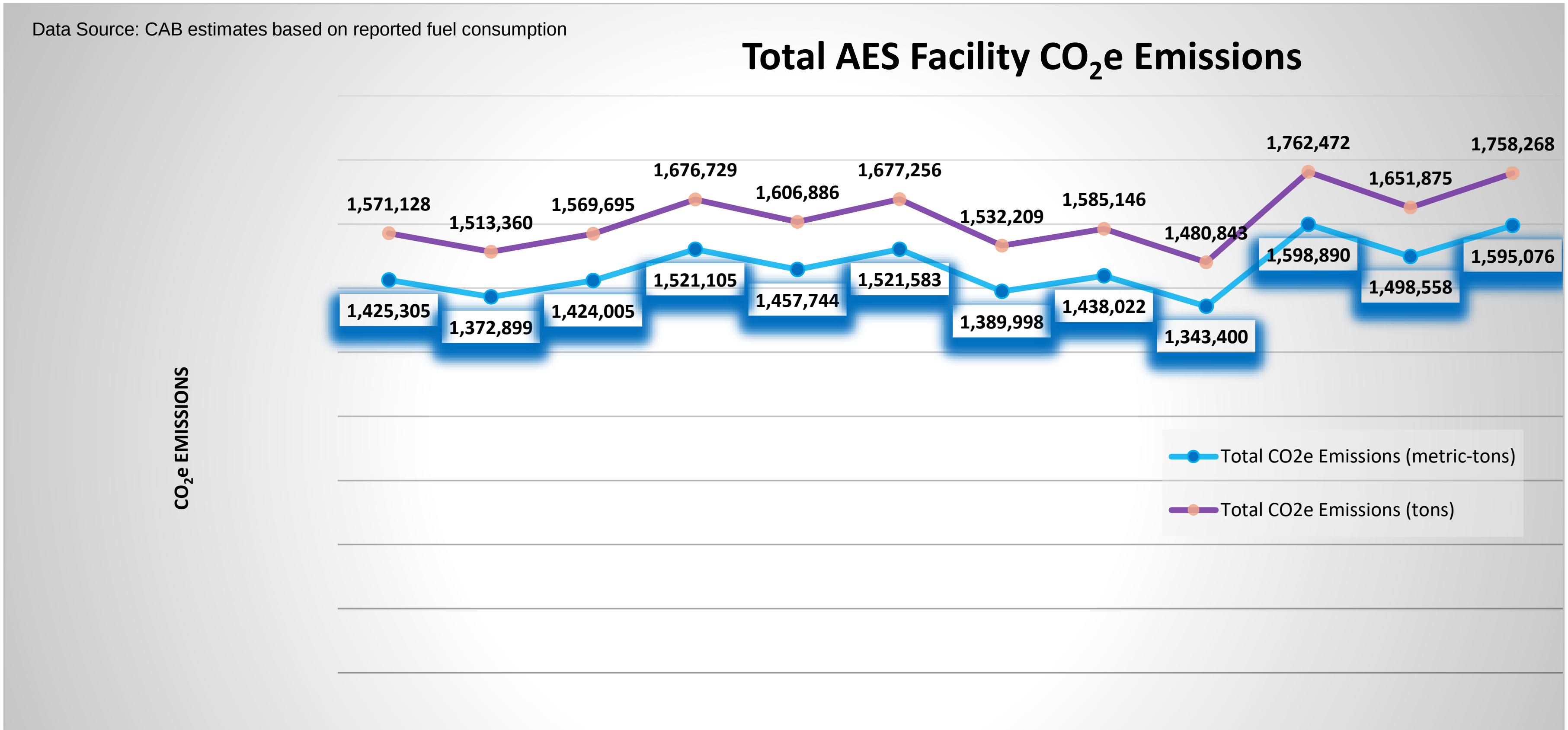
a: Based on information from https://www.betalabservices.com/renewable-carbon/tire-derived-fuels.html that biomass fraction of scrap tires are 18.3% on average for used passenger car tires and 29.1% on average for used truck tires. The average of the two percent averages is 23.7%. The percentages of biomass in the tire dirived fuel (TDF) was based on ASTM D6866 test methods to measure the biogenic carbon fraction of TDF.

1 metric-ton=1.10231 tons

1 metric-ton=1,000 kg

Enclosure 5 Total combined solid fuel, limestone sorbent, and liquid fuel consumption data and spreadsheet calculations of GHG emissions for the AES plant between years 2005 and 2016 to prepare GHG emission curves shown in Enclosure 6.

ENCLOSURE 6



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total CO2e Emissions (metric-tons)	1,425,305	1,372,899	1,424,005	1,521,105	1,457,744	1,521,583	1,389,998	1,438,022	1,343,400	1,598,890	1,498,558	1,595,076
Total CO2e Emissions (tons)	1,571,128	1,513,360	1,569,695	1,676,729	1,606,886	1,677,256	1,532,209	1,585,146	1,480,843	1,762,472	1,651,875	1,758,268

Enclosure 6 Total AES facility GHG emissions between years 2005 and 2016. Blue curve provides emissions in metric tons with numbers that are highlighted in blue. Purple curve shows GHG emissions in short tons with numbers that are not highlighted.

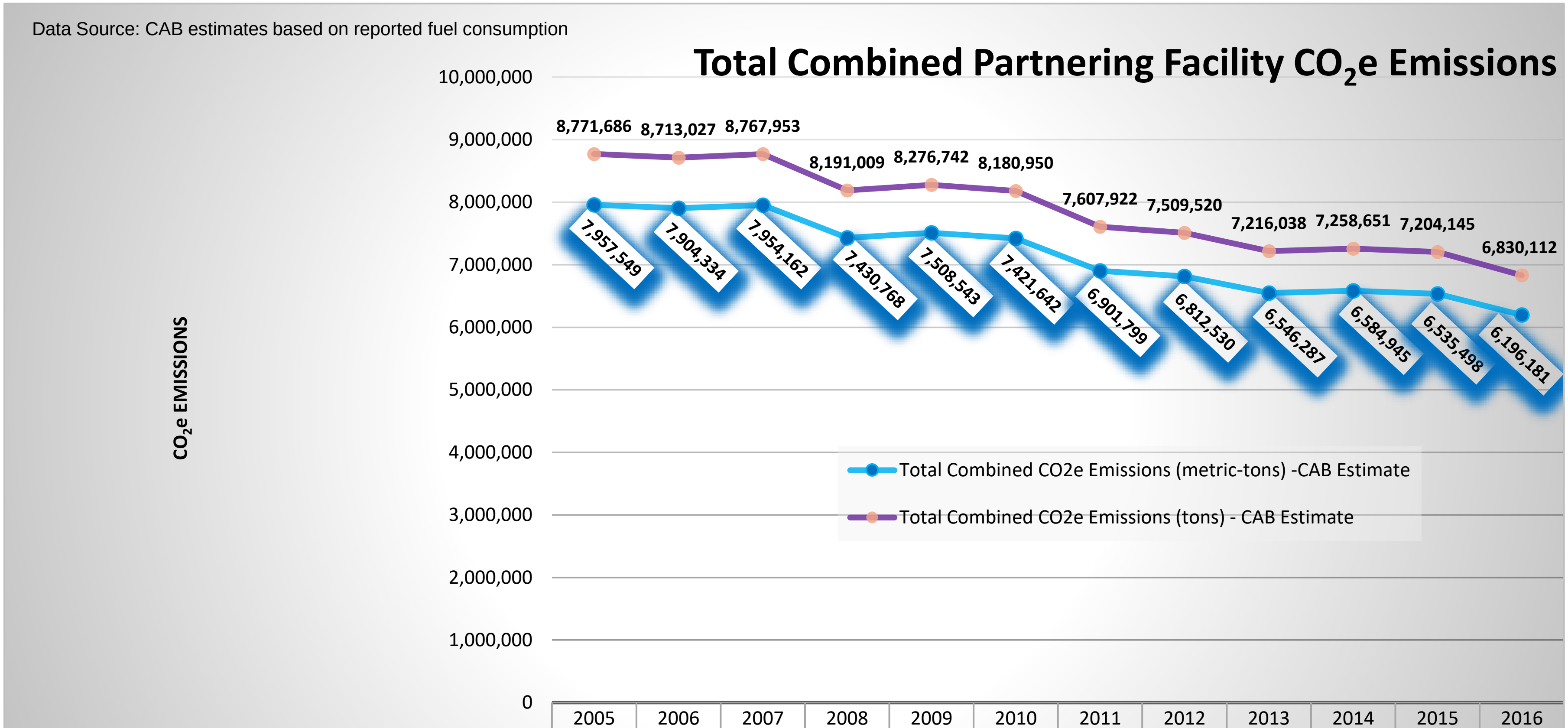
ENCLOSURE 7

TOTAL COMBINED CO_2e FACILITY-WIDE EMISSIONS														
Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(a)	CAB estimates	AES Total CO_2e Emissions Excluding Biogenic CO_2 Portion fom Burning TDF (metric-tons)	1,425,305	1,372,899	1,424,005	1,521,105	1,457,744	1,521,583	1,389,998	1,438,022	1,343,400	1,598,890	1,498,558	1,595,076
(b)	(a)*1.10231	AES Total CO_2e Emissions Excluding Biogenic CO_2 Portion from Burning TDF (tons)	1,571,128	1,513,360	1,569,695	1,676,729	1,606,886	1,677,256	1,532,209	1,585,146	1,480,843	1,762,472	1,651,875	1,758,268
(c)	(1.00+0.16)*(a)	2020 CO_2e Emissions Cap (metric-tons)						1,278,130						
(d)	(1.00+0.16)*(b)	2020 CO_2e Emissions Cap (tons)						**1,408,895**						
(e)	**AES GHG Plan**	**AES Baseline Emissions (tons)**						**1,681,605**						
(f)	**AES GHG Plan**	**AES CO_2e Emissions CAP (tons)**						**1,412,548**						
(g)	(f)-(d)	Higher or Lower (-) than CAB Estimated Cap (tons)						3,653						
(h)	(g)/(d)	Higher or Lower (-) than CAB Estimated Cap (%)						0.26%						

1 metric-ton=1.10231 tons

1 metric-ton=1000 Kg

Enclosure 7 Total combined AES facility-wide GHG emissions between years 2005 and 2016. The data from Enclosure 7 was used to prepare curves in Enclosure 6.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Combined CO2e Emissions (metric-tons) -CAB Estimate	7,957,549	7,904,334	7,954,162	7,430,768	7,508,543	7,421,642	6,901,799	6,812,530	6,546,287	6,584,945	6,535,498	6,196,181
Total Combined CO2e Emissions (tons) - CAB Estimate	8,771,686	8,713,027	8,767,953	8,191,009	8,276,742	8,180,950	7,607,922	7,509,520	7,216,038	7,258,651	7,204,145	6,830,112

Enclosure 8 Curves showing total combined GHG emissions from Shipman Generating Station and all partnering facilities that include three (3) IPPs and ten (10) facilities operated by the Hawaiian Electric Companies. Blue curve shows GHG emissions with numbers in metric tons that are outlined in blue. Purple curve shows GHG emissions with numbers in short tons that are not highlighted.

Enclosure (9): Maximum Potential Greenhouse Gas Emissions

AES Cogeneration Plant GHG Emissions						
Unit	**Heat Input (MMBtu/hr)**	**Fuel**	**GHG**	**GHG Mass-Based Emissions[a,b] (TPY)**	**GWP**	**GHG CO_2e Based Emissions (TPY)**
Boiler A & B	2,150	Anthracite Coal	CO_2	2,152,679	1	2,152,679
			CH_4	228.4	25	5,709
			N_2O	33.2	298	9,899
Limestone Dryer 1A	4.75	fuel oil No. 2	CO_2	3,392	1	3,392
			CH_4	0.1	25	3
			N_2O	0.03	298	8
Limestone Dryer 1B	4.75	fuel oil No. 2	CO_2	3,392	1	3,392
			CH_4	0.1	25	3
			N_2O	0.03	298	8
Lime Injection Boiler A & B c, d, and e	N/A	Sorbent	CO_2	15,197	1	15,197
					Total ------>	2,190,292

a: Emission Factors are from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases.
b: Limestone CO2 Emissions-Sorbent Methodology:

Limestone CO_2 Emissions-Sorbent Methodology
From 98.33(d)(1): (Eq. C-11)
where:

CO_2=	CO2 emitted from sorbent for the reporting year (metric tons)
S=	Limestone or other sorbent used in the reporting year, from company records (short tons)
R =	The number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R=1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2
MWCO2=	Molecular weight of carbon dioxide (44)
MWS=	Molecular weight of sorbent (100 if calcium carbonate)
0.91=	Conversion factor from short tons to metric tons

c: For 2010 operating year, 6,219 and 5,289 metric tons (6,855 and 5,830 short tons) of CO_2 was emitted by lime injection from Boiler A and B, respectively. Total sorbent CO_2 is 12,685 short tons.
d: Total MMBtu/yr for 2010 based on coal consumption for the boilers is as follows:

Coal:
Boiler A (371,062 ton/yr)(21.14 MMBtu/ton) = 7,844,251 MMBtu/yr
Boiler B (372,570 ton/yr)(21.14 MMBtu/ton) = 7,876,130 MMBtu/yr
Total = 15,720,381 MMBtu/yr

e: Maximum potential CO_2 from sorbent based on proportioning is: (12,685 short tons of sorbent CO_2 based on 2010 data)(18,834,000 MMBtu/15,720,381 MMBtu) = 15,197 tons

Enclosure 9 Spreadsheet calculations of maximum potential GHG emissions from the AES cogeneration plant.

APPLICATION AND SUPPORTING INFORMATION

Re: Hawaiian Electric GHG ERP Draft Revision of Permit

Hamamoto, Dale

Tue 6/9/2020 9:26 AM

To: Peterson, Sharon
Cc: Madsen, Michael A; Takamoto, Clayton ; Tandi, Myrna; Kimura, Karin ; Smith, Lee

Hi Sharon,

With regards to your question, "Will the Partners have another opportunity to review the draft permit with DOH's revisions before it goes out for public comment?".

The answer to your question is yes. We are reviewing Hawaiian Electric comments and we plan to incorporate the final agreed upon changes into the draft permit modifications for all partnering facilities. Once completed, I'll be sending all the permits out for a final review.

In hindsight, I believe we need to clearly define the net generating capacity of the Puna Geothermal Venture facility that preceded its shutdown. I'll be doing further research and validation on this today.

Please let me know if you have further questions and/or comments.

Respectfully,

Dale

From: Peterson, Sharon
Sent: Tuesday, June 9, 2020 8:59 AM
To: Hamamoto, Dale
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna; Kimura, Karin; Smith, Lee

Subject: [EXTERNAL] RE: Hawaiian Electric GHG ERP Draft Revision of Permit

Hi Dale,

Hawaiian Electric circulated the draft CSP 0548-01-C you provided on May 29, 2020 to the Hawaiian Electric GHG ERP partners (Partners) for review and comment. Please see the a ached documents with comments prepared by the Partners. The a ached PDF includes proposed revisions to the *Calendar Year 2019* (renamed by the partners as ERP Partnership 2019 CSP Limits) and *Calendar Year 2020 and Beyond* (renamed by the partners as ERP Partnership Baseline CO2e Emissions) tables that are located in A achment II – GHG, Section C.1. (GHG Emissions Caps) of the draft CSP. The a ached Word document includes proposed revisions to A achment II – GHG, Section C.3. (Alternate Operating Scenarios) of the draft CSP.

Will the Partners have another opportunity to review the draft permit with DOH's revisions before it goes out for public comment? Due to the number of redlines we would like a day to review for accuracy after the permit is revised.

Please let me know if you have any questions.

Thanks,

SHARON PETERSON
Principal Environmental Scientist, Air Quality & Noise

O: 808.543.4521 | **M:** 808.430.6885

Hawaiian Electric
PO Box 2750, Honolulu, HI 96840

From: Hamamoto, Dale **Sent:** Monday, June 08, 2020 8:45 AM
To: Peterson, Sharon
Cc: Madsen, Michael A; Takamoto, Clayton ; Tandi, Myrna
Subject: Re: Hawaiian Electric GHG ERP Draft Revision of Permit

Sharon,

OK Great!

Thanks,

Dale

From: Peterson, Sharon
Sent: Monday, June 8, 2020 8:43 AM
To: Hamamoto, Dale
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: [EXTERNAL] RE: Hawaiian Electric GHG ERP Draft Revision of Permit

Hi Dale,

We are waiting for final review of the comments and revised charts from the partners. We should have the comments for you tomorrow, 6/9.

Thanks,
Sharon

From: Hamamoto, Dale
Sent: Monday, June 08, 2020 8:20 AM
To: Peterson, Sharon
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: Re: Hawaiian Electric GHG ERP Draft Revision of Permit

Sharon,

Please let us know how much additional time you will need.

Dale

From: Peterson, Sharon
Sent: Monday, June 8, 2020 8:14 AM

To: Hamamoto, Dale
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: [EXTERNAL] RE: Hawaiian Electric GHG ERP Draft Revision of Permit

Hi Dale,

The draft permit was circulated to the partners for their review and comment and we are still working on the comments. I'll provide you with updates as I hear about the progress, but I think we are pre y close to having a response ready for you. I'm sorry, I thought you were aware of our need for additional time. Going forward I will communicate this with you directly.

Thanks,
Sharon

From: Hamamoto, Dale
Sent: Monday, June 08, 2020 7:35 AM
To: Peterson, Sharon
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: Re: Hawaiian Electric GHG ERP Draft Revision of Permit

Hi Sharon,

Please update us on the status of Hawaiian Electric's review of DOH's re-draft to CSP 0548-01-C?

Dale

From: Peterson, Sharon
Sent: Friday, May 29, 2020 3:26 PM
To: Hamamoto, Dale
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: [EXTERNAL] RE: Hawaiian Electric GHG ERP Draft Revision of Permit

Hi Dale,

We've received the draft permit. We will review and get back to you with any comments by June 5, 2020.

Have a great weekend!

Thanks,
Sharon

From: Hamamoto, Dale
Sent: Friday, May 29, 2020 3:17 PM
To: Peterson, Sharon
Cc: Madsen, Michael A; Takamoto, Clayton; Tandi, Myrna
Subject: Hawaiian Electric GHG ERP Draft Revision of Permit

[This email is coming from an EXTERNAL source. Please use caution when opening attachments or links in suspicious email.]

Good Afternoon Sharon.

Hope your day has been pleasant.

In response to Hawaiian Electric's email response on May 22, 2020 and prior correspondence, the Department of Health Clean Air Branch (DOH) is sending a another draft of CSP No. 0548-01-C for Hawaiian Electric's review and comment. Significant changes include the addition of alternate operating scenarios to allow for the approval of changes to the emission caps due to the shutdown and resurrection of Puna Geothermal Venture (PGV) facility and the reallocation of emission caps to the numbers that was submitted in your email response on May 22, 2020.

To expedite the process, the DOH is using the draft permit for Hawaiian Electric's Campbell Industrial Park as a template for the remaining partnering permits. The DOH requests for Hawaiian Electric's comments by April 5, 2020.

If you have any questions regarding this request, please feel free to contact me.

Very Respectfully,

Dale Hamamoto
Environmental Engineer
State of Hawaii, Department of Health
Clean Air Branch
Phone: (808) 586-4200

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ERP Partnership Baseline CO_2e Emissions

Company	Covered Source	CO2e Emissions[1,2] (metric tpy)	CO2e Emissions[1,2] (tpy)	CSP Limits With AES Reductions[4] CO2e Reduction (%)	CO2e Reduction (tpy)	CO2e Limit (tpy)
Hawaiian Electric (HE)	Kahe	2,518,411	2,776,073	20.6%	572,556	2,203,516
	Waiau	974,642	1,074,359	18.3%	196,309	878,050
	Honolulu	121,208	133,609	100.0%	133,609	0
	CIPGS[3]	13,559	14,946	-726.3%	-108,558	123,504
HE Subtotal		3,627,821	3,998,988	19.9%	793,917	3,205,071
Maui Electric (ME)	Kahului	209,414	230,839	33.0%	76,206	154,633
	Maalaea	562,012	619,512	25.8%	159,648	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 (HL)	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
HL Subtotal		475,413	524,053	14.8%	77,642	446,411
Hawaiian Electric Companies		**4,900,275**	**5,401,629**	**20.5%**	**1,109,195**	**4,292,433**
AES Hawai‘i		**1,525,526**	**1,681,605**	16.0%	269,057	**1,412,548**
Hamakua Energy Power		**165,992**	**182,975**	16.0%	29,276	**153,699**
Kalaeloa Partners, LP		**993,198**	**1,094,813**	-6.4%	-69,764	**1,164,577**
Partnership Total		**7,584,991**	**8,361,022**	**16.00%**	**1,337,764**	**7,023,257** [5]

Notes:

(1) Excludes biogenic CO_2 emissions per HAR §11-60.1-204(d)(6)(B).

(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.

(4) Includes AES' voluntary reduction of 10,000 tons and 16% GHG emissions distributed to Oahu partners except AES and Honolulu.

(5) Does not include additional requested PGV allowances per HAR 11-60.1-204(h)(5).

Revision Date: June 8, 2020

ERP Partnership 2019 CSP Limits

Company	Covered Source	PGV 100% Operation CO_2e Emissions (1,2) (tpy)	With PGV allowance CO2e Limit Adjustment (tpy)	With PGV allowance CO2e Limit (4) (tpy)
Hawaiian Electric (HE)	Kahe	2,133,752	0	2,133,752
	Waiau	808,286	0	808,286
	Honolulu	0	0	0
	CIPGS(3)	53,740	0	53,740
HE Subtotal		2,995,778	0	2,995,778
Maui Electric (ME)	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
Hawaiʻi Electric Light (HL)	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
HL Subtotal		446,411	87,880	534,291
Hawaiian Electric Companies		**4,083,140**	**87,880**	**4,171,020**
AES Hawaiʻi		**1,691,605**	0	**1,691,605**
Hamakua Energy Power		**153,699**	97,524	**251,223** (6)
Kalaeloa Partners, LP		**1,094,813**	0	**1,094,813**
Partnership Total		**7,023,257**	**185,404**	**7,208,661** (5)

Notes:

(1) Excludes biogenic CO_2 emissions per HAR §11-60.1-204(d)(6)(B).

(2) Selections of facility emissions baselines are described in the individual GHG Emission Reduction Plans for the Hawaiian AES Hawaiʻi, 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.

(4) Does not include AES' 2020 voluntary reductions of 10,000 tons and 16% GHG emissions. PGV allowance is distributed to Hawaiʻi Island partners, except Shipman.

(5) Includes requested PGV allowance of 185,404 tons. The GHG Partners reserve the right to request an additional allowance for delays in renewable energy projects that are beyond their reasonable control.

(6) Hamakua's position is that the emission cap must remain at this cap amount beyond 2019 until such time as PGV is able to generate and transmit power to Hawaiʻi Electric Light's grid at pre-eruption amount.

JUL 29 2019

JUL 26 2019

ANTHONY KOYAMATSU
Director
Environmental Division

Hawaiian Electric
Campbell Industrial Park

July 26, 2019

CERTIFIED MAIL NO. 7016 2710 0000 8739 2030
RETURN RECEIPT REQUESTED

Ms. Marianne Rossio, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject: **Updated Greenhouse Gas Emissions Reduction Plan**
Second Revision to Significant Modification Applications
Covered Source Permit Nos. 0548-01-C, 0240-01-C, 0238-01-C, 0239-01-C, 0234-01-C, 0007-01-C, 0235-01-C, 0232-01-C, 0067-01-C, and 0031-04-C
Attachment II-GHG
Hawaiian Electric Company, Inc.
Hawai'i Electric Light Company, Inc.
Maui Electric Company, Ltd.

Hawaiian Electric Company, Inc. (Hawaiian Electric), Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), and Maui Electric Company, Ltd. (Maui Electric), collectively referred to as "Companies", hereby submits an updated Greenhouse Gas Emissions Reduction Plan (GHG ERP) and the second revision to the significant modification applications dated March 28, 2018. These revisions reflect responses received from Department of Heath to comments the Companies submitted on May 15, 2019 concerning the proposed CSPs.

The Companies request that DOH modify the partnership aggregate and Hawai'i Island site-specific emissions caps for calendar year 2019, as detailed in Attachment II – GHG, Special Condition C.1.b of the CIP CSP (Permit No. 0548-01-C), and cross-referenced in each of the GHG CSPs, to reflect the loss of renewable energy from Puna Geothermal Venture (PGV), which had previously been included in the calculations in the Companies' GHG ERP.

Table 1 attached shows the proposed cap adjustment as presented in Table A-2 of the enclosed GHG ERP. The derivation of the cap addition is explained in the enclosed GHG ERP Attachment F.

Revisions were also made to item I.E of Form S-6 for all the GHG ERP partnering facilities to update the reference to the corresponding GHG ERP. Enclosed is Form S-6 for each above reference facilities which are direct replacements for the Form S-6 in the applications previously submitted to the Department of Health. No other changes are proposed with this submittal.

If you have any questions regarding this submittal, please contact Myrna Tandi at 543-4535 or myrna.tandi@hawaiianelectric.com.

Sincerely,

Attachment: (1) Table 1: Proposed 2019 GHG Limits for PGV Outage

Enclosures: (1) Updated Greenhouse Gas Emissions Reduction Plan dated July 26, 2019
(2) Revised Form S-6 for Kahe, Waiau, Honolulu, CIP, Kahului, Maalaea, Palaau, Kanoelehua-Hill, Keahole, and Puna Generating Stations

Ec (w/Encl.): Michael Madsen, Department of Health, michael.madsen@doh.hawaii.gov

Cc (w/Encl.): **RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Certified Mail No.7016 2710 0000 8739 2047]
Chief, Permits Office, Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

Table 1
Proposed 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)
HE	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
ME	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
HE	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
HL 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**

JUL 29 2019

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Certification

This certification applies to the July 26, 2019 update of the **Greenhouse Gas Emissions Reduction Plan for the Hawaiian Electric Companies** *that is being submitted to the Department of Health in accordance with HAR 11-60.1 Subchapter 11.*

I certify that I have knowledge of the facts set forth therein, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Name: Robert C. Isler
Title: Vice President, Power Supply, Hawaiian Electric Company

Signature: Rob C. Isler Date: 7/24/19

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

JUL 29 2019

JUL 26 2019

Greenhouse Gas Emissions Reduction Plan for the Hawaiian Electric Companies

Submitted to Hawai‘i Department of Health in accordance with HAR 11-60.1 Subchapter 11

July 26, 2019 Update

Table of Contents

Record of Revisions

Revision No.	Date	Revisions
0	06/30/2015	Original submission to DOH
1	09/08/2017	Designate Campbell Industrial Park Generating Station (CIPGS) CSP No. 0548-01-C as the Main Permit for Partnership; update facility-specific GHG caps in Table A-1 based on latest forecasts; miscellaneous text updates.
2	02/28/2018	Add AES Hawai'i, Kalaeloa Partners LP (KPLP), and Hamakua Energy Power (HEP) as partners; revise GHG Partnership section; add Monitoring explanation.
3	10/15/2018	Change KPLP baseline and cap in Table A-1 to Tier 3 basis per agreement with DOH. Updates to Table 1 and text to address DOH comments rec'd 9/21/2018.
4	05/15/2019	Changes for consistency with CSP comments. Adjust 2019 Hawai'i Electric Light, HEP, and aggregate GHG caps for loss of PGV. Table A-2 added.
5	07/26/2019	Adjust 2019 Hawai'i Electric Light, HEP, and aggregate GHG caps for loss of PGV in accordance with response to comments received from DOH. Attachment F added.

Introduction

Hawaiian Electric Company, Inc. (Hawaiian Electric) and its subsidiaries, Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light) and Maui Electric Company, Ltd. (Maui Electric), (collectively, "Hawaiian Electric Companies" or "Companies") support Hawai'i's goal established in Act 234 of lowering GHG emissions in the state to 1990 levels.

In accordance with Hawai'i Administrative Rules (HAR) under §11-60.1 Subchapter 11, which were adopted to implement Act 234, facilities that have the potential to emit more than 100,000 tons per year of CO_2e (carbon dioxide equivalent) emissions are designated as "Affected Sources." Affected Sources are required to reduce their GHG emissions at least 16% from their 2010 baseline levels by 2020 and thereafter unless the owner or operator can substantiate that a 16% reduction is unattainable and Hawai'i Department of Health (DOH) approves a lesser reduction.[1] The Act 234 regulations also allow Affected Sources to partner with one another to combine their facility-wide GHG emissions caps to leverage emission reductions among partnering facilities to meet the combined GHG emissions caps.[2]

The Hawaiian Electric Companies operated eleven generating facilities in 2010 that each had the potential to emit more than 100,000 tons per year of CO2e and, thus, qualify as Affected Sources. Act 234 regulations require an Affected Source to prepare a GHG Emissions Reduction Plan (ERP) that is used by DOH to set the Affected Source's CO_2e emissions cap. The ERP also demonstrates how that cap will be met by 2020. The Hawaiian Electric Companies have prepared this ERP to satisfy that requirement.

The Hawaiian Electric Companies acquire power from Independent Power Producers (IPPs) and from renewable energy sources (e.g., rooftop solar panels, wind farms, utility scale solar installations) that are used to meet customer demand. In the event an IPP has unplanned outages or there is reduced energy output from renewable sources (e.g., due to cloudy or rainy weather, lack of wind, etc.), the Hawaiian Electric Companies must make up for the shortfall by increasing generation from other generating sources. Historically, the shortfall has been made up by the Companies' Affected Sources, thereby increasing their GHG emissions. In the future, the commissioning of new, rapid-response generators such as the Schofield Generating Station in 2018 as well as battery energy storage systems (BESS) charged by renewable energy sources will allow shifting some of that load to facilities that have lower GHG emissions.

[1] HAR 11-60.1-204(c)

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

GHG Reduction Partnership

This section explains the partnership approach used by the Hawaiian Electric Companies and its Partners in 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 must generate more power than planned to make up for the shortfall. A scheduled or unscheduled outage that takes a major generating unit offline for an extended period 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 upsets that are a natural part of system operation.

For these reasons, the Hawaiian Electric Companies and three major Independent Power Producers (IPPs) have elected to use the partnering provisions in Act 234 Regulations[3] to create a Partnership involving all eleven of the Hawaiian Electric Companies' Affected Sources, the Hamakua Energy Power (HEP) facility, the AES Hawai'i facility, and the Kalaeloa Partners LP (KPLP) facility (collectively "Partnership Facilities" or "Partnership"). The Partnership has an overall GHG emissions cap that it commits to attain. Individual partnering facilities have site-specific GHG emissions reduction goals that are used to apportion penalties that may be assessed in the event the overall GHG emissions cap is exceeded. The DOH will include the site-specific goals as GHG emissions 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 GHG emissions reduction targets for the Partnership Facilities are listed in Tables A-1 and A-2 of Attachment A. The two tables present alternative operating scenarios with and without Puna Geothermal Venture (PGV) operating, as explained further in the next section. The Power Supply Improvement Plan (PSIP) for the Hawaiian Electric Companies that was approved by the Hawai'i Public Utilities Commission (PUC) on July 14, 2017[4] is the blueprint for how that reduction will be accomplished.

The Hawaiian Electric Companies, HEP, AES Hawai'i, and KPLP are submitting separate ERPs for their facilities. The ERPs share the same GHG emissions reduction goals provided in Table A-1 and A-2, but the individual plans explain the GHG baselines, monitoring, and other plan requirements specific to each partner.

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

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

2019 GHG Cap Adjustments for PGV Outage

PGV was forced to stop generating energy in early 2018 by volcanic activity, removing a substantial amount of renewable energy from the system and significantly increasing GHG emissions from the Hawai'i Electric Light and HEP units that have to offset that lost capacity. In 2017 PGV accounted for 33% of total energy generation on Hawai'i Island and is the largest single renewable energy generator in the State. PGV plans to return to operation but the timing is uncertain because of the significant infrastructure damage that occurred. PGV is not expected to return to operation until at least 2020. Loss of PGV qualifies as a reason for DOH to revise the GHG cap under HAR §11-60.1-204(4): "Renewable energy producers cease operations or fail to meet contractual obligations with the affected source, and there are no reasonable alternatives." There are no renewable alternatives to make up for 38 Megawatts (MW) of firm PGV capacity.

PGV's energy generation is equivalent to 185,404 tons of GHG emissions from the Hawai'i Electric Light and HEP fossil fuel units that must operate more to replace it, as detailed in Attachment F. That was calculated by comparing actual emissions in 2017, the last full year PGV operated, with the 12 months from July 2018 to June 2019 when PGV was offline. Table A-2 in Attachment A assigns those emissions to other generating units in proportion to their July 2018 to June 2019 operation. The Hawaiian Electric Companies propose that the caps in Table A-2 only apply for calendar year 2019 while more renewable energy is integrated into the system. For all succeeding years the caps in Table A-1 will apply.

It should be noted that the Companies have experienced delays beyond their direct control involving several new renewable energy projects anticipated in the PSIP that were counted on to lower GHG emissions. The Companies are not seeking an adjustment for these delays, but they have the effect of increasing GHG emissions more than 100,000 tons above what was expected in the earlier ERPs submitted to DOH.

Even with this cap adjustment the Partnering Facilities commit to doing what they can to hold emissions below the Table A-1 limits in 2019. That may include altering unit dispatch priorities to reduce GHG emissions to the extent practicable although large reductions cannot be expected by that means. Since changing dispatch order may be contrary to minimizing customer costs, some level of PUC approval may be required.

Emission Reduction Plan Required Elements

Hawai'i Administrative Rule (HAR) §11-60.1-204(d) states the GHG Emissions Reduction Plan required of Affected Sources shall at a minimum include the following elements:

(1) ***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....*[5]

Attachment A, Table A-1 lists the baseline GHG emissions for the Partnership Facilities. The Hawaiian Electric Companies' facilities all use 2010 calendar year emissions as their baselines. GHG emissions were calculated using the procedures specified in EPA's Mandatory GHG Reporting Rule (40 CFR Part 98, Subpart C). The Kahe, Waiau, and Honolulu facilities used Tier 3 level calculations specified in §98.33 and the other facilities used Tier 2 level calculations. All baselines shown in Table A-1 for the Hawaiian Electric Companies' facilities are as reported via EPA's e-GGRT system for 2010 except for Campbell Industrial Park Generating Station (CIPGS) and Shipman. For calendar year 2010 CIPGS and Shipman GHG emissions were lower than the 25,000 metric ton reporting threshold under Part 98 so GHG emissions reporting was not required.

(2) ***2020 Facility-wide GHG Emissions Caps.*** *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 [a justification and proposal for an alternative cap]....*

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

[5] HAR 60.1-204(d)(1)

guidelines for GHG Best Available Control Technology analysis and GHG control measures by source type shall be used as applicable for this assessment.[6]

Attachment A, Tables A-1 and A-2 list the overall and facility-specific GHG emissions caps the Partnership Facilities commit to achieving by 2020 to comply with the Rule with all their Affected Sources grouped into one Partnership. The overall GHG emissions cap in Table A-1 reflects a 16% reduction in GHG from their GHG emissions baselines.

Table A-1 shows that the overall GHG emissions reduction target for the Hawaiian Electric Companies is 24.4%, which exceeds the overall 16% GHG emissions reduction for the Partnering Facilities because IPPs will continue to be preferentially dispatched for contractual reasons and because they are the lowest-cost power producers. Most of the generation displaced by renewable energy will come from reduced operation of Hawaiian Electric's Affected Sources.

One of the important benefits of the Partnership for customers is that it allows the GHG emissions reduction goal of Act 234 to be met while maintaining the lowest energy cost to customers.

Monitoring and Reporting to Demonstrate GHG Emissions Reductions

The Hawaiian Electric Companies' facilities will use the same procedures used to establish their GHG baseline emissions, as described in paragraph (1), to calculate their annual GHG emissions and demonstrate the Partnership's compliance with the GHG emissions reduction requirement. GHG emissions for each facility will be reported annually on EPA's e-GGRT system and semi-annually to the DOH.

The Hawaiian Electric Companies' facilities use the GHG emissions calculation procedures specified in 40 CFR Part 98, Subpart C. They are not required to use Continuous Emissions Monitoring Systems (CEMS) for GHG emissions monitoring and do not have all the necessary instrumentation to be able to do so.

(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;

[6] HAR 60.1-204(d)(2)

(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.*[7]

Table 1 lists the potential GHG emissions control options cited above and their feasibility for the Hawaiian Electric Companies. ERP Attachments referenced in Table 1 further describe the GHG emissions control options and discuss their feasibility and costs.

[7] HAR 11-60.1-204(d)(3)

TABLE 1 - EVALUATION OF GHG EMISSIONS CONTROL OPTIONS

	GHG Control Option	Feasibility and Benefit
(A)	Carbon Capture and Storage (CCS)	Not Economically Viable - See Attachment B for details.
(B)	Fuel switching or co-firing fuels (Natural Gas)	Not Feasible – The Hawaiian Electric Companies explored importing liquefied natural gas. However, the PUC rejected that option as part of its decision to deny the merger of the Hawaiian Electric Companies with NextEra. See Attachment C for details about the potential GHG emissions benefits.
(C)	Fuel switching or co-firing fuels (Biofuels)	Not Feasible to do on a large scale – The Hawaiian Electric Companies are currently permitted and are burning limited quantities of biodiesel. Attachment D contains a discussion of the availability and cost of biodiesel.
(D)	Energy efficiency upgrades and combustion improvements	Attachment E summarizes the Hawaiian Electric Companies' evaluation of energy efficiency improvements available to their power generating units. No economically viable improvements were identified that would contribute significantly towards reducing GHG emissions.
(E)	Restrictive operations	If one of the generating facilities in the Hawaiian Electric Companies' electrical grids restricts operation to limit its GHG emissions, other facilities must operate more to meet customer demand so the result is that emissions are redistributed rather than reduced or eliminated. The Partnership concept provides flexibility for lower GHG emitting facilities to operate more to lower overall GHG emissions and Hawaiian Electric intends to do this as much as possible within system and economic constraints. However, the GHG emissions reductions available through this route are limited because the more efficient units (e.g., combined cycle combustion turbines) already operate preferentially because they tend to be lower cost generators.

(F)	Planned upgrades, overhaul, or retirement of equipment	As new renewable energy projects come online, the operation of existing fossil-fueled units can be reduced or ceased. The Hawaiian Electric Companies have deactivated or retired the following fossil-fuel units since the 2010 baseline year: • Shipman S3 and S4. Permanently decommissioned and CSP closed December 31, 2015. • Honolulu H8 and H9. Deactivated January 2014.
(G)	Outstanding regulatory mandates, emission standards, and binding agreements	Hawai'i set a 100 percent Renewable Portfolio Standard (RPS) for electrical generation by 2045. The Hawaiian Electric Companies' December 2016 Power Supply Improvement Plan (PSIP) describes how the Companies intend to accomplish that goal. EPA proposed the Affordable Clean Energy (ACE) Rule on August 31, 2018. It is not clear yet whether it will apply to the Hawaiian Electric Companies' oil-fired generating units. The emphasis of ACE Rule is to improve the efficiency of existing generators through measures to be adopted by the states.
(H)	Other GHG emissions reduction initiatives: Renewable Energy (RE) Projects: Wind, Solar, and Battery Energy Storage Systems (BESS) Deployment of new flexible, rapid response generation to enable more integration of renewable energy sources.	The Hawaiian Electric Companies' main strategy for lowering GHG emissions is to continue replacing fossil-fueled generation with utility-scale and distributed (e.g., rooftop solar) renewable energy sources. The December 2016 PSIP includes additional utility scale RE coming online between 2017 and 2019: Hawaiian Electric - 206.2 MW of new utility scale RE + 70MW BESS Maui Electric - 8.74 MW of new RE + 9MW BESS Hawai'i Electric Light - 3 MW of new RE. The December 2016 PSIP also describes new firm generation projects that provide the rapid response capability needed to work with the varying output from renewables. One of these is the Schofield Generating Station that came online in 2018.

(4) ***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.*[8]

As noted above, Table 1 lists the potential GHG emissions control options and their feasibility. Attachments referenced in Table 1 further describe the GHG emissions control options and discuss their feasibility and costs.

(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,

[8] HAR 11-60.1-204(d)(4)

assumptions, vendor quotes, sample calculations, etc.) to substantiate the control analysis and alternate GHG emissions cap.[9]

As noted above, Table 1 lists the potential GHG emissions control options and their feasibility. Attachments referenced in Table 1 further describe the GHG emissions control options and discuss their feasibility and costs.

(6) ***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.*[10]

The Hawaiian Electric Companies will collectively reduce their GHG emissions 16% from the 2010 baseline year, generally in accordance with the power generation forecasts described in their PSIP that was submitted in December 2016 and accepted by the PUC on July 14, 2017.[11] Although the PSIPs are not enforceable under Chapter 342B, HRS, Air Pollution Control, they do carry the weight of oversight by the PUC and public expectations.

The Hawaiian Electric Companies' GHG emissions reductions will result directly from increased state-wide reliance on renewable energy sources as detailed in the PSIP. The Hawaiian Electric Companies have consistently met, and exceeded, the Renewable Portfolio Standards (RPS) agreed to as part of the Hawai'i Clean Energy Initiative (HCEI). For instance, in 2015 23.2% of the Companies' overall power

[9] HAR 11-60.1-204(d)(5)

[10] HAR 11-60.1-204(d)(6)

[11] Public Utilities Commission of the State of Hawai'i Decision and Order No. 34696. July 14, 2017.

generation was from renewable sources,[12] well ahead of the RPS goal of 15% by 2015.[13] In 2017, 26.8% of the Companies' power generation was from renewable sources. The RPS goals have increased due to House Bill 623, signed into law by Governor David Ige on June 5, 2015, which establishes a new RPS goal of 100% renewables by 2045. In 2017, the GHG emissions from the combined Hawaiian Electric Companies were 20.0% lower than the 2010 baseline year. Continued progress towards the RPS and PSIP goals will assist GHG emissions from power generation to decline further.

As explained in Table 1 and the supporting attachments, the Hawaiian Electric Companies' evaluation of potential GHG emissions control measures identified no additional measures that are technically feasible and cost effective. Accordingly, the Companies do not propose to implement any GHG emissions controls.

As described earlier, the Hawaiian Electric Companies' eleven affected facilities are partnering with three IPPs to meet the GHG emissions reduction target. Table A-1 lists the overall GHG annual emissions limit for the Partnership Facilities along with site-specific GHG emissions limits for each of the Partnering Facilities.

The Hawaiian Electric Companies have designated Campbell Industrial Park Generating Station (CIPGS) as the Main Permit for their affected facilities. The CIPGS CSP will list the Total Partnership GHG emissions cap and the site-specific emissions caps for the Hawaiian Electric Companies' other facilities. The CSPs for the Hawaiian Electric Companies' other facilities will reference the CIPGS CSP for GHG emissions limits.

[12] *2017-2018 Corporate Sustainability Report.* Hawaiian Electric Companies. Page 4.

[13] HRS §269-92(2). It should be noted that the RPS allows affiliated electrical utilities to aggregate their renewable portfolios. HRS §269-93. Accordingly, all GHG emissions reductions referenced in this section represent the aggregate renewable portfolios for Hawaiian Electric, Hawai'i Electric Light, and Maui Electric.

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

		Baseline		CSP Limits		
	Covered	CO2e Emissions		CO2e Reduction		CO2e Limit
Company	Source	(metric tpy)	(tpy)	(%)	(tpy)	(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.

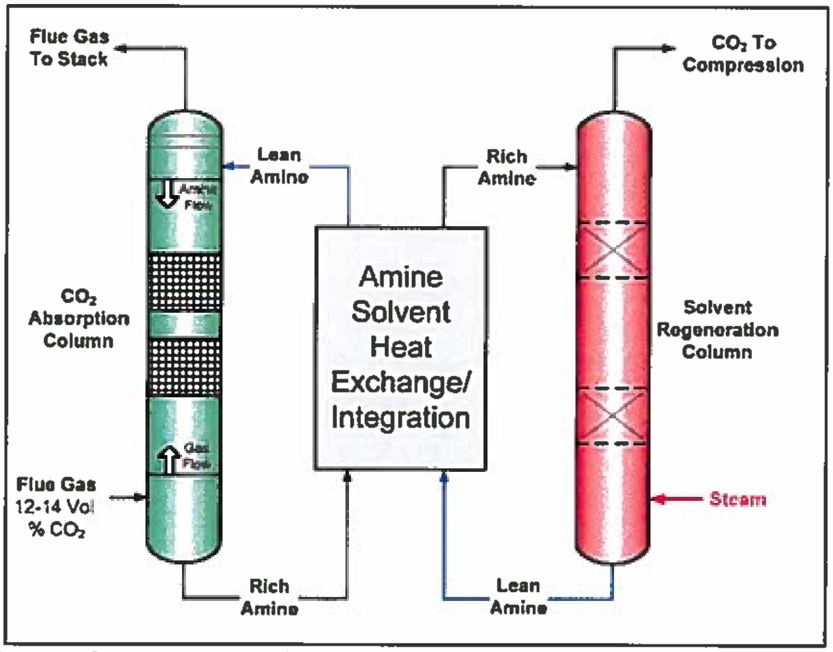
Table A-2: Substitute 2019 GHG Limits for PGV Outage

		PGV 100% Operation	Calendar Year 2019 GHG Limits	
	Covered	CO2e Emissions Limit	GHG Limit Adjustment	CO_2e Emissions Limit
Company	Source	(tpy)	(tpy)	(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**

Carbon Capture and Storage

Carbon Capture and Storage (CCS) is composed of two major functions; CO_2 capture and CO_2 storage. A number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable post-combustion CO_2 capture options, the use of an amine solvent such as monoethanolamine (MEA) it is the most mature and well-documented technology (Kvamsdal et al., 2011). Figure B-1 illustrates the amine-based post-combustion capture process.

FIGURE B-1 SCHEMATIC DIAGRAM OF AMINE-BASED CO_2 CAPTURE PROCESS



Source: Interagency Task Force on Carbon Capture and Storage, 2010

EPA generally considers post-combustion CO_2 capture with an amine solvent to be technically feasible for natural gas fired combined cycle combustion turbines and coal fired power plants. However, this technology has not been demonstrated on simple cycle combustion turbines and reciprocating engines. Part of the reason is that the flue gas temperature from simple cycle turbines and reciprocating engines is much higher than from combined cycle turbines and boilers so the gases have to be cooled prior to scrubbing going to the CO_2 absorption column. While still feasible, that adds cost and makes it less economically practical. A more fundamental difficulty with using amine absorption for combustion turbines of either type as well as reciprocating engines is that the CO_2 concentration in the flue gas is lower than 6 percent. That concentration is much lower than other types of power plants, such as coal fired power plants, where the CO_2 concentration may be as high as 12-15 percent by volume in the post combustion flue gas stream. As a result, the amine system equipment has to be more than twice as large for the same amount of CO_2 captured. That greatly increases the treatment cost. Although significant challenges exist, CCS cost estimates are provided in Tables B-1 and B-2. The data in the tables do not reflect the higher cost associated with treating low-CO_2 concentration flue gases from combustion turbines and reciprocating engines.

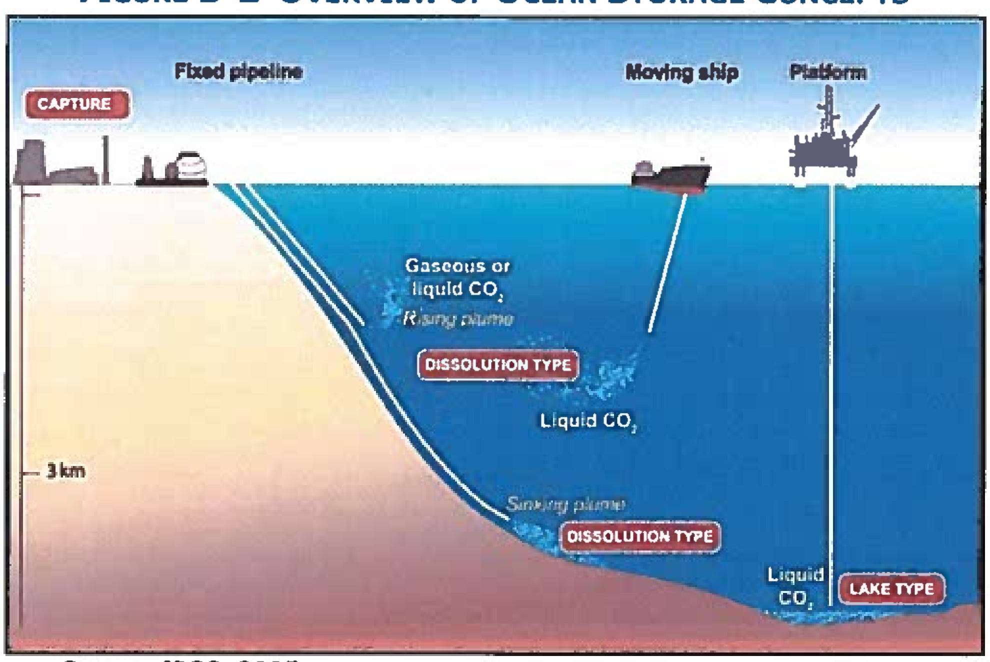
Hawai'i's remote location imposes many additional challenges implementing CO_2 storage that are not present for continental U.S. sources. Hawaiian Electric is not aware of any proven CO_2 geological storage sites on Hawai'i. Therefore, ocean storage, i.e., direct CO_2 release into the ocean water column or onto the deep seafloor, appears to be the most readily available CO_2 storage option.

As shown in Figure B-2, CO_2 ocean storage potentially could be implemented in two ways:

- By injecting and dissolving CO_2 into the water column (typically below 1,000 meters) via a fixed pipeline or a moving ship, or
- By depositing CO_2 via a fixed pipeline or an offshore platform onto the sea floor at depths below 3,000 m, where CO_2 is denser than water and is expected to form a "lake" that would delay dissolution of CO_2 into the surrounding environment.

Ocean storage and its ecological impacts are still in the research phase and the legal status of intentional ocean storage is unknown (Herzog, 2010; IPCC, 2005; Purdy, 2006).

FIGURE B-2 OVERVIEW OF OCEAN STORAGE CONCEPTS



Source: IPCC, 2005

Attachment B – Carbon Capture and Storage

The first step to costing CCS is calculating CO_2 emission rates. CO_2 emissions from power generation are a function of fuel type and the heat rate of the generating unit. Due to the large number of generating units and the various current and future fuel types, the costing is based on typical generating unit configurations.

Table B-1 lists the estimated total annual cost on a $/million Btu (MBtu) basis to add CCS based on fuel type. The estimate includes the amine absorber system cost, the onshore CO_2 storage cost, and the ocean injection cost. The total annual estimated cost ranges from $5.64 to $7.99 per MBtu of heat input.

As noted earlier, due to the absence of suitable subterranean formations, geological storage does not appear to be a viable option in Hawai'i. Even if available, using geological storage instead of ocean storage would not lower the cost. The listed estimated total ocean CO_2 storage cost of $13.80 per ton ($2.00 + $4.81 + $6.99 = $13.80) is actually lower than the estimated total cost for geological storage ($8.53 to $19.51 per ton)[14].

Table B-2 lists the estimated total annual cost for CCS on a $/kW basis for various fuel and generating unit types. These costs range from 7¢ to 10¢ per kWh based on maximum operation. These costs would be higher based on actual operating levels. That means that power cost to customers would have to increase 25% or more from 2016 rates, depending on location, to pay for CCS.

[14] Table 9 of the National Energy Technology Laboratory report "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs" (DOE/NETL-2013/1614), dated March 14, 2013.

TABLE B-1 ESTIMATED TOTAL ANNUAL CCS COST ($/MBTU)

Carbon Capture and Storage (CCS) Component	Cost (S/ton CO_2 Captured)	CO_2 Emissions[1] (lb/MMBtu)	% Captured[2]	CO_2 Emissions Captured (lb/MMBtu)	Total Annual Cost (S/MMBtu)
		No. 6 Fuel Oil			
CO_2 Capture and Compression[3]	93.44	165.6	90%	149	S6.96
Onshore CO_2 Storage[4]	2.00				S0.15
Ship transport to injection ship[4]	4.81				S0.36
Injection ship, pipe and nozzle[4]	6.99				S0.52
Total Cost (Biodiesel)	107.24				S7.99
		No. 2 Fuel Oil			
CO_2 Capture and Compression[3]	93.44	163.1	90%	147	S6.87
Onshore CO_2 Storage[4]	2.00				S0.15
Ship transport to injection ship[4]	4.81				S0.35
Injection ship, pipe and nozzle[4]	6.99				S0.51
Total Cost (Diesel)	107.24				S7.88
		Natural Gas			
CO_2 Capture and Compression[3]	93.44	117.0	90%	105	$4.91
Onshore CO_2 Storage[4]	2.00				S0.11
Ship transport to injection ship[4]	4.81				S0.25
Injection ship, pipe and nozzle[4]	6.99				S0.37
Total Cost (Natural Gas)	107.24				S5.64

Notes:

1. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart C, Table C-1).
2. Typical value for amine absorber systems (Interagency Task Force on Carbon Capture and Storage, 2010; NETL, 2013).
3. The CO_2 capture and compression cost is based on information presented in Figure III-1 of the Report of the Interagency Task Force on CCS, dated August 2010. The listed dollar per ton of CO_2 captured is the cost of applying post-combustion CCS to an existing natural gas fired combined cycle power plant. The listed cost (S103 per metric ton or S93.44 per ton) is based on continuous operation (8,760 hrs per unit per year at base load for each fuel type).
4. Costs are from Table 6.6 of the IPCC Special Report on Carbon Dioxide Capture and Storage, dated 2005.

TABLE B-2 ESTIMATED TOTAL ANNUAL CCS COST ($/KWH)

Unit Type	Typical Heat Rate (Btu/kWh)	Fuel Type	Total Annual Cost ($/MMBtu)	CO_2 Removal Cost ($/kWh)
Boiler	12,000	No. 6 Fuel Oil	$7.99	0.10
		No. 2 Fuel Oil	$7.88	0.09
		Natural Gas	$5.64	0.07
Simple Cycle Combustion Turbine	9,500	No. 2 Fuel Oil	$7.88	0.09
		Natural Gas	$5.64	0.07
Combined Cycle Combustion Turbine	7,500	No. 2 Fuel Oil	$7.88	0.09
		Natural Gas	$5.64	0.07
Reciprocating Engine	8,000	No. 2 Fuel Oil	$7.88	0.09
		Natural Gas	$5.64	0.07

Note - Costs are based on continuous operation at base load. Costs based on actual operating levels would be higher.

References

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Natural Gas Conversion GHG Emissions Reduction

The Hawaiian Electric Companies pursued importation of liquefied natural gas (LNG) to lower fuel costs and air emissions, including GHG. However, after the PUC denied the merger of the Hawaiian Electric Companies with NextEra[15] the Companies withdrew their application for approval of LNG Supply Agreements.

Substitution of natural gas fuel can significantly reduce GHG emissions from power generation. To the extent that LNG replaces no. 2 (diesel) fuel oil and no. 6 fuel oil, GHG emissions are 28 to 30 percent lower per million Btu (MBtu) of fuel heat input as shown by the emissions factors in Table C-1. Net GHG emissions are reduced by a lesser amount, probably in the 25-28% range, because more heat input is typically required from gas than oil for the same amount of power generated. It is unlikely that LNG would make up 100% of the Companies' fuel consumption so the overall GHG reduction would be correspondingly lower.

TABLE C-1 NATURAL GAS CONVERSION CO_2 EMISSIONS REDUCTION CALCULATION

Fuel	GHG Pollutant[1]	Emission Factor[2] (kg/MMBtu)	Global Warming Potential[3]	Total GHG Emissions as CO_2e (lb/MMBtu)
No. 6 Fuel Oil	CO_2	75.10	1	165.6
	N_2O	6.0E-04	298	0.3942
	CH_4	3.0E-03	25	0.1653
			Total CO_2e =	**166.2**
No. 2 Fuel Oil	CO_2	73.96	1	163.1
	N_2O	6.0E-04	298	0.3942
	CH_4	3.0E-03	25	0.1653
			Total CO_2e =	**163.7**
Natural Gas	CO_2	53.06	1	117.0
	N_2O	1.0E-04	298	0.0657
	CH_4	1.0E-03	25	0.0551
			Total CO_2e =	**117.1**
No. 6 Fuel Oil to Natural Gas Reduction = 29.5%				
No. 2 Fuel Oil to Natural Gas Reduction = 28.4%				

Notes:

1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart C, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart A, Table A-1).

[15] Public Utilities Commission of the State of Hawai'i Decision and Order No. 33795. July 15, 2016.

Biofuel Conversion GHG Emissions Reduction

1. Availability

Biodiesel has been used as fuel for power generation on a limited scale but there is not enough supply to replace a significant portion of the fuel consumed by the Hawaiian Electric Companies. According to the U.S. Energy Information Administration (EIA) Biodiesel Production Report for July 2018, biodiesel (as B100) production capacity in Hawai'i was only about 6 million gallons per year (MGY). Campbell Industrial Park (CIPGS) alone burned 7.7 million gallons in 2017. U.S. production capacity was 2370 MGY but only 209 MGY of that was on the west coast where delivery to Hawai'i would be practical. By comparison, the Hawaiian Electric Companies used 370 million gallons of residual and distillate fuels in 2013.

In order for biodiesel to become sufficiently available to provide fuel for the State's electricity needs, dedicated energy crops would be required. But it is uncertain whether those crops would be adequate for the competing fuel needs throughout the State. Furthermore, biodiesel production is constrained by limited land availability and unpredictable financial incentives. A 2010 study on the potential for biofuel production in Hawai'i concluded that biodiesel produced from waste fats, oils, and greases would account for only one half of one percent of current diesel fuel usage (B&V, 2010). The same study estimated the theoretical biodiesel potential from waste oil as 2 to 2.5 million gallons per year (MGY).

Hawaiian Electric recently obtained a contract with Pacific Biodiesel to purchase approximately 3 MGY of biodiesel, primarily for CIPGS. At this time, Pacific Biodiesel is the only producer of biodiesel located in the State of Hawai'i. Another company, Imperium Renewables Hawai'i, announced plans to develop and build a biodiesel plant in Kapolei (O'ahu) several years ago but the project was unsuccessful due to financial reasons. Subsequently, the PUC rejected Hawaiian Electric's proposal to import biodiesel from Imperium's production plant in Washington State because of high costs. To the extent possible, Hawaiian Electric and the PUC would prefer to use locally-produced biofuels. But there simply is not enough biodiesel supply available to significantly lower Hawaiian Electric's greenhouse gas emissions without drastically increasing the cost.

2. Cost

Table D-1 summarizes Hawaiian Electric's April 2015 fuel price forecasts. Historically, biodiesel has not been economically competitive compared to petroleum diesel without some type of governmental incentive. Our forecast shows that through 2019, the price of biodiesel will be approximately double that of our current fuel mix.

In addition to fuel cost, capital cost would be necessary to provide the infrastructure for receiving and storing biodiesel. Indirect costs such as permitting, performance testing, and engineering would likely add to the overall cost of switching to biodiesel. From an energy standpoint, biodiesel is similar to traditional diesel but contains about 7-10% less energy per gallon. Thus, the cost of biodiesel compared to diesel is higher but the energy content is lower.

Attachment D – Biofuel Conversion GHG Emissions Reduction

Biodiesel prices are expected to continue to rise. Although current generation biodiesel production facilities are more efficient and benefit from economies of scale, feedstock costs have remained high (B&V, 2010). Generally, waste oils are the least expensive but are not always available in large quantities. Furthermore, the U.S. biodiesel industry is highly dependent on financial incentives such as the Federal blender tax credit. The unpredictability of the biofuel market does not align with Hawaiian Electric's priority to provide reliable and low cost electricity. Further, we believe that it is questionable whether the PUC will approve large-scale conversions to biodiesel because of the potential cost impact on the Companies' customers.

Table D-1 Biodiesel Fuel Cost Comparison

Hawaiian Electric's 2018 Fuel Price Forecast				
	$/million Btu			
Year	No. 2 Diesel	LSFO	ULSD	Biodiesel
2018	15.82	13.08	16.88	31.84
2019	14.96	12.17	16.02	31.76
2020	15.86	12.99	16.96	32.93
2021	16.20	13.26	17.32	33.71

References

EIA (U.S. Energy Information Administration), 2015. "Monthly Biodiesel Production Report," dated March 2015.

B&V (Black and Veatch Corp.), 2010. "The Potential for Biofuels Production in Hawai'i," dated January 2010.

Hawaiian Electric, 2018 Fuel Price Forecast. Received from C. Reyes 7/6/2018.

Potential Energy Efficiency Improvements

Improving the efficiency when fuel energy is converted to usable power output reduces the amount of fuel that has to be combusted to satisfy power demand, in turn decreasing the emissions of greenhouse gases and other air pollutants that are created in the combustion process. Additionally, improved energy efficiency reduces the cost of power generation because of the lower fuel requirement.

Energy efficiency of power generating units can be improved though changes to technology (equipment), processes, and practices. But most of the cost-effective improvements available to power generators have already been made to reduce fuel cost since fuel is such a large part of the total cost of power generation. That is especially true for Electrical Generating Units (EGU) like Hawaiian Electric's that burn oil, which is a relatively high cost fuel. Energy efficiency improvement is one of the four Building Blocks that EPA relied on to develop its proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.*[16] In the preamble to the proposed rule EPA stated that they decided not to include efficiency improvement by oil-fired EGUs as an element of their Best System for Emissions Reduction (BSER) evaluation for GHG emissions because the potential GHG reductions are small compared to the reductions available from other types of power generation.[17]

Nevertheless, potential energy efficiency improvements for the Hawaiian Electric Companies' boilers, combustion turbines, and diesel electric generator sets are discussed in this section.

Boilers

The major portion of the Hawaiian Electric Companies' power generation comes from boilers that power steam turbine electric generators. The Hawaiian Electric Companies operate their boilers as efficiently as practicable. An important incentive for doing so is that the PUC establishes efficiency standards that must be met for the Company to fully recover the cost of the fuel used in power generation. Hawaiian Electric assures that its boilers operate at optimal energy efficiency a number of ways. One is by daily tracking and reporting of Heat Rate (HR) for each unit. Heat Rate, a measure of overall power generation efficiency that is commonly used in the power generation industry, is the ratio of the total fuel energy input divided by the net amount of power exported to customers, usually reported as Btu of fuel energy consumed per Kilowatt-hour of power exported (Btu/KWh). The lower the Heat Rate, the more efficiently the unit is operating. Heat Rate trends are a sensitive indicator of efficiency changes somewhere in the system. The Hawaiian Electric Companies also have aggressive Heat Rate improvement programs that follow the guidelines developed by the Electric Power Research

[16] 79 Fed. Reg. 34830, June 18, 2014.

[17] Ibid. p. 34877.

Institute (EPRI).[18] Those guidelines are based on the best practices used in the industry for improving and maintaining energy efficiency.

Maui Electric's four boilers and Hawai'i Electric Light's two boilers underwent energy assessments and tune-ups in 2014 that were required by 40 CFR Part 63 Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources. The assessments, performed by a certified independent combustion engineer, concluded that the overall condition of the boilers is good and that good efficiency practices are followed. All the Maui Electric and Hawai'i Electric Light boilers are tested annually to confirm their efficiency and tune-ups are required under Subpart JJJJJJ once every five years.

Hawaiian Electric's boilers compare favorably for energy efficiency with other oil-fired EGUs in the U.S. The Energy Information Administration (EIA) collects and publishes Heat Rate data for several categories of EGUs. For the 2009 to 2013 period, EIA reported that the average HR for petroleum-fired EGUs was 10.9 MBtu/MWh.[19] By comparison, Hawaiian Electric's fourteen boilers on O'ahu averaged lower than 10.6 MBtu/MWh Heat Rate in the first 6 months of 2015. That is very good performance given the Hawaiian Electric boilers' operating rates.

Traditional style power plants were designed to operate near full capacity, often termed base-loaded, where they are most efficient. Operating them at lower and varying loads reduces their efficiency. Hawaiian Electric's boilers operate below full capacity. During 2012 through 2014, for instance, their average operating load was less than 60% of online capacity. There are two reasons for the lower load. One is that, unlike utilities on the mainland, Hawaiian Electric operates an isolated system. It cannot draw power from neighboring utilities in the event of system upsets so it must be entirely self-sufficient. To protect against power outages, Hawaiian Electric keeps enough unused generation capacity online as spinning reserve to absorb unexpected loss of the largest generation facility that is operating at any time.

Another factor that keeps operating load lower than ideal is imposed by the increasing amount of renewable energy that has been integrated into Hawaiian Electric's system. The output for renewable energy sources such as solar and wind is variable and intermittent because clouds reduce solar panel output and variable wind speeds reduce windmill output. Consequently, Hawaiian Electric's boilers must vary their operation in order to match overall system output with demand. The result of those constraints on operating load is that Hawaiian Electric's boilers typically operate below their peak efficiencies. Despite these constraints, as noted above, their HRs are competitive with those of mainland utilities, which generally do not have the same constraints.

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[18] *Heat Rate Improvement Guidelines.* EPRI, Palo Alto, CA: 2012. Publication 1023913.

[19] *Electric Power Annual.* U.S. EIA. March 23, 2015 release, Table 8.1.

Combustion Turbines

Combustion Turbines (CT) represent the Hawaiian Electric Companies' second-largest source of power generation. The Company operates three CTs on O'ahu, four on Maui, and five on Hawai'i Island.

The energy efficiency of CTs is highest when they operate in combined cycle mode rather than simple cycle. In simple cycle, the hot gases from the turbine are exhausted to the atmosphere, whereas in combined cycle hot exhaust gases pass through a heat recovery steam generator, where steam passes through a turbine to generate additional power.

All four of Maui's and two of Hawai'i Island's CTs are capable of operating in combined cycle mode. No other significant energy efficiency improvements have been identified.

The remaining three CTs on Hawai'i Island and three on O'ahu are simple cycle units. Although their energy efficiency could be improved by converting them to combined cycle, the Companies evaluated doing so and concluded that it would not be feasible given the function that the simple cycle CTs serve on the current system. These units operate less than 10 percent of the time and instead are used to provide fast response power in case of shortages on the system. Unlike boilers, which take a long time to start up, simple-cycle CTs can be started up quickly when needed. In contrast, it takes significantly longer to bring a combined-cycle CT fully online. Operating the current simple-cycle CTs in combined-cycle mode would defeat much of the reason they are used. Hawaiian Electric has not identified any energy efficiency improvements for its CTs that fit within the current design of its system. That does not rule out system design changes that could accommodate combined cycle combustion turbines; however, such changes could not be implemented before 2020, the compliance date for Act 234 units.

Diesel Electric Generators

Diesel electric generators (DEGs) have generally lower power output capability than boilers or combustion turbines and are mainly used to serve lower loads, typically in remote locations. DEGs also have the advantage that they can be brought online and ramped up quickly.

The Hawaiian Electric Companies operate DEGs that range in size from 1 MW to 12.5 MW each.

Hawaiian Electric received the following information from Valley Power Systems Northwest. Valley Power has supplied diesel generation equipment to the Hawaiian Electric Companies and is familiar with their DEGs.[20] Diesel electric generators are generally very efficient in converting fuel energy into electric power. There are few options available for improving their energy efficiency. One option is to install a turbocharger if a unit is not already equipped with one. However, all the DEGs covered by the Companies GHG Partnership already are equipped with

[20] Verbal communication between Dave Peterson of Valley Power Systems Northwest and Greg Narum of Hawaiian Electric, March 20, 2015.

turbochargers. Another option is to upgrade from 2-pass to 4-pass after-coolers, which can improve efficiency 1-3%. However, this may not be practical for Hawaiian Electric Companies' units because of their age and design. The benefit in terms of GHG emissions reduction would be small in any case, amounting to about 120 metric tons per year of CO2e for a 2% efficiency improvement of a 1 MW generator.

An approach that would more substantially reduce GHG emissions would be to replace the existing diesel engine generators with newer, more efficient models. Hawaiian Electric estimates that heat rates could be improved 10% to 20%, depending on the unit, by replacing the Companies' larger DEGs with new units similar to those constructed at the Schofield Generating Station.[21] According to data Hawaiian Electric submitted to the Public Utilities Commission, the 2015 installed cost for new DEG capacity up to 100MW is $2970/KWh.[22] Assuming a 15% heat rate improvement averaged over all the units, the fuel cost savings would be about $280 per year per KW of capacity based on estimated 2015 fuel costs[23] and 8500 hours per year of operation. Therefore, it would require about 10 years for the energy savings to pay back the investment cost. That cost can only be justified if the existing unit is nearing the end of its useful life.

Summary of Potential Energy Efficiency Improvements

The Hawaiian Electric Companies operate their power generating units at energy efficiencies that are equivalent to or better than mainland averages for oil-fired generators despite constraints imposed by their isolated location. The Company has researched additional opportunities for improving efficiency beyond steps already taken but has not identified any that are operationally and economically justified given current system designs and needs.

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[21] Email from Robert Isler of Hawaiian Electric Generation Planning Department. June 22, 2015.

[22] *Hawaiian Electric Power Supply Improvement Plan.* Table F-11. Docket 2011-0206. August 2014.

[23] Ibid, Table F-5.

Attachment F – Puna Geothermal Venture Equivalent GHG Emissions

The equivalent GHG emissions reduction from PGV's energy generation was calculated by comparing the combined actual emissions from Hawai'i Electric Light and HEP in 2017, the last full year PGV operated, with the 12 months from July 2018 to June 2019 when PGV was offline. The difference, 185,404 tons, was distributed among the generating facilities in proportion to their July 2018 to June 2019 operation. The result is tabulated in Table A-2.

The derivation of PGV's equivalent GHG emissions is summarized below.

Hawai'i Island Fossil Fuel GHG Emissions

Source	GHG Emissions, tons	
	PGV Online 2017	PGV Offline July 2018-June 2019
HELCO		
Keahole	193,103	260,090
Kaneolehua-Hill	243,346	180,345
Puna	26,400	67,806
HEP	98,962	238,974
HELCO-HEP Total	561,811	747,215
GHG Adjustment for PGV		**185,404**

Revised Form S-6
Campbell Industrial Park Generating Station
CSP No. 0548-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. CIP1 is a Siemens Westinghouse Power Corporation SGT6-3000E (135 MW nominal) combustion turbine.
2. Fuel type. CIP1 is currently permitted to burn naphtha, fuel oil No. 2, biodiesel (B100 and B99), and blends of fuel oil No. 2 and biodiesel (B100 and B99) with a maximum sulfur content of 0.05% by weight.
3. Fuel use. CIP1 has a maximum hourly fuel consumption rate of 1,482.6 MMBtu/hr.
4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change CIP1's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   NO_x emissions are controlled by water injection. SO_2 emissions are controlled by limiting the biodiesel fuel sulfur content to 50 ppm. Emissions of PM, PM_{10}, $PM_{2.5}$, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of any hazardous air pollutants are controlled by the use of No. 2 diesel or biodiesel and combustion system design.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when a unit must be run continuously for extended periods of time. Thus, this application does not include any daily, weekly, or monthly operating limits.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Refer to I.C.1 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Hawaiian Electric requests incorporation of the Greenhouse Gas emissions limitations into the Covered Source Permit CSP No. 0548-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan (GHG ERP) submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in <u>the Instructions for Applying for an Air Pollution Control Permit.</u>

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. **The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.**

IX. **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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.**

X. **The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**

XI. **Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

Revised Form S-6
Kahe Generating Station
CSP No. 0240-01-C
July 2019

File No.: _______

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - Fuel oil No. 6 with maximum sulfur content of 0.5% by weight for Units K-1 through K6.
   - Fuel oil No. 2 with maximum sulfur content 0.5% by weight for Units A and B.
   - A maximum of 115,000 gal/yr of specification (spec) used oil for Units K-1 through K-4.
   - Propane as igniter fuel for K-1 and K-2.
   - Fuel oil No. 2 with maximum sulfur content of 0.5% by weight as igniter fuel for K-3 through K-6.
   - Fuel oil No. 2 (diesel) with maximum 0.5% by weight sulfur as an alternate fuel for Boilers K-1 through K-6 as approved by the DOH on June 7, 2013.
   - Natural gas as alternate fuel for boilers K-1 through K-6 as approved by DOH on January 5, 2015.
3. Fuel use. Refer to the table below.

Maximum Design Fuel Use per Unit

Unit ID	Nominal Capacity	Heat Input (MMBtu/hr)	Ignition Fuel
K-1	92 MW	903	Propane
K-2	90 MW	900	Propane
K-3	92 MW	892	Diesel
K-4	93 MW	918	Diesel
K-5	142 MW	1,468	Diesel
K-6	142 MW	1,516	Diesel
A	2.5 MW	30.5	Diesel
B	2.5 MW	30.5	Diesel

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Kahe equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Sulfur emissions are controlled by limiting the fuel sulfur content to 0.5 percent by weight. Emissions of NO_x, PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of other HAP's are controlled by the use of No. 2 and No. 6 fuel oil and combustion system design. Unit 6 is equipped with low NO_x burners to control NO_x emissions.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. Depending on future power dispatch requirements, specific boilers may cycle off-line daily, or operate at reduced loads. However, there may be times when a unit must be run continuously for extended periods of time. Thus, this application does not include any annual operating limits for Units K-1 through K-5. Unit K-6 is limited to a daily average fuel consumption of 8,610 gal/hr. Units A and B are limited to a combined annual operating hour limit of 300 hours.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Refer to I.C.1 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Hawaiian Electric requests incorporation of the Greenhouse Gas emissions limitations into the Covered Source Permit CSP No. 0240-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan (GHG ERP) submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not Applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Revised Form S-6
Waiau Generating Station
CSP No. 0239-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - Fuel oil No. 6 with a maximum sulfur content of 0.5% by weight for Units 3 through 8.
   - Natural gas with maximum sulfur content of 175 grains per 100 SCF for Units 5 through 8.
   - Specification used oil for Units 3 through 8 (no more than 50,000 gallons per any rolling 12-month period).
   - Fuel oil No. 2 with a maximum sulfur content of 0.5% by weight for Units 9 and 10.
3. Fuel use. Refer to the table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Rate (MMBtu/hr)	Ignition Fuel
3	Babcock and Wilcox		RB-43	49 MW	576	Propane
4	Babcock and Wilcox		RB-92	49 MW	585	Propane
5	Babcock and Wilcox		RB-324	57 MW	633	Propane
6	Babcock and Wilcox		RB-328	58 MW	637	Propane
7	Combustion Engineering		20694	92 MW	923	Diesel
8	Combustion Engineering		20177	92 MW	922	Diesel
9	General Electric	MS7000	217725	50	682	Diesel
10	General Electric	MS7000	217724	52	691	Diesel

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Waiau equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the generating station as described below:

a. Unit operation during startup, shutdown, maintenance and testing of the combustion turbine generators and boilers. Boiler startup operations may range up to 7 hours and occur almost daily.

b. Alternate fuels. Hawaiian Electric may use alternate fuels and fuel additives with prior approval from the Department of Health.

c. Soot blowing is a necessary maintenance operation and may result in a temporary increase in opacity.

d. Use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit. In the event that the projected down time of the unit increases the likelihood of an interruption in electrical service, the down unit may be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's permitted emission limits.

e. Operate the combustion turbines, W9 and W10, below minimum load to address system disturbances and frequency issues. This request was submitted in a minor modification application dated May 6, 2015.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Sulfur emissions are controlled by limiting the fuel sulfur content to a maximum of 0.5% by weight. Emissions of NO_x, PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of any hazardous air pollutants are controlled by the use of fuel oil Nos. 6 and 2 and good combustion design.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. Depending on future dispatch requirements, the plant may cycle off line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Refer to I.C.1 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Hawaiian Electric requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0239-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Revised Form S-6
Honolulu Generating Station
CSP No. 0238-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Units 8 and 9 are Babcock & Wilcox boilers with steam turbines. See response to I.A.3 for additional information.
2. Fuel type. No. 6 and No. 2 fuel oil with 0.5% (max) by weight sulfur content for Units 8 and 9. The boilers also burn small quantities of spec used oil (less than 15,000 gal/yr).
3. Fuel use. Refer to the table below.

Maximum Design Fuel Use per Unit

Unit ID	Nominal Capacity	Fuel Rate	Ignition Fuel
Unit 8	56 MW	589.0 MMBtu/hr	Propane
Unit 9	57 MW	631.5 MMBtu/hr	Propane

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Honolulu equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation through combustion of fossil fuels (SICC 4911) is the only product or process.

The alternative scenario is the ability to switch fuels. Should cheaper fuels become available, or the supply of No. 2 or No. 6 fuel becomes limited, Hawaiian Electric may propose an alternate scenario that would allow the fuel switch, provided that all permit conditions are met.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Sulfur emissions are controlled by limiting the fuel sulfur content to 0.5 percent by weight. Emissions of NO_x, PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of any hazardous pollutants are controlled by the use of No. 2 and No. 6 fuel oils and combustion system design.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. The planned operation of Units 8 and 9 is 24 hours per day 7 days a week. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. Unit 8 and 9 are currently deactivated.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Unit 8 and 9 are currently deactivated.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Hawaiian Electric requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0238-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Revised Form S-6
Kanoelehua-Hill Generating Station
CSP No. 0234-01-C
July 2019

File No.: _______

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.

   - Hill 5 and 6 utilize fuel oils No. 6 and No. 2.
   - Hill 5 uses propane as an ignition fuel.
   - CT-1 utilizes fuel oil No. 2 with a maximum sulfur content of 0.4 percent by weight.
   - D-11, D-15, D-16, and D-17 utilize fuel oil No. 2 with a maximum sulfur content of 0.0015 percent by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.
   - Hill 5 and Hill 6 may consume up to 36,500 gal/rolling 12-month period of specification used oil. On November 22, 2017, the DOH approved consumption of specification used oil from Hawaii Petroleum.
   - Hawai'i Electric Light requested the addition of biodiesel and biodiesel/diesel blends in D-11, D-15, D-16, and D-17 in a permit renewal application dated August 31, 2012.

3. Fuel use. Refer to the table below.

Maximum Design Fuel Use per Unit

ID	Capacity (Nominal)	Fuel Flow (MMBtu/hr)	Ignition Fuel
Hill 5	14 MW	197	Diesel/ Propane
Hill 6	23 MW	249	Diesel
CT-1	11.6 MW	177.2	Diesel
D-11	2.0 MW	20.2	Diesel
D-15	2.5 MW	29.1	Diesel
D-16	2.5 MW	29.1	Diesel
D-17	2.5 MW	29.1	Diesel

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Kanoelehua-Hill equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the plant. The first includes the use of permanent and temporary replacement units in the event of a failure or major overhaul of an installed unit. In the event that the projected downtime of the installed unit increases the likelihood of an interruption in electrical service, the installed unit would be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's emission limits.

The second alternative operating scenario is unit operation during start-up, shutdown, maintenance and testing. Boiler startup operations may range up to 7 hours. Maintenance activities include soot blowing. The time period of this maintenance operation will not exceed 1.5-hours in duration two times per day. These maintenance activities are required to maximize generation efficiency and minimizing fuel usage.

A third alternate scenario is the ability to switch fuels. Should cheaper fuels become available, or the supply of normal fuel become limited, Hawai'i Electric Light proposes an alternate scenario that would allow the fuel switch provided that all permit conditions are met.

A fourth alternative scenario occurs during emergency load conditions. Certain equipment malfunctions (such as sudden loss of a unit) may necessitate the operation of Hill 5 and 6, CT-1 and D-11, D-15, D-16, and D-17, at loads as high as 110% of peak load. The time period of this operation will be limited to no more than 30 minutes in duration. This operation will not result in a 3-hr average emission rate that exceeds the maximum emission limits proposed in this application.

A fifth alternative involves the use of fuel additives to reduce corrosion, control biological growth, and enhance combustion, etc. Emissions during this scenario will not affect emission estimates.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Sulfur emissions are controlled by limiting the fuel sulfur content to 0.4% by weight for CT-1, 0.0015% for the diesels, and 2% for the boilers. Emissions of PM_{10}, CO, and VOC are controlled by combustion design. CO emissions from D-11, D-15, D-16, and D-17 are controlled by the Diesel Oxidation Catalyst (DOC). The DOC will reduce CO emissions by at least 70 percent or limit CO emissions to 23 ppmvd at 15 percent O_2. Emissions of any hazardous pollutants are controlled by the use of No. 2 diesel oil for CT-1, D-11, D-15, D-16, and D-17 and No. 6 fuel oil used for the boilers and combustion system design for all units.

   Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. The planned operation of each unit is 24 hours per day, 365 days per year. Depending on future dispatch requirements, some units may cycle off-line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Operation is not seasonal or irregular.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

With this application, Hawai'i Electric Light requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0234-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not Applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Does not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. <u>Does not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.</u>

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in <u>the Instructions for Applying for an Air Pollution Control Permit.</u>

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Revised Form S-6
Keahole Generating Station
CSP No. 0007-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - No. 2 diesel fuel with 0.4 percent by weight maximum sulfur content for units CT-4, CT-5, and BS-1.
   - Starting May 3, 2013, No. 2 diesel with 0.0015 percent by weight sulfur content, minimum Cetane index of 40 or maximum aromatic content of 35% volume, for units D-21, D-22, and D-23.
   - Biodiesel (B100) and biodiesel/diesel blends with up to 1% diesel (B99) as alternate fuels for CT-4 and CT-5 were approved by the DOH on December 16, 2013.
3. Fuel use. Refer to the table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Flow Rate
D-21	General Motors	20-645F4B	74-B1-1078	2.5 MW	28.1 MMBtu/hr
D-22	General Motors	20-645F4B	66-K1-1062	2.5 MW	28.1 MMBtu/hr
D-23	General Motors	20-645E4	69-H1-1057	2.5 MW	28.1 MMBtu/hr
BS-1	Caterpillar	3412	81Z07275	500 kW	5.57 MMBtu/hr
CT-4	General Electric	LM2500	481-688	20 MW	275 MMBtu/hr
CT-5	General Electric	LM2500	481-692	20 MW	275 MMBtu/hr
ST-7				16 MW	NA
CT-2	Jupiter	GT-35	JF88702	18 MW	198 MMBtu/hr

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Keahole equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the generating station as described below:

a. Use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit. In the event that the projected down time of the unit increases the likelihood of an interruption in electrical service, the down unit would be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's permitted emission limits.

b. CT-4 and CT-5 may operate below 25% of peak load during testing of the heat recovery steam generators and steam turbine and steam blows needed to clean the steam tubes prior to initial operation.

c. Should less expensive fuels become available, or the supply of No. 2 diesel become limited, Hawai'i Electric Light may use alternative fuels with prior approval from the Department of Health.

d. In the event of emergency load conditions such as the sudden loss of a unit, CT-2, CT-4 and CT-5 may operate up to 110 percent of peak load for up to 30 minutes. Such operation will not exceed the permitted 3-hour average emission rates.

e. Fuel additives to reduce corrosion, control biological growth, and enhance combustion may be used in CT-4 and CT-5.

f. Hawai'i Electric Light, with the approval from the Department of Health, may use alternate means and methods to improve combustion and/or reduce emissions for CT-4 and CT-5.

g. Hawai'i Electric Light requested to operate the combustion turbine generators, CT-2, CT-4 and CT-5, below minimum load with water injection to address system disturbances and frequency issues in a minor modification application dated 12/10/2015.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Fuel injection timing retard (FITR) is used on D-21, D-22, and D-23 to control NO_X emissions. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.0015 percent of less. When CT-4 and CT-5 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. SO_2 emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for CT-4, CT-5, and BS-1 and 0.0015 percent by weight for D-21, D-22, and D-23. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. CO emissions for D-21, D-22, and D-23 will be controlled by a DOC. The DOC will reduce CO emissions by at least 70 percent or limit CO to 23 ppmvd at 15% O_2. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design. Refer to Attachment S-1d for emission rate calculations.

Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.
   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. The planned operation of units D-22, D-23, CT-4, and CT-5 is up to 24 hours per day, seven days per week. Units BS-1 and unit D-21 are operated as needed. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) for CT-2.
2. Total hours per year. Units D-22, D-23, CT-4, and CT-5 will operate 8760 hours per year. Fuel consumption is limited on a rolling 12-month basis to 70,000 gallons in D-21. Operation of BS-1 is limited to 300 hours on a rolling 12-month basis. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) for CT-2.
3. If operation is seasonal or irregular, describe. Refer to D.1 and 2 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Hawai'i Electric Light requests incorporation of the Greenhouse Gas Emissions Limitations into the Keahole Covered Source Permit CSP No. 0007-01-C consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. <u>Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.</u>

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. <u>Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.</u>

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in <u>the Instructions for Applying for an Air Pollution Control Permit.</u>

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Revised Form S-6
Puna Generating Station
CSP No. 0235-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type. CT-3 and PBSG1 burn No. 2 diesel fuel with a 0.4% maximum sulfur content. The boiler burns No. 2 and No. 6 fuel oil with a 2.0% maximum sulfur content. In addition the boiler burns a maximum of 200,000 gal/yr of specification used oil. On November 22, 2017, the DOH approved consumption of specification used oil from Hawaii Petroleum.
3. Fuel use. Refer to the table below.

Maximum Design Fuel Use per Unit

Unit ID	Nominal Capacity	Heat Input (MMBtu/hr)
Boiler	15.5 MW	249
CT-3	20 MW	275
PBSG1	600 kW	6.34

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Puna's equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the plant. The first includes the use of a temporary replacement unit in the event of a failure or major overhaul of CT-3 or the boiler. In the event that the projected downtime increases the likelihood of an interruption in electrical service, CT-3 or the boiler would be temporarily replaced. Emissions from the replacement unit will comply with the original unit's operating restrictions and emission limits.

The second alternative operating scenario is unit operation during start-up, shut-down, maintenance, and testing of all units. Boiler start-up operations may range up to 8 hours. Maintenance activities include soot blowing. The time period of this maintenance operation will not exceed 1-hour in duration two times per day. These maintenance activities are required to maximize generation efficiency and minimize fuel usage.

A third alternate scenario is the ability to switch fuels. Should cheaper fuels become available, or the supply of No. 2 or No. 6 fuel oil becomes limited, Hawai'i Electric Light proposes an alternate scenario that would allow the fuel switch provided that all emission limits and regulatory requirements are met.

A fourth alternative scenario occurs during emergency load conditions. Certain equipment malfunctions (such as sudden loss of a unit) may necessitate the operation of CT-3 at loads as high as 110% of peak load. The time period of this operation will be limited to no more than 30 minutes in duration. This operation will not result in a 3-hr average emission rate that exceeds the maximum emission limits.

A fifth alternative scenario occurs during unpredictable periods of equipment failure, upsets, or emergency conditions. During any emergency condition, Hawai'i Electric Light will operate the subject equipment in such a manner as to minimize emissions. Hawai'i Electric Light will comply with the Emergency Provisions (§11-60.1-16.5).

A sixth alternative scenario involves the burning of a maximum total of 200,000 gal/yr, 90 gal/hr, of specification (spec) used oil. The spec used oil consists of collected used oil, such as waste oil, lubricating oil, and waste diesel oil, crankcase oil, transformer oil (dielectric fluid), solvents and kerosene obtained from the equipment operating at the Hawai'i Electric Light facilities.

A seventh alternative scenario involves the use of fuel additives to reduce corrosion, control biological growth, enhance combustion, or other reasons. Additives used during this scenario shall not affect emission estimates.

Hawai'i Electric Light requested to operate the CT-3 below minimum load to address system disturbances and frequency issues in a minor modification application dated October 16, 2015.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Water injection is used on CT-3 to reduce NO_X emissions to 42 ppmv at 15 percent O_2, dry with a fuel-bound nitrogen content of 0.015 percent or less. Fuel sulfur content is limited to 0.4 percent by weight for CT-3 and PBSG1 and 2.0% by weight for the boiler. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of any hazardous air pollutants are controlled by the use of No. 2 fuel oil for CT-3 and PBSG1, by the use of No. 6 fuel oil for the boiler, and combustion system design. Compliance monitoring devices and activities are discussed in form C-2.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. Depending on future power dispatch requirements, some units may cycle off-line daily, or operate at reduced loads. However, there may be times when a unit must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits. Units PBSG1 is limited to an annual operating hour limit of 300 hours.
2. Total hours per year. Up to 8,760 hours per year each for CT-3 and the boiler. Units PBSG1 is limited to an annual operating hour limit of 300 hours.
3. If operation is seasonal or irregular, describe. Refer to I.C.1 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

With this application, Hawai'i Electric Light requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0235-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in <u>the Instructions for Applying for an Air Pollution Control Permit.</u>

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. **The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.**

IX. **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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.**

X. **The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**

XI. **Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

Revised Form S-6
Kahului Generating Station
CSP No. 0232-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. **In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:**

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - No. 6 fuel oil with 2.0% (max) by weight sulfur content, and in emergencies, No. 2 fuel oil with 0.5% (max) sulfur by weight.
   - No more than 300,000 gal/yr of specification (spec) used oil. On December 13, 2017, the DOH approved consumption of specification used oil from Maui Petroleum.
3. Fuel use. Refer to the table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Flow Rate	Ignition Fuel
K-1	Combustion Engineering	None	13413	5.0 MW	94.0 MMBtu/hr	Electric
K-2	Combustion Engineering	None	15345	5.0 MW	94.0 MMBtu/hr	Propane
K-3	Combustion Engineering	None	17343	11.5 MW	172.0 MMBtu/hr	Propane
K-4	Babcock & Wilcox	None	PFI3030	12.5 MW	181.0 MMBtu/hr	Propane

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Kahului equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the plant. The first alternative operating scenario is unit operation during start-up, shut-down, maintenance, and testing. Boiler start-up operations may occur up to 225 times per year per boiler and occasionally range up to 6 hours.

A second alternate scenario is the ability to switch fuels. Should cheaper fuels become available or the supply of No. 6 fuel oil become limited, MECO may propose an alternate scenario that would allow the fuel switch, provided that all emission limits and regulatory requirements of the DOH rules are met.

A third alternative scenario involves boiler soot-blowing. This is a necessary maintenance operation and may result in a temporary increase in opacity.

A fourth alternative scenario is the use of fuel additives and other products which may be used to control algae, inhibit corrosion, enhance combustion, etc. Emissions during this scenario will comply with all permit conditions.

No additional changes to operating scenarios are proposed with this application

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Sulfur emissions are controlled by limiting the fuel sulfur content to 2 percent for No. 6 fuel oil and 0.5 percent for No. 2 fuel oil. Emissions of NO_x, PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of any hazardous air pollutants are controlled by the use of No. 6 fuel oil or No. 2 fuel oil and combustion system design.

   Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. The planned operation of units K-1 through K-4 is 24 hours per day, seven days per week. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time.
2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Operation is not seasonal or irregular.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

With this application, Maui Electric requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0232-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. **An application shall be determined to be complete only when all of the following have been complied with:**

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. **The Director shall not continue to act upon or consider an incomplete application.**

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. **After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. **The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.**

IX. **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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.**

X. **The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**

XI. **Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

Revised Form S-6
Maalaea Generating Station
CSP No. 0067-01-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. **In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:**

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - Fuel oil No. 2 diesel with 0.4% maximum sulfur content and biodiesel.
   - Spec used oil (not to exceed 150,000 gal/yr).
   - Fuel oil No. 2 with a maximum sulfur content of 0.0015 percent by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.
3. Fuel use. Refer to the table below.

Maximum Design Fuel Use per Unit

Unit ID	Make	Model Number	Unit Type	Nominal Output	Nominal Heat Input
M1-M3	General Motors	20-645E4	Diesel Engine	2.5 MW	29.2 MMBtu/hr
M4 & M6	Cooper Bessemer	LSV-20-T	Diesel Engine	5.6 MW	58.8 MMBtu/hr
M5 & M7	Cooper Bessemer	LSV-20-T	Diesel Engine	5.6 MW	58.8 MMBtu/hr
M8-M9	Colt Industries	C-P PC2V	Diesel Engine	5.6 MW	60.2 MMBtu/hr
M10-M13	Mitsubishi Hvy. Ind.	185V52/55A	Diesel Engine	12.5 MW	122.7 MMBtu/hr
X1-X2	General Motors	20-645E4	Diesel Engine	2.5 MW	28.5 MMBtu/hr
SG1	General Motors / Detroit	12V92TAB/8 123-7416	Diesel Engine	600 kW	6.34 MMBtu/hr
M14 & M16	General Electric	LM2500	Combustion Turbine	20 MW	275 MMBtu/hr
M17 & M19	General Electric	LM2500	Combustion Turbine	20 MW	275 MMBtu/hr

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Maalaea equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation (SIC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the plant. The first alternative operating scenario is the ability to conduct steam blows activity.

The second alternative operating scenario includes the use of a temporary replacement unit for the diesel engine generators and combustion turbines, in the event of a failure or major overhaul of an installed unit. In the event that the projected down-time of the installed unit increases the likelihood of an interruption in electrical service, the installed unit would be temporarily replaced. Emissions from the temporary replacement unit will comply with the original unit's emission and operating limits.

A third alternative scenario is the ability to operate below the 25% load for maintenance and testing, provided that all emission limits and regulatory requirements of the DOH rules are met.

A fourth alternative scenario is the ability to burn alternative fuels. Should cheaper fuels become available or the supply of No. 6 fuel oil become limited, Maui Electric proposes an alternate scenario that would allow the fuel switch, provided that all emission limits and regulatory requirements of the DOH rules are met.

A fifth alternative operating scenario is the use of fuel additives and other products which may be used to control algae, inhibit corrosion, enhance combustion, etc. Emissions during this scenario will comply with all permit conditions.

A sixth alternative operating scenario is the ability to operate the combustion turbines up to 110% above peak load if equipment malfunction such as a sudden loss of a unit occurs, provided conditions specified in CSP No. 0067-01-C are met.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Fuel Injection Timing Retard (FITR) is used on diesel engine generating units M12, M13, X1, and X2 to control NOx emissions. Water injection is used on M14, M16, M17, and M19 to limit NOx emissions to 42 ppmvd at 15 percent O_2, dry with a fuel-bound nitrogen content of 0.015 percent by weight or less. Sulfur emissions are controlled by limiting the fuel sulfur content to 0.4 percent for units M4 through M13, M14, M16, M17, and M19 and 0.0015% for units M1 through M3, X1, and X2. CO emissions from units M1 through M13, X1, and X2 are controlled by the Diesel Oxidation Catalyst (DOC). The DOC will reduce CO emissions by at least 70 percent or limit CO emissions to 23 ppmvd or less at 15 percent O_2. Emissions of PM, PM10, CO and VOC are controlled by combustion design and good combustion practices. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

   Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month. The planned operation is full load the majority of the time. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time.
2. Total hours per year. Up to 8,760 hours per year. Units X1 and X2 are limited by PSD Permit HI 86-02 to 4,380 hours per year, per unit. Unit SG1 is limited by PSD Permit HI 90-02 to 300 hours per year.
3. If operation is seasonal or irregular, describe. Operation is not seasonal or irregular.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

See item I.B.1. above for current work practices that affect emissions of any regulated or hazardous air pollutant.

Maui Electric requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0067-01-C, consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. **After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. **The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.**

IX. **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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.**

X. **The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**

XI. **Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

Revised Form S-6
Palaau Generating Station
CSP No. 0031-04-C
July 2019

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:

1. Maximum design capacity. Refer to the table below.
2. Fuel type.
   - No. 2 fuel oil with maximum sulfur content of 0.4 percent by weight for CT1.
   - No. 2 diesel with maximum 0.0015 percent by weight sulfur content, minimum Cetane index of 40 or maximum aromatic content of 35% volume for Units CAT1 and CAT2, CUM3 through CUM6, CAT7 through CAT9.
   - Specification used oil for Units CUM3 through CUM6 and CAT7 through CAT9.
3. Fuel use.
   - The total combined fuel consumption of CUM3-CUM6 shall not exceed 1,650,000 gallons in any rolling twelve-month (12-month) period.
   - The total combined specification used oil consumption of CUM3-CUM6 and CAT7-CAT9 shall not exceed 10,000 gallons in any rolling twelve-month (12-month) period.
   - The total fuel consumption of CT1 shall not exceed 1,230,000 gallons in any rolling twelve-month (12-month) period.

Maximum Design Fuel Use per Unit

Unit ID	Make	Model Number	Unit Type	Nominal Rating (MW)	Nominal Heat Input (MMBtu/hr)	Fuel (gal/hr)
CUM3, CUM4, or CUM6	Cummins	KTA50	Diesel Engine	1.0	9.09	64.9
CUM5	Cummins	KTTA50	Diesel Engine	1.0	9.52	68.0
CAT7, CAT8, or CAT9	Caterpillar	3608	Diesel Engine	2.2	23.38	167.0
CAT1 or CAT2	Caterpillar	3516	Diesel Engine	1.25	12.62	90.63
CT1	Solar International	Centaur T4001	Combustion Turbine	2.0	34.0	240.0

4. Production capacity. Does not apply.
5. Production rates. Does not apply.
6. Raw materials. Does not apply.
7. Provide any manufacturer's literature. This application does not change any of Palaau equipment's manufacturer's specifications.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation through combustion of fossil fuels (SICC 4911) is the only product or process.

Several types of alternative operating scenarios apply to the plant. A first alternate scenario includes the use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit, provided the requirements in Attachment IIA Section C.7.a are met.

A second alternative scenario is the ability to switch fuels. Should cheaper fuels become available, Maui Electric may propose an alternate scenario that would allow the fuel switch, provided that all emission limits and regulatory requirements of the DOH rules are met.

No additional changes to operating scenarios are proposed with this application.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   NO_x emissions from Units CUM3 through CUM6, CAT1, and CAT2 are controlled by fuel injection timing retard (FITR). NO_x emissions from Units CAT7 through CAT9 are controlled by FITR and intake air cooling. Emissions of PM/PM_{10}, CO, and VOC are controlled by combustion design. SO_2 emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for Unit CT1 and 0.0015 percent by weight for units CUM3 through CUM6, CAT7 through CAT9, CAT1, and CAT2. CO emissions will be controlled by the DOC for units CUM3 through CUM6, CAT7 through CAT9, CAT1, and CAT2. The DOC will reduce CO emissions by at least 70 percent or limit CO to 23 ppmvd at 15% O_2. Emissions of any hazardous pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

2. List all ***new insignificant*** activities in accordance with §11-60.1-82.

   No additional changes/additions to insignificant activities are proposed with this application.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. 1. Total hours per day, per week, and/or per month. The planned operation of the facility is 24 hours per day, seven days per week. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While these expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits.

2. Total hours per year. Up to 8,760 hours per year.
3. If operation is seasonal or irregular, describe. Refer to I.C.1 above.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.
2. Explanation of all proposed exemptions from any applicable requirements. See Forms C-1 and C-2.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

Pollution controls include a fuel sulfur content limit, good combustion practices, and FITR.

Maui Electric requests incorporation of the Greenhouse Gas Emissions Limitations into the Covered Source Permit CSP No. 0031-04-C consistent with the Greenhouse Gas Emissions Reduction Plan submitted to the DOH on February 28, 2018, the subsequent updates submitted to the DOH on October 17, 2018 and May 15, 2019, and the latest update dated July 26, 2019, enclosed with this application.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable. Not applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96. No emissions trading is proposed.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards. Do not apply. The proposed modification will not increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7. Do not apply. The proposed modification is not subject to Subchapter 7 of HAR Chapter 11-60.1.

J. Provide the following for Compliance purposes:

1. A compliance plan, Form C-1.
2. A compliance certification, Form C-2.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. **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 the draft significant modification to the covered source in accordance with HAR §11-60.1-99.**

X. **The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**

XI. **Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

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JUL 30 2019

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

Attention: Ms. Marianne Rossio, P.E.
Manager, Clean Air Branch

Subject: Amendment to Application for Significant Modification of Covered Source Permit
Covered Source Permit No. 0087-02-C

Dear Ms. Rossio,

AES Hawaii, LLC submitted a Significant Permit Modification Application for Covered Source Permit No. 0087-02-C on March 28, 2018. The application incorporated the Greenhouse Gas (GHG) Emission Reduction Plan (ERP) dated February 28, 2018, which is a joint ERP between AES, Hawaiian Electric Companies (HECO), and other partnering facilities. On July 26, 2019, HECO resubmitted their ERP to DOH with proposed 2019 GHG limits for PGV outage, affecting the partnership total for 2019. This amendment requests a total partnership emission cap on CO2e emissions from AES, HECO and other partnering facilities of 7,208,661 short tons per year. Please note that all equipment, operations, and material throughput remain unchanged.

We appreciate your attention to this request. Please feel free to call Priya Kumar at 682-3409, or e-mail at priya.kumar@aes.com, with any questions that you may have.

Sincerely,

Steven Barnoski
Plant Manager
AES Hawaii, LLC

Cc:
Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9

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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

JULY 30, 2019

HAND DELIVERED
JUL 30 2019

AES
United States

AES HAWAII, LLC

GREENHOUSE GAS EMISSION REDUCTION PLAN

JULY 30, 2019

CONTENTS

TABLES

APPENDICES

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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C. GHG Control Evaluation Procedure Flow Chart

D. Detailed Cost Estimates

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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	Expected GHG Emission Rate 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:

$$\textit{Facility-Wide Baseline Emissions (tpy } CO_2e\textit{)} = \textit{Facility-Total Baseline GHG Emissions (tpy } CO_2e\textit{)} - \textit{Facility Baseline Biogenic } CO_2 \textit{ Emissions (tpy } CO_2\textit{)}$$

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.

[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

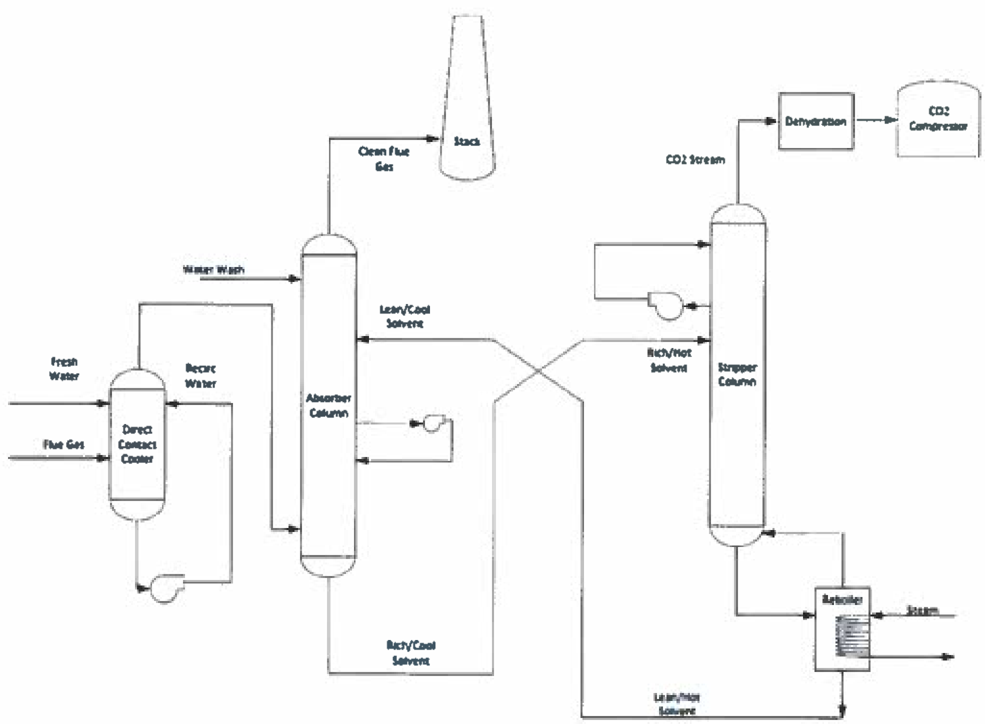
5.1.2 Step 2: Technical Feasibility of Potential GHG Control Options

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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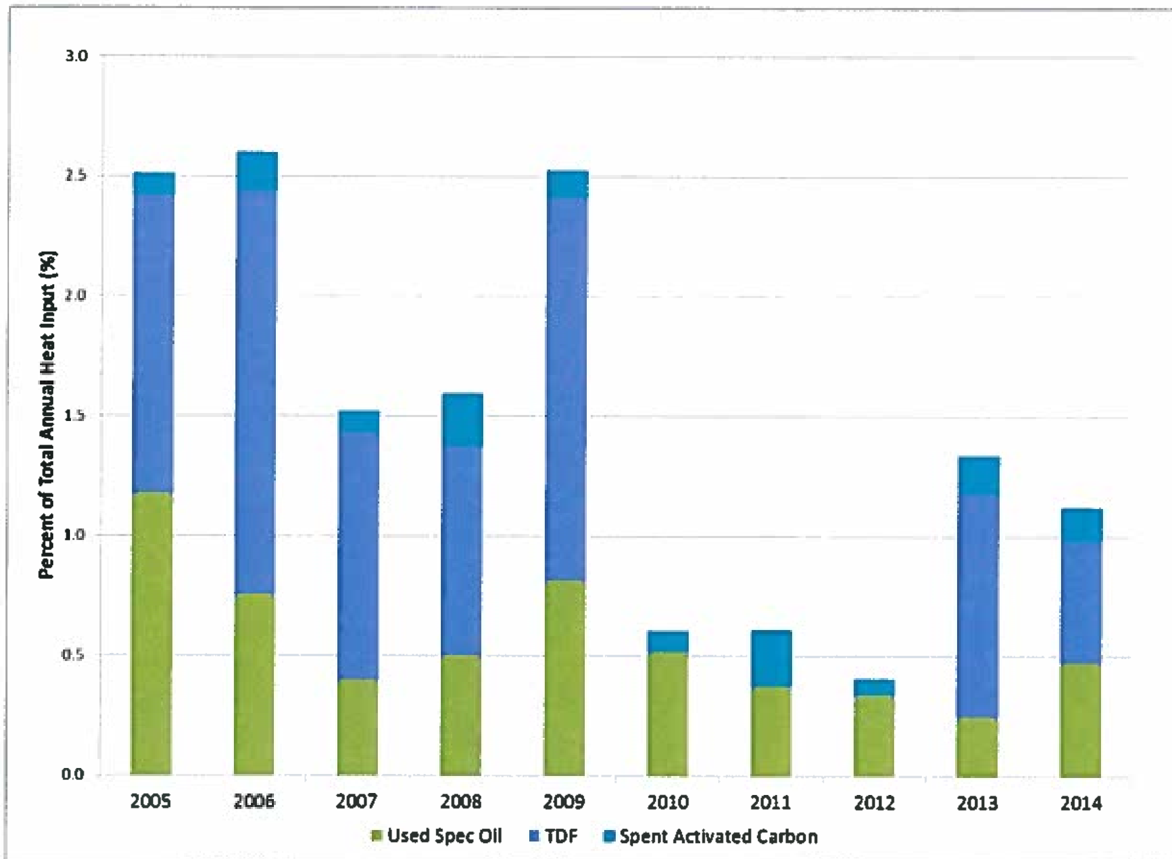
[8] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, 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.

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

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

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:

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

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.

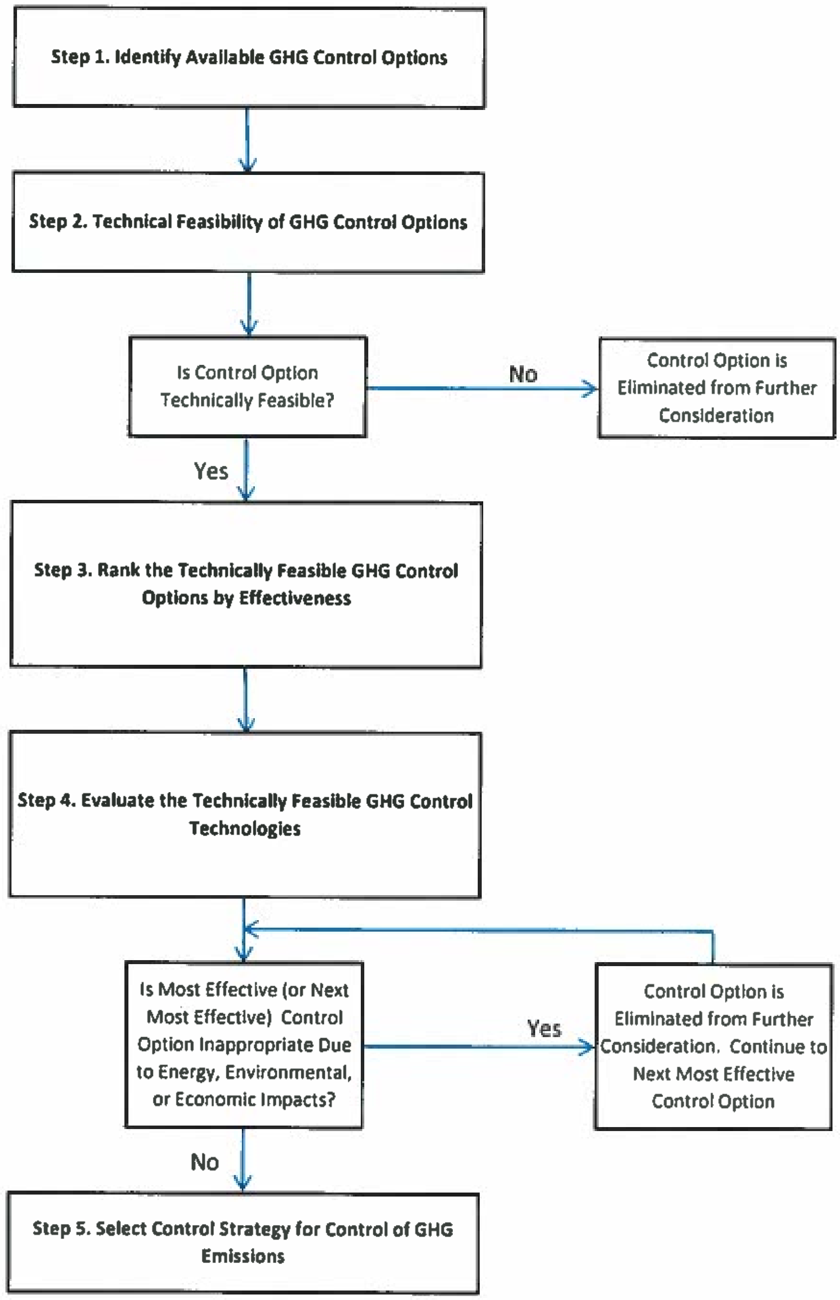
Note 7. Activated carbon usage is based on actual delivery volumes.

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 CO_2 Emissions (tpy)	1,681,605
Post HRI CO_2 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**	

GHG Cost Evaluation
Heat Rate Improvements

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	0.00	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**	

GHG Cost Evaluation
Heat Rate Improvements

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 $2.05/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	

GHG Cost Evaluation
Heat Rate Improvements

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 CO_2 Emissions (tpy)	1,681,605
Post HRI CO_2 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	0.00	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	

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	

GHG Cost Evaluation
Heat Rate Improvements

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 CO_2 Emissions (tpy)	1,681,605
Post HRI CO_2 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 $530/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 $34,500 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 $/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
	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 Fuel Oil Co-Firing CO_2 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
Case	2 x 100 MW-gross 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	

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

	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 Biomass Co-Firing CO2 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 $196.49/MT
Disposal Cost Differential	$4,010,000	Based on $37/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

		PGV 100% Operation	Calendar Year 2019 GHG Limits	
	Covered	CO2e Emissions Limit	GHG Limit Adjustment	CO_2e Emissions Limit
Company	Source	(tpy)	(tpy)	(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**

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MAR 28 2018

AES
we are the energy

March 28, 2018

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

Attention: Ms. Marianne Rossio, P.E.
Manager, Clean Air Branch

Subject: Application for Significant Modification of Covered Source Permit
Covered Source Permit No. 0087-02-C

Dear Ms. Rossio,

With this letter, AES Hawaii, Inc. is submitting a Significant Permit Modification Application for Covered Source Permit No. 0087-02-C. Enclosed please find a check in the amount of one thousand dollars ($1,000.00) for the significant modification fee.

We appreciate your attention to this request. Please feel free to call Priya Kumar at 682-3409, or e-mail at priya.kumar@aes.com, with any questions that you may have.

Sincerely,

Steven Barnoski
Plant Manager
AES Hawaii, Inc.

Cc:
Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9

Enclosures:
Air Permit Application (2)
Application Fee

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Covered Source Significant Modification Permit Application

CSP No. 0087-02-C

March 2018

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ERM

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1.0 INTRODUCTION

Environmental Resources Management (ERM), on behalf of AES Hawaii, Inc. (AES), is submitting this application for a significant modification to its Covered Source Permit (CSP) No. 0087-02-C for the 203 MW Coal- Fired Cogeneration plant located at 91-086 Kaomi Loop, Kapolei, Hawaii (Figure 1).

This Significant Modification application incorporates the Greenhouse Gas (GHG) Emission Reduction Plan (ERP) dated February 28, 2018, which is a joint ERP between AES, Hawaiian Electric Companies (HECO), and other partnering facilities. It is noted that all equipment, operations, and material throughput remain unchanged.

The facility is a major source since potential annual emissions for CO, NOx, PM, SO_2, and VOC exceed 100 tons per year and potential annual hazardous air pollutant (HAP) emissions exceed 10 tons for any one HAP (Lead and Hydrogen Chloride) and 25 tons for any combination of HAP. The facility is currently permitted by PSD No. HI 88-02 and CSP No. 0087-02-C.

2.0 REQUESTED CHANGES TO PERMIT

Though all equipment, process, fuel, and material throughput will remain unchanged, the following changes are proposed to the existing permit:

1) A total partnership emission cap on CO_2e emissions from AES, HECO and other partnering facilities of 6,982,040 short tons per year;
2) A facility-wide emission cap on CO_2e emissions from AES of 1,691,605 short tons per year;
3) A January 1, 2020 compliance date for the CO_2e emission cap pursuant to HAR § 11-60.1-204(c);
4) GHG emissions monitoring, recordkeeping, and reporting measures from the applicable sections of Title 40 Code of Federal Regulations (CFR), Part 98, Mandatory GHG Reporting, and HAR Title 11, Chapter 60.1, Air Pollution Control;
5) The GHG emissions reduction plan shall become a part of the CSP application process for renewals and any required modifications. With each subsequent GHG emission reduction plan submittal, the owner or operator of the affected source shall report:
    i. The GHG emission reduction status;
    ii. Factors contributing to the emission changes;
    iii. Any control measure updates; and
    iv. Any new development or changes that would affect the basis of the facility-wide CO_2e emissions cap.

In addition to the permit changes requested above, emissions calculations updates are described in Section 7.0.

3.0 MODIFICATION STATEMENT

The proposed application is a significant modification as it incorporates GHG monitoring, recordkeeping and reporting requirements into the permit.

4.0 FACILITY OVERVIEW

4.1 Equipment Listing

No equipment changes are proposed for the facility for this significant permit modification. The following equipment has been permitted in the CSP No. 0087-02-C and will remain in operation with no changes to throughput, operating schedules or capacity.

- Two Circulating Fluidized Bed (CFB) boilers of maximum capacity 2,150 MMBtu/hr each;
- Coal processing equipment that consists of the following:
  - The overland coal conveyor;
  - Two (2) coal lowering wells;
  - Four (4) coal conveyors;
  - Coal reclaim hopper;
  - 275 tons per hour electric coal crusher;
  - Four (4) coal storage silos;
  - Active storage pile;
  - Inactive storage pile;
  - Trucks;
  - Front-end loaders; and
  - One Mikro-Pulsaire baghouse for the coal crusher (model no. 64S-8-40 "C," serial no. 1CHD-DCO-1).
- Tire Derived Fuel (TDF) handling equipment including TDF stockpile, front end loader, a TDF hopper and two conveyors
- Limestone Processing Equipment: dryer, mikro pulverizer and baghouses (2 of each)
- Limestone storage and handling equipment that includes:
  - Active wetted storage piles,
  - Front end loaders,
  - One covered conveyor,
  - One storage hopper with a dust collector, and
  - Four (4) limestone feeders each fitted with a dust collector.
- A five-cell wet cooling tower;

- A 60,000 gallon fuel oil storage tank; and
- Ash handling equipment, all of which are fitted with bag filters or dust collectors:
    - Fly ash reinjection surge hopper;
    - Bed ash storage hopper;
    - Bed ash silo;
    - Fly ash silo;
    - Two mechanical separators;
    - One conditioned ash mixer; and
    - Trucks to transport bed ash, fly ash and conditioned ash offsite.

Equipment specification sheets are available in Appendix C.

4.1.1 Air Pollution Control Equipment and Activities

4.1.1.1 Fugitive Dust Suppression

Water spray is used as necessary to minimize fugitive PM emissions from the material stockpiles, trucks traveling on unpaved roads and trucks traveling on paved roads. Water suppression control efficiency is conservatively set at 50% to be consistent with the current CSP. Additional fugitive dust control measures employed include the use of covered conveyors and partial enclosures around lowering wells. Specific methods used throughout the facility are summarized in the Table 1 of Form C-2.

4.1.1.2 SNCR with Ammonia Injection

AES uses low temperature staged combustion and an SNCR system using ammonia injection (Thermal DeNOx manufactured by Alstom Power) to control NOx emissions by a minimum of 70%. The process breaks down the NOx into water and nitrogen. The optimum combustion temperatures for the efficient use of ammonia injection are 1,400 to 1,900 degrees Fahrenheit.

4.1.1.3 Limestone Injection

AES achieves 75% to 90% reduction in SO_2 emissions by injecting pulverized limestone into the combustion zone. The SO_2 is absorbed by the limestone and forms gypsum. The heavier particles drop to the hopper while the lighter particles are carried by the flue gas and captured by the boiler baghouses.

4.1.1.4 Baghouses

The facility uses the following baghouses to control TSP, PM_{10} and $PM_{2.5}$ emissions by a minimum of 99%.

Emission Source	Qty	Manufacturer	Model	Operating Pressure
Boilers	2	ABB	2 420S-10-50	1-9 in H_2O
Limestone dryers/pulverizers	2	Mikro-Pulsaire	H1/H2	1-7 in H_2O
Limestone storage hoppers*	1	Mikro-Pulsaire	100-S-8-20 "C"	1-7 in H_2O
Limestone feeders *	4	Aeropulse	SB-9-4-H-N	1-7 in H_2O
Coal crusher	1	Mikro-Pulsaire	64S-8-40 "C"	1-7 in H_2O
Coal storage silos and CC4*	1	Mikro-Pulsaire	100-S-8-20 "C"	1-7 in H_2O
Fly ash reinjection hopper*	1	Mikro-Pulsaire	25S-8-30 "B"	1-7 in H_2O
Bed ash storage hopper*	1	Mikro-Pulsaire	25S-8-30 "B"	1-7 in H_2O
Fly ash silo*	1	Mikro-Pulsaire	64S-8-20 TRH "B"	1-7 in H_2O
Bed ash silo*	1	Mikro-Pulsaire	64S-8-20 TRH "B"	1-7 in H_2O
Conditioned ash mixer*	1	Dalamatic Unimaster	DLMV20F	1-7 in H_2O

* These baghouses are considered insignificant due to the small estimated potential emissions.

4.1.1.5 Fuel Sulfur Content

Sulfur content is an indicator of SOx and PM emission; therefore, controlling the amount of sulfur in fuels controls potential emissions of SOx and PM.

The maximum sulfur content of fuel oil no. 2 and specification used oil is limited to 0.5 percent by weight.

4.1.1.6 Good Combustion Practices

Proper boiler operation and good combustion practices are employed to minimize uncontrolled PM, CO and VOC emissions.

4.2 Raw Material Specification

AES is a cogeneration plant producing electricity and steam using CFB boilers and turbine generator. The raw materials used in the process are listed below:

- The boilers' fuels (coal, TDF, spent activated carbon, biomass, fuel oil no. 2, and specification used oil) to generate electricity and steam;
- Fuel oil no.2 and specification used oil used to support combustion and limestone processing operations;
- Ammonia/urea for the SNCR system;
- Limestone for the limestone injection system; and
- Other materials used for support operations including, but not limited to, cooling tower chemicals and lubricating oils.

A complete process description is presented in Section 5.0.

4.3 Fuel Type and Usage

The two boilers primarily burn coal during normal operations in combination with biomass, TDF, spec used oil, and spent activated carbon. Fuel oil no. 2 is allowed during cold or hot startups, shutdowns and abnormal operations. The maximum consumption of each fuel is as follow:

- Coal: The maximum annual consumption of coal in the boilers is 941,700 tons per year based on the coal feed rate of 107.5 tons per hour for 8,760 hours per year.
- Biomass: The maximum annual consumption of wood in the boilers is 175,200 tons per year (or 1,883,400 MMBtu). The feed rate of wood to the boilers shall not exceed 20 tons per hour. When combusted with coal and/or TDF the combined maximum consumption rate is 233,000 pounds per hour (116.5 tons per hour).
- TDF: The maximum annual consumption of TDF in the boilers is 65,700 tons per year based on the permitted TDF feed rate of 7.5 tons per hour for 8,760 hours per year. TDF is fed to the boilers mixed with coal at a combined feed rate not to exceed 215,000 pounds per hour.
- Spec. used oil: A maximum of 3,000,000 gallons of spec used oil may be fed into the boilers during any rolling twelve month period.
- Spent activated carbon: Activated carbon has similar characteristic as coal. No quantity limit is included in CSP No. 0087-02-C for this type of fuel.
- Fuel oil no. 2: Fuel oil no. 2 (≤ 0.5% S by wt) is used to support combustion operations during hot or cold startups. Based on historical records, the maximum fuel oil no. 2 annual consumption for the boilers is 475,000 gallons per year.

The limestone dryer is permitted to burn fuel oil no. 2 or spec. used oil. The maximum consumption of each fuel is as follows:

- Fuel oil no. 2 (≤ 0.5% S by wt): Based on fuel oil no. 2 heat content of 140,000 BTU/ gallon, the maximum annual fuel oil no. 2 consumption in the dryer is 297,840 gallons per year or 34 gallons per hour for 8,760 hours per year (based on a combined dryer firing capacity of 4.75 MMBtu/hr for 1A and 1B). In reality, annual fuel oil no. 2 usage is approximately 35,000 gallons/year.
- Spec used oil: A maximum of 250,000 gallons of spec used oil is allowed for the limestone dryers per 12-month rolling period.

4.4 Production Rate and Capacity

- CFB boilers produce steam for the turbine generator which generates a maximum of 203 megawatts of electricity.
- The maximum design capacity of the coal processing equipment is 275 tons per hour with a maximum utilization rate of 107.5 tons per hour to the boilers. Based on the maximum utilization rate, the maximum annual capacity of the coal processing equipment is 941,700 tons per year.
- The total maximum design capacity for the two sets of limestone processing systems is 44 tons per hour. With utilization of 8,760 hour per year, the maximum annual capacity of limestone processing equipment is 385,440 tons per year.
- The facility uses one wet cooling tower with maximum water circulating rate of 104,000 gallons per minute and maximum drift rate of 0.002%. Total dissolved solids (TDS) in the circulating water will not exceed 52,000 mg/l.
- The ash handling system is designed to handle 140,100 tons of dry fly ash per year and 46,700 tons of dry bed ash per year, for a combined total of 186,800 tons of dry ash per year. Historically, the equipment has not reached a throughput greater than 81,300 tons of dry fly ash, 34,800tons of dry bed ash, and 116,100 tons of dry conditioned ash. For worst the case emissions scenario, the maximum rated capacities were used to estimate potential emissions.

4.5 Operational Limitation/Practices

In accordance with CSP No. 0087-02-C, the following operational limitations apply.

4.5.1 CFB Boilers

- The maximum sulfur content of fuel oil no. 2 is 0.5 percent by weight.
- The maximum amount of TDF consumption is 7.5 tons per hour.

- The spent activated carbon can only be obtained from the Board of Water Supply and Tesoro Refinery Hawaii.
- The maximum amount of spec. used oil consumption is 3,000,000 gallons per any rolling twelve month period.
- Air pollution control equipment should be operated at all times their associated equipment is operated and maintained to conditions as specified in the CSP No. 0087-02-C.

4.5.2 Coal Processing Equipment

The only operational limitation applied to the coal processing equipment is the utilization and maintenance of the baghouse as specified in CSP No. 0087-02-C. Potential emission calculation is based on the continuous operation of 24 hours per day for 365 days per year.

4.5.3 Limestone Processing Equipment

- The maximum sulfur content of fuel oil no. 2 for the dryer is 0.5 percent by weight.
- The maximum amount of spec. used oil consumption in the dryer is 250,000 gallons per any rolling twelve months period.
- Baghouses should be operated at all times that their associated equipment is operated and maintained to conditions as specified in the CSP No. 0087-02-C.

4.5.4 Cooling Tower

- No chromium-containing chemical is used in the cooling tower.
- The maximum circulating rate of the cooling tower is 104,000 gallons per minute.
- The maximum drift loss of the cooling tower is 0.002%.
- The maximum concentration of TDS in cooling tower water is 52,000 mg/l on an annual basis (change from 44,000 mg/l is being requested in this application).
- The maximum concentration of chlorine in the cooling tower water is 1 mg/l.

4.5.6 Ash Handling Equipment

Measures should be taken to control fugitive dust at all material transfer points, stockpiles, and throughout the workyard. Potential emission calculation from the ash handling equipment is based on the equipment maximum rated capacity with continuous operation of 24 hours per day for 365 days per year.

4.5.7 Fuel Oil Aboveground Storage Tank

The 60,000 gallon aboveground storage tank will only be used to store fuel oil no. 2.

5.0 DESCRIPTION OF PROCESSES

The Standard Industrial Classification Code (SICC) for this process is 4911. The facility produces a maximum of 203 MW electricity using two CFB boilers and a turbine generator and supply the electricity to HECO's substation through a 138 kV power line. The facility operates continuously for 24 hours per day and 365 days per year.

The main feed for the boilers is coal. Coal is currently purchased under a multi-year contract with an Indonesian supplier. Upon shipment unloading, coal is conveyed through covered overland conveyors to coal lowering wells and dropped to stockpiles. Fugitive PM emissions from the stockpiles are controlled with water spray while lowering wells include partial enclosures to reduce PM emissions. Front end loaders are used to transport coal from stockpiles to the coal reclaim hopper. From the hopper, coal is fed to the electric coal crusher via a covered conveyor. Particulate emissions from coal crushing operations are controlled by a baghouse. Upon crushing, coal is stored in silos with PM emissions controlled by a baghouse. As a fuel alternative, TDF is transported from the TDF stockpile to a TDF hopper. From the hopper, TDF is conveyed to coal silos through series of conveyors where it is stored with coal. Biomass, fuel oil #2, and specification used oil may also be used in the boilers.

Parallel to the coal preparation process, limestone is stored in active storage piles upon delivery to the site by truck. Front end loaders are used to transport limestone from storage piles to the limestone pulverizing building via a conveyor, where the limestone is dried and pulverized. Upon pulverizing process, the limestone travels via a pneumatic line to storage hoppers and feeders. PM emissions from the feeders are controlled by a total of four baghouses. The storage hoppers also vent to a baghouse for PM control. Fugitive emission control is accomplished by the use of covered conveyors and water spray on active storage piles and mobile equipment.

Coal and TDF from the silos are fed to the boilers. Biomass can also be fed to the boilers, though preparation (grinding, chipping, drying, etc.) will be completed off-site. Limestone from feeders and anhydrous ammonia from a storage tank are fed to the pollution control equipment of the boilers.

Each boiler includes a combustion zone, a hot cyclone, and a convective pass. Ammonia injection for NOx control occurs at the inlet to the cyclone. Limestone injection for SO_2 control takes place in the combustion zone. Combustion products passing the combustion zone move through the hot cyclone where the heavy particulate matter is separated from the hot exhaust gas. The hot exhaust gas enters the convective pass to produce superheated steam via heat transfer process. Superheated steam is supplied to the turbine generator at a rate of approximately 1.33 million pounds per hour to generate electricity. After exiting the turbine generator, the steam enters a condenser and recycled back to the convective pass as condensed steam. The temperature of the condenser water is maintained by the cooling tower. Bed ash is generated as byproduct of coal combustion and fly ash is collected from the filtered exhaust gas. After being separated from metallic compounds, portion of bed ash and fly ash are transported off site for disposal. The remaining portion of the bed ash and fly ash is mixed with water and transported off site as conditioned ash.

6.0 ALTERNATIVE OPERATING SCENARIOS/ PROCESSES/ PRODUCTS

6.1 Coal Delivery via Haul Trucks

Coal delivery via haul trucks may be used as an alternate to the overland conveyor. For this alternative scenario, haul trucks will deliver coal from the draft harbor, travel along the industrial paved road, and unload the supply to the stockpiles. Fugitive emissions resulting from this alternative scenario will be similar to the normal operating scenario since the addition of trucks traveling on paved roads will be offset by the reduction in PM emissions from the overland conveyor, lowering wells, and coal conveyors.

6.2 Stockpiling Conditioned Ash

In the event that trucks for off-site transportation are unavailable, AES may stockpile the conditioned ash in the yard. The stockpile capacity is limited to 10,000 tons at any given time. For the worst case scenario, maximum potential emissions were estimated based on the maximum conditioned ash handling equipment capacity of 186,800 tons/year. The table below summarizes the TSP emission differences between the normal and alternative operation related to the ash handling.

NORMAL OPERATION				ALTERNATIVE OPERATION			
No.	Activity	Potential TSP Emission		No.	Activity	Potential TSP Emission	
1	Direct load to trucks for off-site transport	0.0054	tpy	1	Conditioned ash is loaded into a loader	0.0054	tpy
2	Trucks traveling on paved road to transport conditioned ash off-site	0.0127	tpy	2	Loader travelling on unpaved road from the silo to the yard(1)	0.6206	tpy
				3	Loader unloading to storage piles	0.0054	tpy
				4	Wind erosion on the conditioned ash pile (2)	0.0036	tpy
	TOTAL	**0.0182**	**tpy**		**TOTAL**	**0.6351**	**tpy**

Note:

1. Calculations were based on maximum capacity of 186,800 tons/year, with one round trip distance from conditioned ash mixer to the yard of 500 feet.
2. Assume conditioned ash's moisture content is 25% by weight (Source: AES operator)

7.0 FACILITY EMISSIONS

The following are identified as sources of emissions within the facility:

- Coal Processing
- Limestone Processing
- Storage Tanks
- Steam Boilers
- Cooling Tower
- Ash Handling

Potential emissions from all operations are calculated based on continuous operation of 8,760 hours per year. Boiler emissions from coal combustion were calculated using source test and CEMS data. Fuel oil combustion emissions from the boilers and all other support activity emissions were calculated using AP-42 emission factors.

The process flow diagram and emission points can be viewed in Figure 3.

The summary of facility-wide controlled potential emissions is presented in the following table:

Pollutant	Potential Emissions (TPY)*	Potential Emissions (lb/hr)*
Criteria Pollutants		
SO_2	2,835.65	647.41
NOx	1,039.44	237.31
CO	1,789.54	408.57
PM Total	388.68 **	89.80 **
PM 10	156.83 **	36.08 **
PM 2.5	50.26 **	35.60 **
VOC	141.08	32.21
Greenhouse Gases		
Total CO_2e	1,691,605	-
HAPs: Metals		
Antimony	8.51E-03	1.94E-03
Arsenic	1.93E-01	4.42E-02

Pollutant	Potential Emissions (TPY)*	Potential Emissions (lb/hr)*
Barium* Not HAP	8.60E-03	2.00E-03
Beryllium	2.94E-01	6.70E-02
Cadmium	2.40E-02	5.49E-03
Chromium	1.23E-01	2.81E-02
Cobalt	4.71E-02	1.08E-02
Lead	2.50E+01	5.70E+00
Manganese	2.32E-01	5.27E-02
Mercury	7.45E-01	1.70E-01
Nickel	1.34E-01	3.06E-02
Selenium	6.12E-01	1.40E-01
HAPS: Other		
1,1,1-Trichloroethane	2.93E-02	3.97E-02
1,2-Dibromoethene	5.18E-02	7.05E-02
1,2-Dichloroethane	2.73E-02	3.72E-02
1,2-Dichloropropane	3.11E-02	4.23E-02
2,4,6-Trichlorophenol	2.07E-05	2.82E-05
2,4-Dinitrophenol	1.70E-04	2.31E-04
2,4-Dinitrotoluene	1.32E-04	3.01E-05
2-Butanone (MEK)	1.84E-01	4.19E-02
2-Chloroacetophenone	3.30E-03	7.53E-04
4-Nitrophenol	1.04E-04	1.41E-04
Acetaldehyde	7.82E-01	1.06E+00
Acetophenone	7.06E-03	1.61E-03
Acrolein	3.77E+00	5.13E+00
Benzene	3.96E+00	5.38E+00
Benzyl chloride	3.30E-01	7.53E-02
Bis(2-ethylhexyl)phthalate (DEHP)	3.44E-02	7.85E-03
Bromoform	1.84E-02	4.19E-03
Bromomethane	7.64E-02	1.92E-02
Carbon disulfide	6.12E-02	1.40E-02
Carbon tetrachloride	4.24E-02	5.77E-02
Chlorine	1.04E-3	1.01E+00
Chlorobenzene	3.11E-02	4.23E-02
Chloroform	2.98E-02	3.59E-02
Chloromethane	2.51E-01	5.70E-02

Pollutant	Potential Emissions (TPY)*	Potential Emissions (lb/hr)*
Cumene	2.50E-03	5.70E-04
Cyanide	1.18E+00	2.69E-01
Dichloromethane	2.73E-01	3.72E-01
Dimethyl sulfate	2.26E-02	5.16E-03
Ethyl benzene	4.65E-02	3.97E-02
Ethyl chloride	1.98E-02	4.52E-03
Ethylbenzene	4.65E-02	3.97E-02
Ethylene dibromide	5.18E-02	7.05E-02
Ethylene dichloride	2.73E-02	3.72E-02
Formaldehyde	4.16E+00	5.64E+00
Hexane	3.15E-02	7.20E-03
Hydrogen Chloride	1.88E+01	4.39E+00
Isophorone	2.73E-01	6.24E-02
Methyl bromide	7.64E-02	1.92E-02
Methyl chloride	2.51E-01	5.70E-02
Methyl ethyl ketone	1.84E-01	4.19E-02
Methyl hydrazine	8.00E-02	1.83E-02
Methyl methacrylate	9.42E-03	2.15E-03
Methyl tert butyl ether	1.65E-02	3.76E-03
Methylene chloride	2.73E-01	3.72E-01
Pentachlorophenol	4.80E-05	6.54E-05
Phenol	4.80E-02	6.54E-02
Phosphorus	2.54E-02	3.46E-02
Propanal	1.84E-01	8.23E-02
Propionaldehyde	1.84E-01	8.23E-02
Styrene	1.79E+00	2.43E+00
Tetrachloroethene	3.58E-02	4.87E-02
Tetrachloroethylene	3.58E-02	4.87E-02
Toluene	8.69E-01	1.18E+00
Trichloroethene	2.83E-02	3.84E-02
Vinyl acetate	3.58E-03	8.17E-04
Vinyl Chloride	1.70E-02	2.31E-02
Xylenes	2.36E-02	3.20E-02
HAPs: POM (including PAH)		
Acenaphthene	8.65E-04	1.17E-03

Pollutant	Potential Emissions (TPY)*	Potential Emissions (lb/hr)*
Acenaphthylene	4.71E-03	6.41E-03
Anthracene	2.83E-03	3.84E-03
Benz(a)anthracene	6.28E-05	8.34E-05
Benzo(a)anthracene	6.28E-05	8.34E-05
Benzo(a)pyrene	2.45E-03	3.33E-03
Benzo(b,j,k)fluoranthene	2.79E-04	3.79E-04
Benzo(g,h,i)perylene	8.85E-05	1.19E-04
Biphenyl	8.00E-04	1.83E-04
Chrysene	5.08E-05	4.88E-05
Dibenzo(a,h)anthracene	9.21E-06	1.17E-05
Fluoranthene	1.51E-03	2.05E-03
Fluorene	3.20E-03	4.36E-03
Indeno(1,2,3,c,d)pyrene	8.28E-05	1.12E-04
5-Methyl chrysene	1.04E-05	2.37E-06
Naphthalene	9.18E-02	1.24E-01
Phenanthrene	6.60E-03	8.97E-03
Pyrene	3.49E-03	4.74E-03
Other Polycyclic organic matter (POM)	8.14E-04	1.86E-04
Hazardous Air Pollutants: PCB		
Decachlorobiphenyl	2.54E-07	3.46E-07
Dichlorobiphenyl	6.97E-07	9.48E-07
Heptachlorobiphenyl	6.22E-08	8.46E-08
Hexachlorobiphenyl	5.18E-07	7.05E-07
Monochlorobiphenyl	2.07E-07	2.82E-07
Pentachlorobiphenyl	1.13E-06	1.54E-06
Tetrachlorobiphenyl	2.35E-06	3.20E-06
Trichlorobiphenyl	2.45E-06	3.33E-06
HAPs: Dioxins & Furans		
Dioxins & Furans	3.07E-06	4.08E-06
Other Pollutants		
Fluorides	0.876	0.2
Sulfuric Acid Mist	17.958	4.1

* Detailed emission calculations are provided in Tables 1 – 31.

** Differences in potential emissions in comparison with the previous air permit renewal are due to the use of updated meteorological data to update constants used to determine emission factors in Tables 4,5,7,8, 10, 23 and 28.

8.0 APPLICABLE REQUIREMENTS

8.1 Hawaii Administrative Rules (HAR)

- HAR §11-59 Ambient Air Quality Standards
- HAR §11-60.1 Subchapter 1 General Requirements
- HAR §11-60.1 Subchapter 2 General Prohibitions
    - 11-60.1-5 Permit Conditions
    - 11-60.1-11 Sampling, Testing, and Reporting Methods
    - 11-60.1-16 Prompt Reporting of Deviations
    - 11-60.1-31 Applicability
    - 11-60.1-32 Visible Emissions
    - 11-60.1-33 Fugitive Dust
    - 11-60.1-38 Sulfur Oxides from Fuel Combustion
- HAR §11-60.1 Subchapter 5 Covered Sources
- HAR §11-60.1 Subchapter 6 Fees for Noncovered Sources, Covered Sources and Agricultural Burning
    - 11-60.1-111 Definitions
    - 11-60.1-112 General Fee Provisions for Covered Sources
    - 11-60.1-113 Application Fees for Covered Sources
    - 11-60.1-114 Annual Fees for Covered Sources
    - 11-60.1-115 Basis of Annual Fees for Covered Sources
- HAR §11-60.1 Subchapter 7 Prevention of Significant Deterioration
- HAR §11-60.1 Subchapter 8 Standards of Performance for Stationary Sources
- HAR §11-60.1-161 New Source Performance Standards
- HAR §11-60.1 Subchapter 9 Hazardous Air Pollutants
- HAR §11-60.1 Subchapter 10 Field Citations
- HAR §11.60.1 Subchapter 11 Greenhouse Gas Emissions

8.2 Federal Rules, Regulations, and Standards (CFR)

- 40 CFR Part 50 National Primary and Secondary Air Quality Standards
- 40 CFR Part 52.21 Prevention of Significant Deterioration of Air Quality (PSD)
- 40 CFR Part 60 New Source Performance Standards (NSPS)
    - Subpart A NSPS General Provisions

- Subpart Da Standards of Performance for Electric Utility Steam Generating Units for which construction is commenced after September 18, 1978
    - Subpart Kb Standards of Performance for Volatile Organic Liquid Storage Vessels
    - Subpart Y Standards of Performance for Coal preparation Plants
    - Subpart OOO Standards of Performance for Nonmetallic Mineral Processing Plants

- 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants
- 40 CFR Part 64 Compliance Assurance Monitoring
- 40 CFR Part 68 Accidental Release Prevention Requirements
- 40 CFR Part 70 State Operating Permit Programs
- 40 CFR Part 98 Mandatory GHG Reporting

8.3 PSD Requirements

This facility is subject to Prevention of Significant Deterioration (PSD) requirements as defined in 40 CFR 52.21 and HAR 11.60-1 Subchapter 7 according to the previous terms and conditions of PSD No. HI 88-02. No new PSD review is applicable to the facility since there is no modification that will generate an emission increase that is significant as defined in 40 CFR 52.21 and HAR 11.60-1 Subchapter 7.

9.0 AMBIENT AIR QUALITY ANALYSIS

Ambient air quality impact analyses (AAQA) were performed as part of the initial CSP application to show compliance with ambient air quality standards. No major changes resulting in emission increases of criteria pollutants from the boiler stack are proposed with this renewal. Therefore, we conclude that the previously conducted AAQA is still applicable.

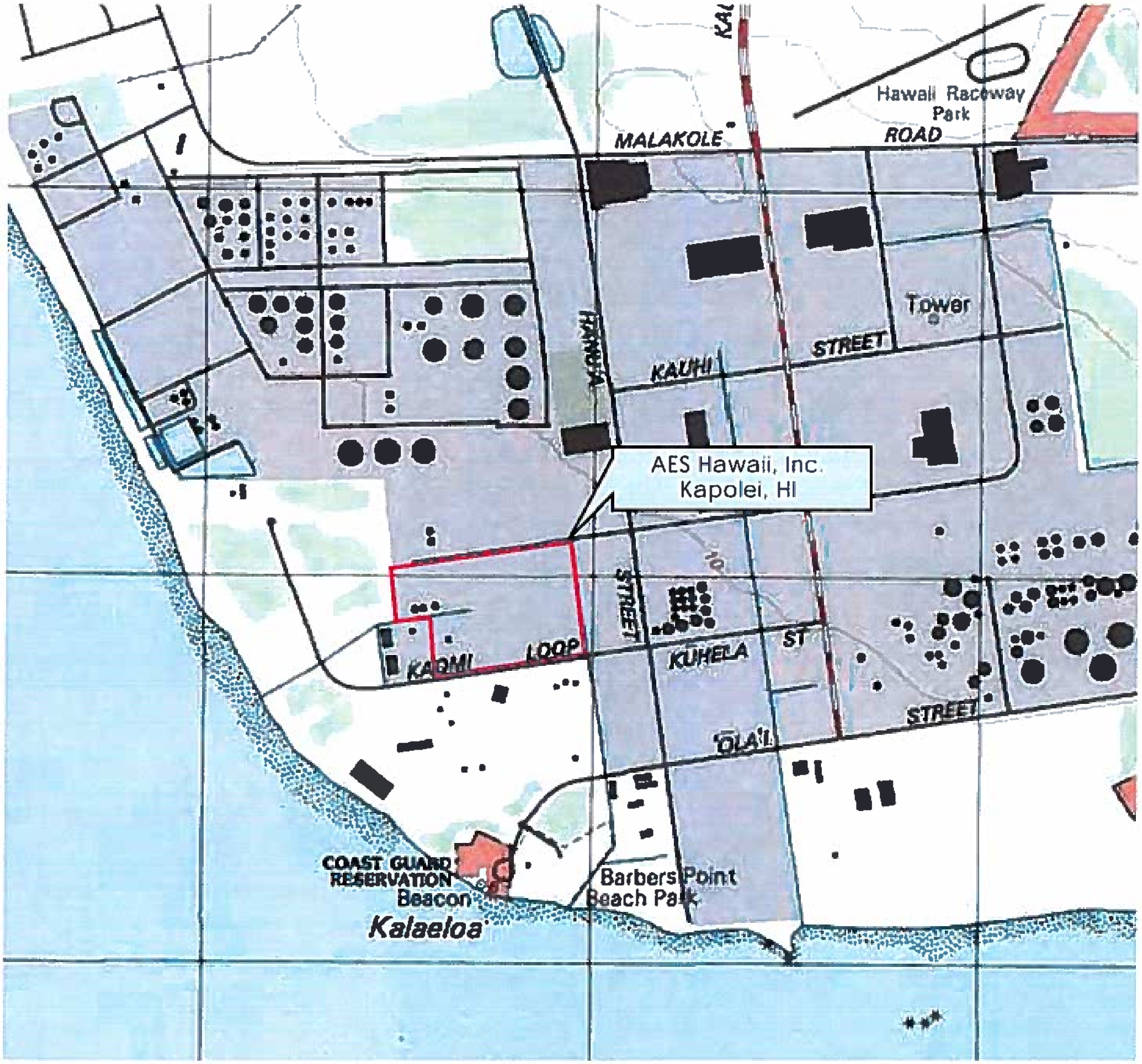
10.0 COMPLIANCE PLAN

A compliance plan, form C-1, and compliance certification, form C-2, are attached to complete this application.

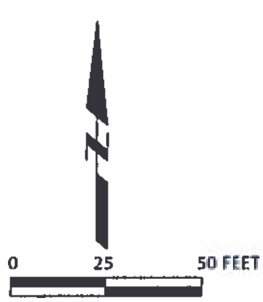
11.0 APPLICATION FEE

Attached is a check in the amount of $1,000.00 to cover the application fee for a significant modification to a PSD source.

Figures



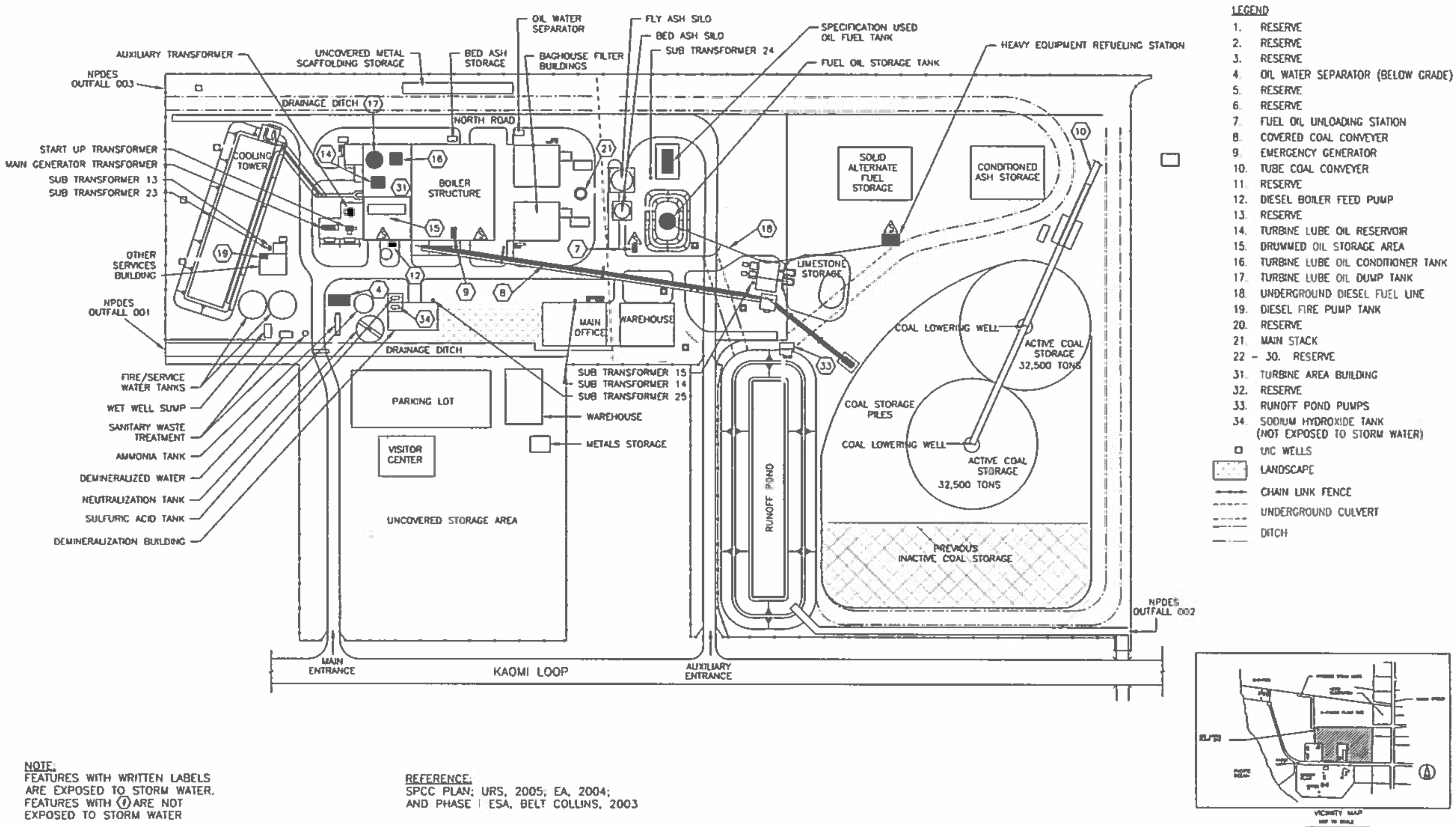
Base map generated using TOPO ® ©2002 National Geographic



Site Vicinity Map

AES Hawaii, Inc., Kapolei, Hawaii

Figure 1



NOTE:
FEATURES WITH WRITTEN LABELS ARE EXPOSED TO STORM WATER. FEATURES WITH ⓘ ARE NOT EXPOSED TO STORM WATER

REFERENCE:
SPCC PLAN; URS, 2005; EA, 2004; AND PHASE I ESA, BELT COLLINS, 2003

REVISION HISTORY			
NO.	DESCRIPTION	DATE	APPROVED

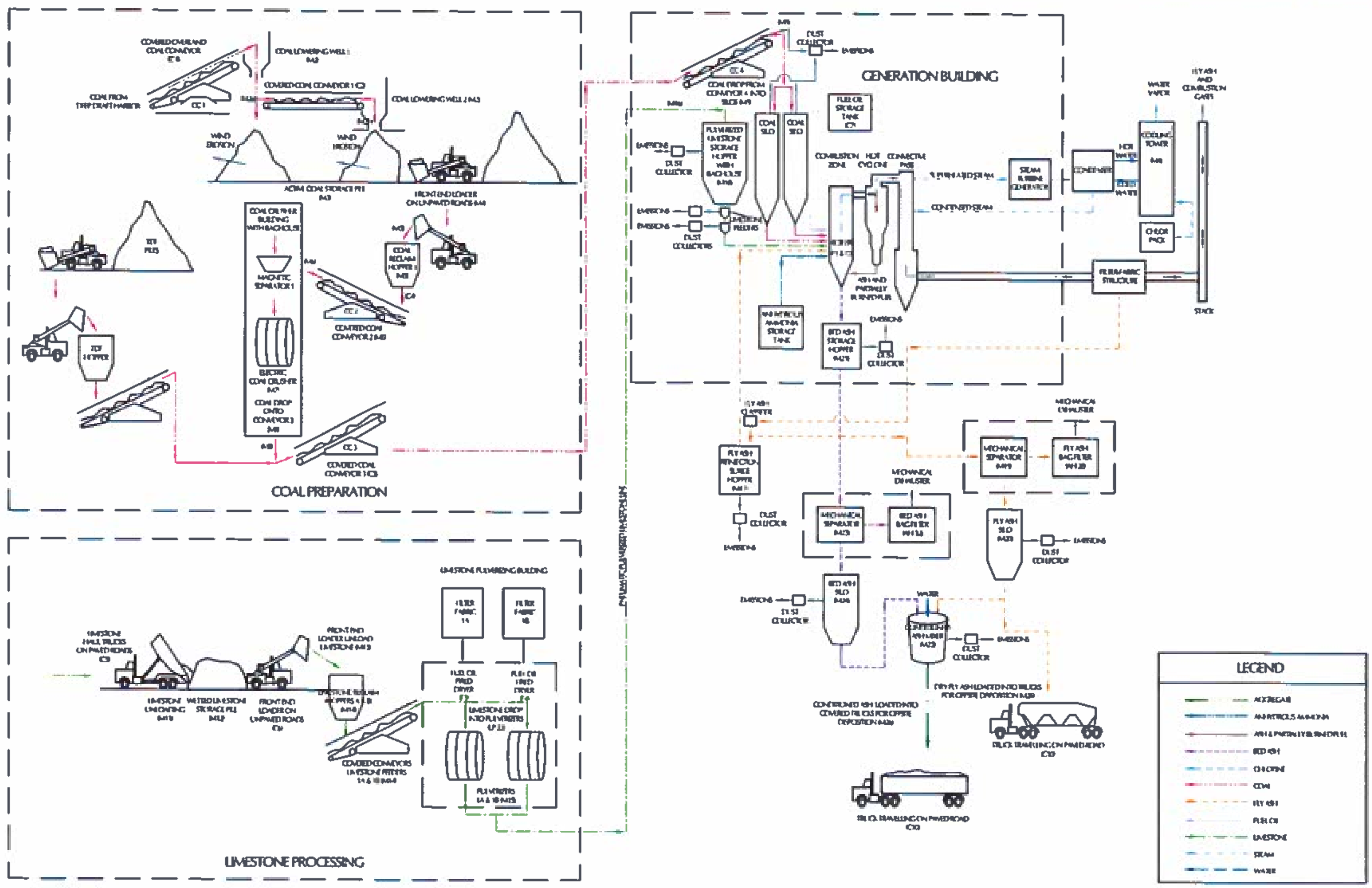
LICENSED PROFESSIONAL
PROFESSIONAL #

SIGNATURE DATE

SITE LAYOUT MAP
AES BARBERS POINT COGENERATION PLANT
COVERED SOURCE PERMIT RENEWAL APPLICATION

AES HAWAII, INC.
91-086 KAOMI LOOP
KAPOLEI, HAWAII 96707

Figure 2



REVISION HISTORY			
NO.	DESCRIPTION	DATE	APPROVED
1	Eliminated Aggregate & Ash Processes; Added Dust Controls and TDF Loading Process	6/4/07	

LICENSED PROFESSIONAL
PROFESSIONAL #

SIGNATURE DATE

FLOW PROCESS DIAGRAM
AES BARBERS POINT COGENERATION PLANT
COVERED SOURCE PERMIT RENEWAL APPLICATION

AES HAWAII, INC.
91-086 KAOMI LOOP
KAPOLEI, HAWAII 96707

FIGURE 3

Tables

Table 1: AES HAWAII PROCESS INPUT SUMMARY
AES Hawaii, Inc.
CSP No. 0087-02-C

	Coal processing equipment	Input		Emission Factor	Control	Efficiency (%)
	Conveyor Transfer					
C1	Coal conveyor transfer point	941,700	ton/yr	AP42.11.19.2	covered	70
C2	Coal conveyor transfer point	941,700	ton/yr	AP42.11.19.2	covered	70
M6	CC2 transfer point to Crusher Building	941,700	ton/yr	AP42.11.19.2	covered	70
C3	CC3 transfer point	941,700	ton/yr	AP42.11.19.2	covered	70
M9	CC4 to coal silos	941,700	ton/yr	AP42.13.2.4	covered	70
	Coal drops					
M2a	well1 drop to storage pile and C2	941,700	ton/yr	AP42.13.2.4	lowering well	75
M2b	well2 drop to storage pile	941,700	ton/yr	AP42.13.2.4	lowering well	75
C4	hopper 1 drop to CC2	941,700	ton/yr	AP42.13.2.4	water	50
M8	Coal drop to CC3	941,700	ton/yr	AP42.13.2.4	water	50
	Truck Unloading					
M5	Loader drop to hopper1	941,700	ton/yr	AP42.13.2.4	water	50
	Storage piles					
M3	Coal Storage Piles	941,700	ton/yr	AP42.13.2.5	water	50
	Crushers					
M7	Electric coal crusher	941,700	ton/yr	AP42.11.19.2	baghouse	99
	Trucks on Unpaved Roads					
M4	Front End Loaders	941,700	ton/yr	AP42.13.2.2	water	50
	Silo Loading					
M9	Coal Silo Loading	941,700	ton/yr	AP42.11.12.1	dust collector	99

	Lime processing equipment	Input		Emission Factor	Control	Efficiency (%)
	Trucks on Paved Roads					
C5	Haul Trucks	44	tons/hr	AP42.13.2.2	water	50
	Trucks on Unpaved Roads					
C6	Front End Loaders	44	tons/hr	AP42.13.2.2	water	50
	Truck Unloading					
M11	Haul truck unloading to storage piles	44	tons/hr	AP42.11.19.2	water	50
M13	ader unloading to reclaim drop traps/convey	44	tons/hr	AP42.11.19.2	water	50
	Storage pile					
M12	Limestone storage pile	44	tons/hr	AP42.13.2.5	water	50
	Conveyor Transfer					
M14	Limestone conveyor feeder	44	tons/hr	AP42.11.19.2	covered	70
	Dryer					
F3,F4	fuel oil	4.75	mmbtu/hr	AP42.1.3	filter fabric	99
C8*	spec used oil	250,000	gal/yr	AP42.1.11	filter fabric	99
	Pulverizer (fine crushing)					
M15	Limestone pulverizer	44	tons/hr	AP42.11.19.2	filter fabric	99
	Hopper Loading					
M16	Limestone Hopper Handling	44	tons/hr	AP42.11.12.1	dust collector	99

Storage Tanks		Input		Emission Factor	Control	Efficiency (%)
C7	Fuel oil storage tank			AP42 7.1	none	---

Steam Boilers		Input		Emission Factor	Control	Efficiency (%)
	Coal Fired	215,000	lb/hr	Stack Testing, AP24.1.1	Lime Injection, SNCR System, Baghouse	75, 70, 99
	Fuel Oil 2 Fired	475,000	gal/yr	AP42.1.3		
	Spec Used Oil Fired	3,000,000	gal/yr	AP42.1.11		
	Biomass Fired	1,883,400	MMBtu/yr	AP42.1.6		

Cooling Tower		Input		Emission Factor	Control	Efficiency (%)
M1	Cooling Tower	104,000	gal/min	AP42 13.4	none	---

Ash handling		Input		Emission Factor	Control	Efficiency (%)
	Material Loading					
M21	Bed Ash Hopper Loading	46,700	tons/yr	AP42.11.12.1	dust collector	99
M17	Fly Ash Reinjection Surge Hopper Loading	140,100	tons/yr	AP42.11.12.1	dust collector	99
M24	Bed Ash Silo Loading	46,700	tons/yr	AP42.11.12.1	dust collector	99
M20	Fly Ash Silo Loading	140,100	tons/yr	AP42.11.12.1	dust collector	99
M25	Conditioned Ash Mixer Loading	186,800	tons/yr	AP42.11.12.1	dust collector	99
	Separators					
M23	Bed Ash Mechanical Separator	46,700	tons/yr	AP42.11.19.2.4	dust collector	99
M19	Fly Ash Mechanical Separator	140,100	tons/yr	AP42.11.19.2.4	dust collector	99
	Ash Drops					
M26	Conditioned Ash Drop into Trucks	186,800	tons/yr	AP42.11.12.1	water	50
	Paved Roads					
C10	Ash Trucks on Paved Roads	186,800	tons/yr	AP42.13.2.1	water	50

TABLE 2: POTENTIAL EMISSIONS CALCULATION FROM COAL HANDLING
Coal Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Operating hours	8,760	hours/year	24 hours per day, 365 days per year
Max. coal consumption	941,700	tons/year	AES Hawaii, Inc.
Hourly coal processing equipment capacity	275	tons/hour	AES Hawaii, Inc.

Activity	No. of Equipment	Emission Factor			Source
		PM-2.5	PM-10	TSP	
		lb/ton	lb/ton	lb/ton	
Conveyor Transfer Point	5	0.0011	0.0011	0.003	EPA AP-42, Table 11.19.2-2 08/04 Edition
Truck Unloading	1	0.0001	0.0001	0.000225	EPA AP-42, Table 11.19.2-2 08/04 Edition
Crushing	1	0.0024	0.0024	0.0054	EPA AP-42, Table 11.19.2-2 08/04 Edition
Coal Silo Loading	1	0.0024	0.0024	0.0054	EPA AP-42, Table 11.19.2-2 08/04 Edition

Activity	Uncontrolled Emission							Controlled Emission					
	PM-2.5		PM-10		TSP		Control Efficiency	PM-2.5		PM-10		TSP	
	lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year		lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year
Conveyor Transfer Point	1.5125	2.589675	1.5125	2.589675	4.125	7.06275	70%	0.45	0.78	0.454	0.777	1.238	2.119
Truck Unloading	0.0275	0.047085	0.0275	0.047085	0.061875	0.1059413	50%	0.01	0.02	0.014	0.024	0.031	0.053
Crushing	0.66	1.13004	0.66	1.13004	1.485	2.54259	99%	0.01	0.01	0.007	0.011	0.015	0.025
Coal Silo Loading	0.66	1.13004	0.66	1.13004	1.485	2.54259	99%	0.01	0.01	0.007	0.011	0.015	0.025

NOTE:
The lb/hour emissions are estimated based on equipment hourly capacity.
The tons/year emissions are estimated based on facility's maximum coal consumption per year.
Control efficiency of 70% is applied to account for the covered conveyor
Control efficiency of 50% is applied to account for the water application
Control efficiency of 99% is applied to account for baghouses
Conservatively assumed PM2.5 = PM10
TSP for Truck Unloading, because no data in AP42, was scaled up from PM10 based on same ratio as for coal silo handling

TABLE 3: POTENTIAL EMISSIONS CALCULATION FROM COAL DROPS
Coal Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Maximum annual coal usage	941,700	tons/year	AES Hawaii, Inc.
Operating hours	8,760	hours/year	24 hours per day, 365 days per year
Number of Uncontrolled Drops	2	-	Drops to storage piles and conveyors
Hourly coal processing equipment capacity	275	tons/hour	AES Hawaii, Inc.

E = k*.0032*(((U/5)^1.3)/(M/2)^1/4))
where E = emission factor (lb/ton)
k = particle size multiplier

Source: AP42, 13.2.4, 11/06 ed.
M = moisture content (%)
U = mean wind speed (mph)

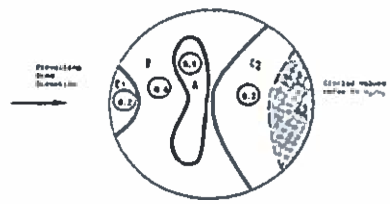
	Value	Source
k (TSP)	0.74	AP42, 13.2.4, (11/06)
k (PM-10)	0.35	AP42, 13.2.4, (11/06)
k (PM-2.5)	0.2	AP42, 13.2.4, (11/06)
U	8.1	WRCC, See Appendix C
M	15.36	AES Hawaii, Inc.

Contaminant	Emission Factor	Uncontrolled Emission		Control Efficiency	Controlled Emission	
	lb/ton	lb/hr	ton/year		lb/hr	tons/year
2 Drop Points with 75% control						
TSP	0.000255	0.14	0.24	75%	0.04	0.06
PM-10	0.000121	0.07	0.11	75%	0.02	0.03
PM-2.5	0.000069	0.04	0.07	75%	0.01	0.02
2 Drop Points with 50% control						
TSP	0.000255	0.14	0.24	50%	0.07	0.12
PM-10	0.000121	0.07	0.11	50%	0.03	0.06
PM-2.5	0.000069	0.04	0.07	50%	0.02	0.03

NOTE:
The lb/hour emissions are estimated based on equipment hourly capacity.
The tons/year emissions are estimated based on facility's maximum coal consumption per year.
Control efficiency of 75% is applied to account for the lowering wells.
Control efficiency of 50% is applied to account for the water applications.

TABLE 4: POTENTIAL EMISSIONS CALCULATION FROM COAL STORAGE PILES
Coal Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Diameter stockpile	200	ft	AES Hawaii
Radius stockpile	100	ft	AES Hawaii
Height stockpile	40	ft	AES Hawaii
Weight/pile	22,000	tons	AES Hawaii
Bulk density	3.5	lb/ft^3	AES Hawaii
Total exposed area (2 stockpiles)	67,672	ft^2	Calculated
Threshold friction velocity	0.55	m/s	AP42 Table 13.2.5.2 11/06 Edition
N	365	-	Assume daily disturbance



Pile Area	Us/Ur	%	Area	Units
A	0.9	12%	8,121	ft^2
B	0.6	48%	32,483	ft^2
C	0.2	40%	27,069	ft^2
Total			67,672	ft^2

February 2015[2]					
	Wind speed, Ur		Friction Velocities (U*) =0.1Us		
Day	miles/hr	m/s	0.2	0.6	0.9
1	13	5.8	0.116	0.349	0.523
2	21	9.4	0.188	**0.563**	**0.845**
3	23	10.3	0.206	**0.617**	**0.925**
4	22	9.8	0.197	**0.590**	**0.885**
5	24	10.7	0.215	**0.644**	**0.966**
6	21	9.4	0.188	**0.563**	**0.845**
7	13	5.8	0.116	0.349	0.523
8	13	5.8	0.116	0.349	0.523
9	18	8.0	0.161	0.483	**0.724**
10	25	11.2	0.224	**0.671**	**1.006**
11	21	9.4	0.188	**0.563**	**0.845**
12	10	4.5	0.089	0.268	0.402
13	21	9.4	0.188	**0.563**	**0.845**
14	30	13.4	0.268	**0.805**	**1.207**
15	9	4.0	0.080	0.241	0.362
16	8	3.6	0.072	0.215	0.322
17	9	4.0	0.080	0.241	0.362
18	12	5.4	0.107	0.322	0.483
19	14	6.3	0.125	0.376	**0.563**
20	8	3.6	0.072	0.215	0.322
21	12	5.4	0.107	0.322	0.483
22	13	5.8	0.116	0.349	0.523
23	13	5.8	0.116	0.349	0.523
24	10	4.5	0.089	0.268	0.402
25	10	4.5	0.089	0.268	0.402
26	14	6.3	0.125	0.376	**0.563**
27	10	4.5	0.089	0.268	0.402
28	12	5.4	0.107	0.322	0.483

NOTES:
(1)Us/Ur is the ratio of surface wind speed to approach wind speed
(2)February 2015 data was chosen to represent fastest wind speed during the year based on monthly average speeds in Appendix C.
Potential emission calculation above is performed based on guidance provided by EPA AP42
Section 13.2.5 November 2006 edition
(3)Control factor of 50% is applied to account for water application
(4) Aerodynamic Particle Size Multipliers For AP 42 13.2.5-2 Equation 2 November 2006 edition
(5) Numbers in bold used in emission calculations, when wind speeds on a given day exceed frictional velocities for any pile (A, B, or C).

Pile	Day	U*>0.54	U*-0.55	Potential erosion (P)	Pile surface area	Emission = k*P*A	
				(g/m2)	m2	gr	tons
B	2	0.563	0.013	0.34	3,019	1,032	0.00114
B	3	0.617	0.067	1.93	3,019	5,835	0.00643
B	4	0.590	0.040	1.10	3,019	3,308	0.00365
B	5	0.644	0.094	2.85	3,019	8,614	0.00950
B	6	0.563	0.013	0.34	755	258	0.00028
B	10	0.671	0.121	3.86	755	2,911	0.00321
B	11	0.563	0.013	0.34	755	258	0.00028
B	13	0.563	0.013	0.34	755	258	0.00028
B	14	0.805	0.255	10.13	755	7,645	0.00843
A	2	0.845	0.295	12.42	755	9,372	0.01033
A	3	0.925	0.375	17.56	755	13,252	0.01461
A	4	0.885	0.335	14.89	755	11,241	0.01239
A	5	0.966	0.416	20.41	755	15,405	0.01698
A	6	0.845	0.295	12.42	755	9,372	0.01033
A	9	0.724	0.174	6.12	755	4,616	0.00509
A	10	1.006	0.456	23.45	755	17,699	0.01951
A	11	0.845	0.295	12.42	755	9,372	0.01033
A	13	0.845	0.295	12.42	755	9,372	0.01033
A	14	1.207	0.657	41.46	755	31,296	0.03450
A	19	0.563	0.013	0.34	755	258	0.00028
A	26	0.563	0.013	0.34	755	258	0.00028

Total PM Emission per day	Uncontrolled	0.00636
Total PM Emissions per year	Uncontrolled	2.32258
Total PM Emissions per year(Controlled)[3]	Controlled[3]	1.16129
PM 10 Emissions per year (50% of total PM[4])	Uncontrolled	1.161288019
	Controlled[3]	0.580644009
PM 2.5 Emissions per year (7.5% of total PM[4])	Uncontrolled	0.174193203
	Controlled[3]	0.087096601

Pounds Per hour		lb/hr
Total PM Emissions per hour	Uncontrolled	0.0003
	Controlled[3]	0.0001
PM 10 Emissions per hour (50% of total PM[4])	Uncontrolled	0.0001
	Controlled[3]	6.6E-05
PM 2.5 Emissions per hour (7.5% of total PM[4])	Uncontrolled	2.0E-05
	Controlled[3]	9.9E-06

TABLE 5: POTENTIAL EMISSIONS CALCULATION FROM COAL FRONT END LOADERS TRAVELING ON UNPAVED ROADS

Coal Processing

AES Hawaii, Inc.

CSP No. 0087-02-C

$E = k(s/12)^a(W/3)^b$ — AP 42, 13.2.2 Equation (1a) November 2006 ed.

$E_{ext} = ((365-p)/365 * k(s/12)^a(W/3)^b$ — AP 42, 13.2.2 Equation (2) November 2006 ed.

where E = Emission factor (lb/vehicle miles traveled)
E_{ext} = annual size-specific emission factor extrapolated for natural mitigation (lb/VMT)
k,a,b,c = constant (lb/VMT)
s = surface material silt content (%)
W = mean vehicle weight (tons)
p = number of days with at least 0.01 inches of precipitation per year

Parameter	Value			Source
	PM-2.5	PM-10	PM-30	
a	0.9	0.9	0.7	AP42, Table 13.2.2-2 (11/06)
b	0.45	0.45	0.45	AP42, Table 13.2.2-2 (11/06)
k	0.15	1.5	4.9	AP42, Table 13.2.2-2 (11/06)
s	5.1			AP42, Table 13.2.2-2 (11/06)
W	60			AES Hawaii, Inc.
p	95			WRCC, see Appendix C

	PM-2.5	PM-10	PM-30
Emission Factor (lb/VMT)	0.267365	2.673651	10.36411
Annual Size Specific Extrapolated for Natural Mitigation (lb/VMT)	0.197777	1.97777	7.666599

	Value	Unit
Loader load	20	ton/trip
Distance traveled by truck	0.02	miles/trip
Max annual coal usage	941,700	ton/year
Facility run time	8,760	hr/year
# of trip per year	47,085	trip/year
Total distance VMT	942	miles/year
Coal processing equipment hourly capa	275	tons/hour
Hourly VMT	0.275	miles/hr

Emissions	PM-2.5		PM-10		PM-30	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Uncontrolled	0.054	0.093	0.544	0.932	2.108	3.611
Controlled[1]	0.027	0.047	0.272	0.466	1.054	1.805

Note:
(1) 50% control factor is applied to account for water spray.

TABLE 6: POTENTIAL METALS EMISSIONS CALCULATION FROM COAL PROCESSING
Coal Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	lb/hr	ton/year
Total Controlled PM Emissions from Coal Processing (Sum of Table 2 through 5)	2.46	5.37

Metals	Lab Analytical Results 11/8/2000	Potential Emissions*		HAP?
	mg/kg	lb/hr	tons/year	
Antimony	0.08	1.97E-07	4.30E-07	Yes
Arsenic	2.8	6.88E-06	1.50E-05	Yes
Barium	34	8.36E-05	1.83E-04	No
Beryllium	0.1	2.46E-07	5.37E-07	Yes
Cadmium	0.02	4.92E-08	1.07E-07	Yes
Chromium	6	1.47E-05	3.22E-05	Yes
Cobalt	2.9	7.13E-06	1.56E-05	Yes
Copper	3	7.37E-06	1.61E-05	No
Lead	2	4.92E-06	1.07E-05	Yes
Manganese	7	1.72E-05	3.76E-05	Yes
Mercury	0.03	7.37E-08	1.61E-07	Yes
Molybdenum	0.8	1.97E-06	4.30E-06	No
Nickel	8	1.97E-05	4.30E-05	Yes
Selenium	0.3	7.37E-07	1.61E-06	Yes
Silver	0.02	4.92E-08	1.07E-07	No
Vanadium	13	3.20E-05	6.98E-05	No
Zinc	12	2.95E-05	6.44E-05	No

NOTE:
* - Estimated potential emissions for metals in fugitive PM emissions.

TABLE 7: POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE HAUL TRUCKS TRAVELING ON PAVED ROADS
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

$E_{ext} = [k*(sL)^{0.91}*(W)^{1.02}]*(1-P/(4N))$ AP42,13.2.1 Equation (2) January 2011 edition

where:
E_{ext} = annual average emission factor in the same units as k
k = particle size multiplier for particle size of interest (lb/VMT)
sL = road surface silt loading (g/m2)
W = average weight of vehicles traveling the road (tons)
P = number of days with at least 0.01 inches of precipitation per year
N = number of days in the averaging period (365 days for annual)

Parameter	Value			Units	Source
	PM-2.5	PM-10	PM-30		
k	0.00054	0.0022	0.011	lb/VMT	AP42, Table 13.2.1-1 (1/11)
sL	0.037	0.037	0.037	g/m2	CARB methodology 7.9 for paved road
W	28	28	28	tons	AES Hawaii, Inc.
P	95	95	95	days	WRCC data (see Appendix C)
N	365	365	365	days	Annual averaging period
E_{ext}	0.0008	0.0031	0.0153	lb/VMT	AP42, Table 13.2.1 Equation (2) (1/11)

	Value	Unit
Truck Load	16	ton/trip
Distance traveled by truck	0.25	miles/trip
Facility run-time	8,760	hours/yr
Max. annual capacity	385,440	ton/year
# of trip per year	21,900	trip/year
Total distance VMT	5,475	miles/year

GP06	PM-2.5		PM-10		PM-30	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Uncontrolled	0.0005	0.0021	0.0019	0.0084	0.0096	0.0419
Controlled[1]	0.0002	0.0010	0.0010	0.0042	0.0048	0.0210

Note:
(1) 50% control factor is applied to account for water spray
(2) The emissions are estimated based on maximum annual limestone processing equipment capacity of 40 tons per hour for 8760 hours per year.

TABLE 8: POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE FRONT END LOADERS TRAVELING ON UNPAVED ROADS
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

E = k(s/12)^a(W/3)^b — AP42,13.2.2 Equation (1a) November 2006 ed.
Eext = ((365-p)/365)*k(s/12)^a(W/3)^b — AP42,13.2.2 Equation (2) November 2006 ed.

where E = Emission factor (lb/vehicle miles traveled)
Eext = annual size-specific emission factor extrapolated for natural mitigation (lb/VMT)
k,a,b,c = constant (lb/VMT)
s = surface material silt content (%)
W = mean vehicle weight (tons)
p = number of days with at least 0.01 inches of precipitation per year

Parameter	Value			Source
	PM-2.5	PM-10	PM-30	
a	0.9	0.9	0.7	AP42, Table 13.2.2-2 (11/06)
b	0.45	0.45	0.45	AP42, Table 13.2.2-2 (11/06)
k	0.15	1.5	4.9	AP42, Table 13.2.2-2 (11/06)
s	5.1			AP42, Table 13.2.2-2 (11/06)
W	28			AES Hawaii, Inc.
p	95			WRCC (see Appendix C)

	PM-2.5	PM-10	PM-30
Emission Factor (lb/VMT)	0.190	1.897	7.355
Annual Size Specific Extrapolated for Natural Mitigation (lb/VMT)	0.140	1.404	5.441

	Value	Unit
Production Capacity	44	tph
Facility run-time	8760	hours/yr
Loader load	13	ton/trip
Distance traveled by truck	0.02	miles/trip
Max. annual capacity	385,440	ton/year
# of trip per year	26,954	trip/year
Total distance VMT	539	miles/year

GP06	PM-2.5		PM-10		PM-30	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Uncontrolled	0.009	0.038	0.086	0.378	0.335	1.466
Controlled(1)	0.004	0.019	0.043	0.189	0.167	0.733

Note:
(1) 50% control factor is applied to account for water spray

TABLE 9: POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE HANDLING
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Operating hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum capacity	44	tons/hour	CSP No. 0087-02-C, Attachment IIC, Section A.1
Production	385,440	tons/year	Operating hours x Maximum capacity

Activity	No. of Equipment	Emission Factor			Source
		TSP	PM-10	PM-2.5	
		lb/ton	lb/ton	lb/ton	
Truck Unloading	2	0.0003	0.0001	0.0001	EPA AP-42, Table 11.19.2-2 08/04 Edition
Conveyor Transfer Point	1	0.003	0.0011	0.0011	
Pulverizer with Fabric Filter Control	1	0.0054	0.0024	0.0024	
Limestone Storage Hopper Loading	1	0.0048	0.0028	0.0028	EPA AP-42, Table 11.12-2 06/06 Edition - Revised January 2012

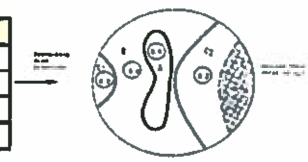
Activity	Uncontrolled Emission						Controlled Emission						
	TSP		PM-10		PM-2.5		Control Efficiency	TSP		PM-10		PM-2.5	
	lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year		lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year
Truck Unloading	0.024	0.10512	0.0088	0.038544	0.0088	0.039	50%	0.012	0.053	0.004	0.019	0.004	0.019
Conveyor Transfer Point	0.132	0.57816	0.0484	0.211992	0.0484	0.212	70%	0.040	0.173	0.015	0.064	0.015	0.064
Pulverizer with Fabric Filter Control	0.2376	1.040688	0.1056	0.462528	0.1056	0.463	99%	0.002	0.010	0.001	0.005	0.001	0.005
Limestone Storage Hopper Loading	0.2112	0.925056	0.1232	0.539616	0.1232	0.540	99%	0.002	0.009	0.001	0.005	0.001	0.005

NOTE:
Control efficiency of 50% is applied to account for water application
Conservatively assumed PM2.5 = PM10
For Truck unloading, TSP was based on PM10 and the ratio of TSP to PM10 for Conveyor point transfer.

TABLE 10: POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE STORAGE PILE
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Diameter stockpile	156.25	ft	AES Hawaii
Radius stockpile	78.125	ft	AES Hawaii
Height stockpile	10	ft	AES Hawaii
Weight/pile	25,000	tons	AES Hawaii
Bulk density	26.0655	lb/ft^3	AES Hawaii
Total exposed area (2 stockpiles)	38662.4	ft^2	AES Hawaii
Threshold friction velocity	0.55	m/s	AP42 Table 13.2.5.2 11/06 Edition
N	365		Assume daily disturbance

Pile Area	Us/Ur[1]	%	Area	Units
A	0.9	12	4,639	ft^2
B	0.6	48	18,558	ft^2
C	0.2	40	15,465	ft^2
Total			38,662	ft^2



Feb 2015 [2]					
Day	Wind speed, Ur		Friction Velocities (U*) =0.1Us		
	miles/hr	m/s	0.2	0.6	0.9
1	13	5.812	0.116	0.349	0.523
2	21	9.388	0.188	**0.563**	**0.845**
3	23	10.282	0.206	**0.617**	**0.925**
4	22	9.835	0.197	**0.590**	**0.885**
5	24	10.729	0.215	**0.644**	**0.966**
6	21	9.388	0.188	**0.563**	**0.845**
7	13	5.812	0.116	0.349	0.523
8	13	5.812	0.116	0.349	0.523
9	18	8.047	0.161	0.483	**0.724**
10	25	11.176	0.224	**0.671**	**1.006**
11	21	9.388	0.188	**0.563**	**0.845**
12	10	4.470	0.089	0.268	0.402
13	21	9.388	0.188	**0.563**	**0.845**
14	30	13.411	0.268	**0.805**	**1.207**
15	9	4.023	0.080	0.241	0.362
16	8	3.576	0.072	0.215	0.322
17	9	4.023	0.080	0.241	0.362
18	12	5.364	0.107	0.322	0.483
19	14	6.259	0.125	0.376	**0.563**
20	8	3.576	0.072	0.215	0.322
21	12	5.364	0.107	0.322	0.483
22	13	5.812	0.116	0.349	0.523
23	13	5.812	0.116	0.349	0.523
24	10	4.470	0.089	0.268	0.402
25	10	4.470	0.089	0.268	0.402
26	14	6.259	0.125	0.376	**0.563**
27	10	4.470	0.089	0.268	0.402
28	12	5.364	0.107	0.322	0.483

NOTES:

(1)Us/Ur is the ratio of surface wind speed to approach wind speed

(2)February 2015 data was chosen to represent fastest wind speed during the year based on monthly average speeds in Appendix C.

Potential emission calculation above is performed based on guidance provided by EPA AP42 Section 13.2.5 November 2006 edition

(3)Control factor of 50% is applied to account for water application

(4) Aerodynamic Particle Size Multipliers For AP 42 13.2.5-2 Equation 2 November 2006 edition

(5) Numbers in bold used in emission calculations, when wind speeds on a given day exceed frictional velocities for any pile (A, B, or C).

Pile	Day	U*>0.54	U*-0.55	Potential erosion(P)	Pile Surface area	Emission = k*P*A	
				(g/m2)	m2	gr	tons
B	2	0.563	0.013	0.34	1724.97	590	0.00065
B	3	0.617	0.066915	1.93	1724.97	3,334	0.00367
B	4	0.590	0.040093	1.10	1724.97	1,890	0.00208
B	5	0.644	0.093738	2.85	1724.97	4,921	0.00542
B	6	0.563	0.01327	0.34	1724.97	590	0.00065
B	10	0.671	0.12056	3.86	1724.97	6,653	0.00733
B	11	0.563	0.01327	0.34	1724.97	590	0.00065
B	13	0.563	0.01327	0.34	1724.97	590	0.00065
B	14	0.805	0.254672	10.13	1724.97	17,471	0.01926
A	2	0.845	0.294906	12.42	431.24	5,355	0.00590
A	3	0.925	0.375373	17.56	431.24	7,571	0.00835
A	4	0.885	0.335	14.89	431.24	6,422	0.00708
A	5	0.966	0.416	20.41	431.24	8,801	0.00970
A	6	0.845	0.295	12.42	431.24	5,355	0.00590
A	9	0.724	0.174	6.12	431.24	2,637	0.00291
A	10	1.006	0.456	23.45	431.24	10,112	0.01115
A	11	0.845	0.295	12.42	431.24	5,355	0.00590
A	13	0.845	0.295	12.42	431.24	5,355	0.00590
A	14	1.207	0.657	41.46	431.24	17,880	0.01971
A	19	0.563	0.013	0.34	431.24	147	0.00016
A	26	0.563	0.013	0.34	431.24	147	0.00016
		Total PM Emission per day				Uncontrolled	0.004400009
		Total PM Emissions per year				Uncontrolled	1.606003139
		Total PM Emissions per year(Controlled)[3]				Controlled[3]	0.803001569
		PM 10 Emissions per year (50% of total PM[4])				Uncontrolled	0.803001569
						Controlled[3]	0.401500785
		PM 2.5 Emissions per year (7.5% of total PM[4])				Uncontrolled	0.120450235
						Controlled[3]	0.060225118

Pounds Per hour		lb/hr
Total PM Emissions per hour	Uncontrolled	0.000183334
	Controlled[3]	9.16668E-05
PM 10 Emissions per hour (50% of total PM[4])	Uncontrolled	9.16668E-05
	Controlled[3]	4.58334E-05
PM 2.5 Emissions per hour (7.5% of total PM[4])	Uncontrolled	1.375E-05
	Controlled[3]	6.87501E-06

TABLE 11: POTENTIAL METALS EMISSIONS CALCULATION FROM LIMESTONE PROCESSING
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

Input	lb/hour	ton/year
Total Controlled PM Emissions from Limestone Processing	0.228	1.803

Metals	Lab Analytical Results 11/8/2000	Potential Emissions*		
	mg/kg	lb/hr	tons/year	HAP?
Antimony	0.34	7.76E-08	6.13E-07	Yes
Arsenic	3.00	6.85E-07	5.41E-06	Yes
Barium	4.00	9.13E-07	7.21E-06	No
Beryllium	0.10	2.28E-08	1.80E-07	Yes
Cadmium	0.13	2.97E-08	2.34E-07	Yes
Chromium	6.00	1.37E-06	1.08E-05	Yes
Cobalt	2.10	4.80E-07	3.79E-06	Yes
Copper	4.00	9.13E-07	7.21E-06	No
Fluorine	2.30	5.25E-07	4.15E-06	No
Lead	2.00	4.57E-07	3.61E-06	Yes
Manganese	58.00	1.32E-05	1.05E-04	Yes
Mercury	0.05	1.14E-08	9.01E-08	Yes
Molybdenum	0.70	1.60E-07	1.26E-06	No
Nickel	7.00	1.60E-06	1.26E-05	Yes
Selenium	0.40	9.13E-08	7.21E-07	Yes
Silver	0.67	1.53E-07	1.21E-06	No
Vanadium	6.00	1.37E-06	1.08E-05	No
Zinc	20.00	4.57E-06	3.61E-05	No

NOTE:
* - Estimated potential emissions for metals in fugitive PM emissions.

TABLE 12. POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE DRYER FIRED WITH NO. 2 FUEL OIL
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Dryer heat capacity	4.75	MMBtu/hr	CSP No. 0087-02-C, Attachment IIC, Section A.1.b for Dryer 1A and 1B
Fuel oil #2 heat value	140,000	Btu/gal	AP 42 Volume 1, 5th edition, Appendix A
Fuel oil #2 consumption	34	gal/hr	Dryer heat capacity / Fuel oil #2 heat value
Sulfur content in fuel oil #2	0.5	% S by wt	CSP No. 0087-02-C, Attachment IIC, Section C.4.a (for fuel oil)
Fuel oil #2 hours of operation	8,760	hr/yr	24 hours per day, 365 days per year

CAS	Contaminants	Class	Emission Factor		Uncontrolled Emission		Control	Controlled Emission		Source
			Value	Unit	lb/hr	Ton/yr	Efficiency	lb/hr	Ton/yr	
SOX	SO2	SOX, CAP	1425	lb/1000 gal	2.41	10.55	0%	2.41	10.55	AP-42, Table 1.3-1. 5/10 Edition
SOX	SO3	SOX, CAP	5.75	lb/1000 gal	0.10	0.42	0%	0.10	0.42	
NOX	NOx	NOX, CAP	24	lb/1000 gal	0.81	3.57	0%	0.81	3.57	
630080	CO	CAP	5	lb/1000 gal	0.17	0.74	0%	0.17	0.74	
PM	PM Total	PM, CAP	3.3	lb/1000 gal	0.11	0.4904	99%	0.0011	0.0049	Sum of subcategories
PM	PM10 Total	PM, CAP	51.3	lb/1000 gal	0.08	0.3418	99%	0.0008	0.0034	
PM	PM2.5 Total	PM, CAP	13.3	lb/1000 gal	0.05	0.2289	99%	0.0005	0.0023	
PM	PM- Filterable	PM, CAP	2	lb/1000 gal	0.07	0.2972	99%	0.0007	0.0030	AP-42, Table 1.3-1. 5/10 Edition
PM	PM10 - Filterable	PM, CAP	50	%	0.03	0.1486	99%	0.0003	0.0015	AP-42, Table 1.3-6. 5/10 Edition
PM	PM2.5 - Filterable	PM, CAP	12	%	0.01	0.0357	99%	0.0001	0.0004	
PM	PM- Condensable	PM, CAP	1.3	lb/1000 gal	0.04	0.1932	99%	0.0004	0.0019	AP-42, Table 1.3-2. 5/10 Edition
TOC	TOC	TOC	0.252	lb/1000 gal	0.01	0.0374	0%	0.01	0.0374	AP-42, Table 1.3-3. 5/10 Edition
VOC	VOC (NMTOC)	VOC, CAP	0.2	lb/1000 gal	0.01	0.0297	0%	0.01	0.0297	
124389	CO2	GHG	22300	lb/1000 gal	756.61	3,314	0%	756.61	3,314	AP-42, Table 1.3-12. 5/10 Edition
74828	Methane	GHG	0.052	lb/1000 gal	1.76E-03	7.73E-03	0%	1.76E-03	7.73E-03	AP-42, Table 1.3-3. 5/10 Edition
10024972	N2O	GHG	0.26	lb/1000 gal	8.82E-03	3.86E-02	0%	8.82E-03	3.86E-02	AP-42, Table 1.3-8. 5/10 Edition
71556	1,1,1-Trichloroethane	HAP	2.36E-04	lb/1000 gal	8.01E-06	3.51E-05	0%	8.01E-06	3.51E-05	AP-42, Table 1.3-9. 5/10 Edition
71432	Benzene	HAP	2.14E-04	lb/1000 gal	7.26E-06	3.18E-05	0%	7.26E-06	3.18E-05	
100414	Ethylbenzene	HAP	6.36E-05	lb/1000 gal	2.16E-06	9.45E-06	0%	2.16E-06	9.45E-06	
50000	Formaldehyde	HAP	3.30E-02	lb/1000 gal	1.12E-03	4.90E-03	0%	1.12E-03	4.90E-03	
95476	o-Xylene	HAP	1.09E-04	lb/1000 gal	3.70E-06	1.62E-05	0%	3.70E-06	1.62E-05	
108883	Toluene	HAP	6.20E-03	lb/1000 gal	2.10E-04	9.21E-04	0%	2.10E-04	9.21E-04	
7440382	Arsenic	Metals, HAP	4	lb/10^12 Btu	1.90E-05	8.32E-05	99%	1.90E-07	8.32E-07	AP-42, Table 1.3-10. 5/10 Edition
7440417	Beryllium	Metals, HAP	3	lb/10^12 Btu	1.43E-05	6.24E-05	99%	1.43E-07	6.24E-07	
7440439	Cadmium	Metals, HAP	3	lb/10^12 Btu	1.43E-05	6.24E-05	99%	1.43E-07	6.24E-07	
7440473	Chromium	Metals, HAP	3	lb/10^12 Btu	1.43E-05	6.24E-05	99%	1.43E-07	6.24E-07	
7439921	Lead	Metals, HAP	9	lb/10^12 Btu	4.28E-05	1.87E-04	99%	4.28E-07	1.87E-06	
7439965	Manganese	Metals, HAP	6	lb/10^12 Btu	2.85E-05	1.25E-04	99%	2.85E-07	1.25E-06	
7439976	Mercury	Metals, HAP	3	lb/10^12 Btu	1.43E-05	6.24E-05	99%	1.43E-07	6.24E-07	
7440020	Nickel	Metals, HAP	3	lb/10^12 Btu	1.43E-05	6.24E-05	99%	1.43E-07	6.24E-07	
7782492	Selenium	Metals, HAP	15	lb/10^12 Btu	7.13E-05	3.12E-04	99%	7.13E-07	3.12E-06	
83329	Acenaphthene	PAH, HAP	2.11E-05	lb/1000 gal	7.16E-07	3.14E-06	0%	7.16E-07	3.14E-06	AP-42, Table 1.3-9. 5/10 Edition
208968	Acenaphthylene	PAH, HAP	2.53E-07	lb/1000 gal	8.58E-09	3.76E-08	0%	8.58E-09	3.76E-08	
120127	Anthracene	PAH, HAP	1.22E-06	lb/1000 gal	4.14E-08	1.81E-07	0%	4.14E-08	1.81E-07	
56553	Benz(a)anthracene	PAH, HAP	4.01E-06	lb/1000 gal	1.36E-07	5.96E-07	0%	1.36E-07	5.96E-07	
205992; 207089	Benzo(b,k)fluoranthene	PAH, HAP	1.48E-06	lb/1000 gal	5.02E-08	2.20E-07	0%	5.02E-08	2.20E-07	
191242	Benzo(g,h,i)perylene	PAH, HAP	2.26E-06	lb/1000 gal	7.67E-08	3.36E-07	0%	7.67E-08	3.36E-07	
218019	Chrysene	PAH, HAP	2.38E-06	lb/1000 gal	8.08E-08	3.54E-07	0%	8.08E-08	3.54E-07	
226368	Dibenzo(a,h)anthracene	PAH, HAP	1.67E-06	lb/1000 gal	5.67E-08	2.48E-07	0%	5.67E-08	2.48E-07	
206440	Fluoranthene	PAH, HAP	4.84E-06	lb/1000 gal	1.64E-07	7.19E-07	0%	1.64E-07	7.19E-07	
86737	Fluorene	PAH, HAP	4.47E-06	lb/1000 gal	1.52E-07	6.64E-07	0%	1.52E-07	6.64E-07	
193395	Indeno(1,2,3,c,d)pyrene	PAH, HAP	2.14E-06	lb/1000 gal	7.26E-08	3.18E-07	0%	7.26E-08	3.18E-07	
91203	Naphthalene	PAH, HAP	1.13E-03	lb/1000 gal	3.83E-05	1.68E-04	0%	3.83E-05	1.68E-04	
85018	Phenanthrene	PAH, HAP	1.05E-05	lb/1000 gal	3.56E-07	1.56E-06	0%	3.56E-07	1.56E-06	
129000	Pyrene	PAH, HAP	4.25E-06	lb/1000 gal	1.44E-07	6.32E-07	0%	1.44E-07	6.32E-07	
POM	Polycyclic organic matter (POM)	POM, HAP	2.11E-03	lb/1000 gal	7.16E-05	3.13E-04	0%	7.16E-05	3.13E-04	AP-42, Table 1.3-8. 5/10 Edition value of 0.0033 lb/1000 gal minus PAH's listed in AP-42, Table 1.3-9
3268-87-9	OCDD	Dioxin/Furan	3.10E-09	lb/1000 gal	1.05E-10	4.61E-10	0%	1.05E-10	4.61E-10	AP-42, Table 1.3-9. 5/10 Edition

NOTE:
Control efficiency of 99% is applied to account for the use of baghouse.

TABLE 13. POTENTIAL EMISSIONS CALCULATION FROM LIMESTONE DRYER FIRED WITH SPECIFICATION USED OIL
Limestone Processing
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Dryer heat capacity	4.75	MMBtu/hr	CSP No. 0087-02-C, Attachment IIC, Section A.1.b
Annual spec used oil consumption	250,000	gal/yr	CSP No. 0087-02-C, Attachment IIC, Section C.b.1
Sulfur content in spec used oil	0.5	% S by wt	Data from AES
Chlorine content in spec used oil	0.047	% Cl by wt	Spec Oil Data from supplier in 2012 to AES. Halogens Average = 470ppm; Conservatively assume all Halogens could be chlorine
Lead content in spec used oil	0.0014	% Pb by wt	Spec Oil Data from supplier in 2012 to AES. Average = 8.5ppm, Max = 14ppm
Ash content in spec used oil	0.76	% Ash by wt	Spec Oil Data from supplier in 2012 to AES. Average = 0.53%, Max = 0.76%
Spec used oil hours of operation	8,760	hr/yr	24 hours per day, 365 days per year

CAS	Contaminants	Class	Emission Factor		Uncontrolled Emission		Control	Controlled Emission		Source
			Value	Unit	lb/hr	Ton/yr	Efficiency	lb/hr	Ton/yr	
SOX	SO2	SOX, CAP	1475*.96	lb/1000 gal	2.01	8.82	0%	2.01	8.82	AP-42, Table 1.11-2. 10/96 Edition. SOX split into SO2 and SO3 based on profile used for Fuel oil #2 of 96% as SO2 and 4% as SO3
SOX	SO3	SOX, CAP	1475*.04	lb/1000 gal	0.08	0.37	0%	0.08	0.37	
NOX	NOx	NOX, CAP	19	lb/1000 gal	0.54	2.38	0%	0.54	2.38	
630080	CO	CAP	5	lb/1000 gal	0.14	0.63	0%	0.14	0.63	
PM	PM Total	PM, CAP	64*wt% ash in oil	lb/1000 gal	1.39	6.08	99%	0.01	0.06	AP-42, Table 1.11-1. 10/96 Edition
PM	PM10 Total	PM, CAP	51*wt% ash in oil	lb/1000 gal	1.11	4.85	99%	0.01	0.05	
PM	PM2.5 Total	PM, CAP	47%	of PM Total	0.65	2.84	99%	0.01	0.03	Split into based on profile used for Fuel oil #2.
PM	PM- Filterable	PM, CAP	61%	of PM Total	0.84	3.68	99%	0.01	0.04	
PM	PM10 - Filterable	PM, CAP	30%	of PM Total	0.42	1.84	99%	0.00	0.02	
PM	PM2.5 - Filterable	PM, CAP	7%	of PM Total	0.10	0.44	99%	0.00	0.00	
PM	PM- Condensable	PM, CAP	39%	of PM Total	0.55	2.40	99%	0.01	0.02	
TOC	TOC	TOC	1	lb/1000 gal	0.03	0.13	0%	0.03	0.13	AP-42, Table 1.11-3. 10/96 Edition
VOC	VOC	VOC, CAP	0.2	lb/1000 gal	0.01	0.03	0%	0.01	0.03	AP-42, Table 1.3-3. 5/10 Edition (Fuel Oil No. 2 as Proxy)
124389	CO2	GHG	22000	lb/1000 gal	628	2,750	0%	628	2,750	AP-42, Table 1.11-3. 10/96 Edition
74828	Methane	GHG	0.052	lb/1000 gal	1.48E-03	6.50E-03	0%	1.48E-03	6.50E-03	AP-42, Table 1.3-3. 5/10 Edition (Fuel Oil No. 2 as Proxy)
10024972	N2O	GHG	0.26	lb/1000 gal	7.42E-03	3.25E-02	0%	7.42E-03	3.25E-02	AP-42, Table 1.3-8. 5/10 Edition (Fuel Oil No. 2 as Proxy)
7647010	Hydrogen Chloride	HAP	66*wt% Cl in oil	lb/1000 gal	8.85E-02	3.88E-01	0%	8.85E-02	3.88E-01	AP-42, Table 1.11-3. 10/96 Edition
7440382	Arsenic	Metals, HAP	1.10E-01	lb/1000 gal	3.14E-03	1.38E-02	99%	3.14E-05	1.38E-04	AP-42, Table 1.11-4. 10/96 Edition
7440439	Cadmium	Metals, HAP	9.30E-03	lb/1000 gal	2.65E-04	1.16E-03	99%	2.65E-06	1.16E-05	
7440473	Chromium	Metals, HAP	2.00E-02	lb/1000 gal	5.71E-04	2.50E-03	99%	5.71E-06	2.50E-05	
7440484	Cobalt	Metals, HAP	2.10E-04	lb/1000 gal	5.99E-06	2.63E-05	99%	5.99E-08	2.63E-07	
7439921	Lead	Metals, HAP	55*wt% lead in oil	lb/1000 gal	2.20E-03	9.63E-03	99%	2.20E-05	9.63E-05	AP-42, Table 1.11-1. 10/96 Edition
7439965	Manganese	Metals, HAP	6.80E-02	lb/1000 gal	1.94E-03	8.50E-03	99%	1.94E-05	8.50E-05	AP-42, Table 1.11-4. 10/96 Edition
7440020	Nickel	Metals, HAP	1.10E-02	lb/1000 gal	3.14E-04	1.38E-03	99%	3.14E-06	1.38E-05	AP-42, Table 1.11-4. 10/96 Edition

NOTE:
Control efficiency of 99% is applied to account for the use of baghouse.

TABLE 14: POTENTIAL EMISSION CALCULATION FROM STORAGE TANK OPERATION

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	AES	
City:	Honolulu	
State:	Hawaii	
Company:	Cogeneration Plant	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	AES Cogeneration Plant	
Tank Dimensions		
Shell Height (ft):		18.00
Diameter (ft):		24.00
Liquid Height (ft) :		14.40
Avg. Liquid Height (ft):		12.00
Volume (gallons):		48,731.31
Turnovers:		15.86
Net Throughput(gal/yr):		772,840.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	White/White	
Shell Condition	Good	
Roof Color/Shade:	White/White	
Roof Condition:	Good	
Roof Characteristics		
Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Honolulu, Hawaii (Avg Atmospheric Pressure = 14.73 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

AES - Vertical Fixed Roof Tank
Honolulu, Hawaii

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight
Distillate fuel oil no. 2	All	79.53	74.90	84.16	77.24	0.0119	0.0105	0.0137	130.0000			188.00

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

AES - Vertical Fixed Roof Tank
Honolulu, Hawaii

Annual Emission Calcaulations	
Standing Losses (lb):	8.3519
Vapor Space Volume (cu ft):	2,827.4334
Vapor Density (lb/cu ft):	0.0003
Vapor Space Expansion Factor:	0.0305
Vented Vapor Saturation Factor:	0.9961
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	2,827.4334
Tank Diameter (ft):	24.0000
Vapor Space Outage (ft):	6.2500
Tank Shell Height (ft):	18.0000
Average Liquid Height (ft):	12.0000
Roof Outage (ft):	0.2500
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.2500
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0625
Shell Radius (ft):	12.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0003
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0119
Daily Avg. Liquid Surface Temp. (deg. R):	539.2010
Daily Average Ambient Temp. (deg. F):	77.2208
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	536.9108
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,711.8303
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0305
Daily Vapor Temperature Range (deg. R):	18.5223
Daily Vapor Pressure Range (psia):	0.0032
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0119
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0105
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0137
Daily Avg. Liquid Surface Temp. (deg R):	539.2010
Daily Min. Liquid Surface Temp. (deg R):	534.5704
Daily Max. Liquid Surface Temp. (deg R):	543.8316
Daily Ambient Temp. Range (deg. R):	14.4083
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9961
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0119
Vapor Space Outage (ft):	6.2500
Working Losses (lb):	28.3689
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0119
Annual Net Throughput (gal/yr.):	772,840.0000
Annual Turnovers:	15.8592
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	48,731.3063
Maximum Liquid Height (ft):	14.4000
Tank Diameter (ft):	24.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	36.7208

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

AES - Vertical Fixed Roof Tank
Honolulu, Hawaii

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	28.37	8.35	36.72

Table 15. Potential Emissions Calculation from CFB Boilers Fired with Coal
(including coal mixed with Tire Derived Fuel (TDF), and/or Spent Activated Carbon)
CFB Boilers
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Coal heat value	10,180	Btu/lb	Weighted average HHV in coal burned in 2017
Combined maximum feedrate Coal and TDF	215,000	lb/hr	CSP No. 0087-02-C, Attachment IIA, Section C.3.a
Maximum hourly Coal and TDF consumption	107.5	ton/hr	CSP No. 0087-02-C, Attachment IIA, Section C.3.a
Maximum Hourly firing assuming 100% Coal	2,188.7	MMBtu/hr	CSP No. 0087-02-C, Attachment IIA, Section C.3.a and HHV
Maximum annual coal usage	941,700	tons/yr	AES Hawaii, Inc.
Coal hours of operation	8,760	hr/yr	24 hours per day, 365 days per year

CAS		Contaminants	Class	Emission Factor		Controlled Emission		Source
				Value	Unit	lb/hr	Ton/yr	
SOX	Boiler A CEMS limit for SO2 & Recent Stack Test Results (Not used for Potential-to-Emit determination)	SO2	SOX, CAP	322.5	lb/hr	165	723	CEMS ensures compliance with existing limit of 645 lb/hr for total of both boilers. Prior to that, a sulfur content of 1.5% in coal was in place and a factor of 138 lb/hr rate was used based on AES Hawaii, Inc. August 2006 Stack Test Result.
NOX		NOx	NOX, CAP	107.4	lb/hr	103.00	451.14	AES Hawaii, Inc. June 2011 Stack Test Result
630080		CO	CAP	28.3	lb/hr	28.30	123.95	
PM		PM10	PM, CAP	0.82	lb/hr	4.42	19.36	
VOC		VOC	VOC, CAP	7.61	lb/hr	0.60	2.64	
		Fluorides		0.032	lb/hr	0.01	0.06	
7664939		Sulfuric Acid Mist		0.25	lb/hr	4.10	17.96	
7440417		Beryllium		9.87E-05	lb/hr	1.82E-05	7.97E-05	
7439921		Lead	Metals, HAP	9.87E-05	lb/hr	1.23E-03	5.39E-03	
7439976		Mercury	Metals, HAP	2.35E-04	lb/hr	3.21E-05	1.41E-04	
SOX	Boiler B CEMS limit for SO2 & Recent Stack Test Results (Not used for Potential-to-Emit determination)	SO2	SOX, CAP	322.5	lb/hr	162	710	CEMS ensures compliance with existing limit of 645 lb/hr for total of both boilers. Prior to that, a sulfur content of 1.5% in coal was in place and a factor of 138 lb/hr rate was used based on AES Hawaii, Inc. August 2006 Stack Test Result.
NOX		NOx	NOX, CAP	104.1	lb/hr	101.00	442.38	AES Hawaii, Inc. June 2011 Stack Test Result
630080		CO	CAP	39.6	lb/hr	76.30	334.19	
PM		PM10	PM, CAP	0.90	lb/hr	10.70	46.87	
VOC		VOC	VOC, CAP	7.24	lb/hr	0.64	2.80	
		Fluorides		0.036	lb/hr	0.02	0.10	
7664939		Sulfuric Acid Mist		0.46	lb/hr	0.12	0.51	
7440417		Beryllium		8.27E-05	lb/hr	7.56E-05	3.31E-04	
7439921		Lead	Metals, HAP	8.27E-05	lb/hr	8.05E-04	3.53E-03	
7439976		Mercury	Metals, HAP	1.02E-05	lb/hr	3.57E-07	1.56E-06	
SOX	Boilers A&B Combined (Used for Potential-to-Emit determination)	SO2	SOX, CAP	645.0	lb/hr	645	2,825	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10
NOX		NOx	NOX, CAP	236.5	lb/hr	236.50	1,035.87	
630080		CO	CAP	408.4	lb/hr	408.40	1,788.79	
PM		PM Total	PM, CAP	32.2	lb/hr	32.20	141.04	
PM		PM10 Total	PM, CAP	32.2	lb/hr	32.20	141.04	
PM		PM2.5 Total	PM, CAP	26%	% of PM total	8.37	36.67	Ratio of PM2.5 to PM total from AP-42, Table 1.1-9. 9/98 Edition for spreader stoker (footnoted in AP42 Table 1.1-4 as most representative for FBC).
PM		PM- Filterable	PM, CAP	32.0	lb/hr	32.00	140.17	Calculated (PM Total - PM Condensable)
PM		PM10 - Filterable	PM, CAP	32.0	lb/hr	32.00	140.17	Calculated (PM10 Total - PM Condensable)
PM		PM2.5 - Filterable	PM, CAP	8.2	lb/hr	8.17	35.80	Calculated (PM2.5 Total - PM Condensable)
PM		PM- Condensable	PM, CAP	0.0062	Ratio of CPM to PM	0.20	0.87	Relative (uncontrolled) Condensable PM from AP42 Table 1.1-5 9/98 (0.02 lb/MMBtu) multiplied by heat content of coal; compared relative (uncontrolled total PM value of 66 lb/ton from AP-42, Table 1.1-9. 9/98 Edition for spreader stoker (footnoted in AP42 Table 1.1-4 as most representative for FBC).
VOC		VOC	VOC, CAP	32.2	lb/hr	32.20	141.04	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10
		Fluorides		0.2	lb/hr	0.20	0.88	
7664939		Sulfuric Acid Mist		4.10	lb/hr	4.10	17.96	
7440417		Beryllium		0.067	lb/hr	0.07	0.29	
7439921		Lead	Metals, HAP	5.7	lb/hr	5.70	24.97	
7439976		Mercury	Metals, HAP	0.17	lb/hr	0.17	0.74	
TOC		TNMOC	TOC	0.05	lb/ton	5.38	23.54	AP-42, Table 1.1-19. 9/98 Edition, Fluidized Bed Boiler

CAS	Pollutant	Type	Factor	Units			Source
124389	CO2	GHG	6,250	lb/ton	671,875	2,942,813	AP-42, Table 1.1-20. 9/98 Edition
74828	Methane	GHG	0.06	lb/ton	6.45	28.25	AP-42, Table 1.1-19. 9/98 Edition, Fluidized Bed Boiler
10024972	N2O	GHG	3.50	lb/ton	376.25	1,647.98	
71556	1,1,1-Trichloroethane	HAP	2.00E-05	lb/ton	2.15E-03	9.42E-03	AP-42, Table 1.1-14. 9/98 Edition, Controlled
121142	2,4-Dinitrotoluene	HAP	2.80E-07	lb/ton	3.01E-05	1.32E-04	
532274	2-Chloroacetophenone	HAP	7.00E-06	lb/ton	7.53E-04	3.30E-03	
75070	Acetaldehyde	HAP	5.70E-04	lb/ton	6.13E-02	2.68E-01	
98862	Acetophenone	HAP	1.50E-05	lb/ton	1.61E-03	7.06E-03	
107028	Acrolein	HAP	2.90E-04	lb/ton	3.12E-02	1.37E-01	
71432	Benzene	HAP	1.30E-03	lb/ton	1.40E-01	6.12E-01	
100447	Benzyl chloride	HAP	7.00E-04	lb/ton	7.53E-02	3.30E-01	
117817	Bis(2-ethylhexyl)phthalate (DEHP)	HAP	7.30E-05	lb/ton	7.85E-03	3.44E-02	
75252	Bromoform	HAP	3.90E-05	lb/ton	4.19E-03	1.84E-02	
75150	Carbon disulfide	HAP	1.30E-04	lb/ton	1.40E-02	6.12E-02	
108907	Chlorobenzene	HAP	2.20E-05	lb/ton	2.37E-03	1.04E-02	
67663	Chloroform	HAP	5.90E-05	lb/ton	6.34E-03	2.78E-02	
98828	Cumene	HAP	5.30E-06	lb/ton	5.70E-04	2.50E-03	
	Cyanide	HAP	2.50E-03	lb/ton	2.69E-01	1.18E+00	
77781	Dimethyl sulfate	HAP	4.80E-05	lb/ton	5.16E-03	2.26E-02	
100414	Ethyl benzene	HAP	9.40E-05	lb/ton	1.01E-02	4.43E-02	
75003	Ethyl chloride	HAP	4.20E-05	lb/ton	4.52E-03	1.98E-02	
106934	Ethylene dibromide	HAP	1.20E-06	lb/ton	1.29E-04	5.65E-04	
107062	Ethylene dichloride	HAP	4.00E-05	lb/ton	4.30E-03	1.88E-02	
50000	Formaldehyde	HAP	2.40E-04	lb/ton	2.58E-02	1.13E-01	
110543	Hexane	HAP	6.70E-05	lb/ton	7.20E-03	3.15E-02	
7647010	Hydrogen Chloride	HAP	4.30	lb/hr	4.30	18.83	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10
78591	Isophorone	HAP	5.80E-04	lb/ton	6.24E-02	2.73E-01	AP-42, Table 1.1-14. 9/98 Edition, Controlled
74839	Methyl bromide	HAP	1.60E-04	lb/ton	1.72E-02	7.53E-02	
74873	Methyl chloride	HAP	5.30E-04	lb/ton	5.70E-02	2.50E-01	
78933	Methyl ethyl ketone	HAP	3.90E-04	lb/ton	4.19E-02	1.84E-01	
60344	Methyl hydrazine	HAP	1.70E-04	lb/ton	1.83E-02	8.00E-02	
80626	Methyl methacrylate	HAP	2.00E-05	lb/ton	2.15E-03	9.42E-03	
1634044	Methyl tert butyl ether	HAP	3.50E-05	lb/ton	3.76E-03	1.65E-02	
75092	Methylene chloride	HAP	2.90E-04	lb/ton	3.12E-02	1.37E-01	
7440020	Nickel	HAP	2.80E-04	lb/ton	3.01E-02	1.32E-01	AP-42, Table 1.1-18. 9/98 Edition, Controlled
108952	Phenol	HAP	1.60E-05	lb/ton	1.72E-03	7.53E-03	AP-42, Table 1.1-14. 9/98 Edition, Controlled
123386	Propionaldehyde	HAP	3.80E-04	lb/ton	4.09E-02	1.79E-01	
100425	Styrene	HAP	2.50E-05	lb/ton	2.69E-03	1.18E-02	
127184	Tetrachloroethylene	HAP	4.30E-05	lb/ton	4.62E-03	2.02E-02	
108883	Toluene	HAP	2.40E-04	lb/ton	2.58E-02	1.13E-01	
108054	Vinyl acetate	HAP	7.60E-06	lb/ton	8.17E-04	3.58E-03	
1330207	Xylenes	HAP	3.70E-05	lb/ton	3.98E-03	1.74E-02	
7440360	Antimony	Metals, HAP	1.80E-05	lb/ton	1.94E-03	8.48E-03	AP-42, Table 1.1-18. 9/98 Edition, Controlled
7440382	Arsenic	Metals, HAP	4.10E-04	lb/ton	4.41E-02	1.93E-01	
7440439	Cadmium	Metals, HAP	5.10E-05	lb/ton	5.48E-03	2.40E-02	
18540299	Chromium (VI)	Metals, HAP	7.90E-05	lb/ton	8.49E-03	3.72E-02	
7440473	Chromium (other than VI)	Metals, HAP	1.81E-04	lb/ton	1.95E-02	8.52E-02	
7440484	Cobalt	Metals, HAP	1.00E-04	lb/ton	1.08E-02	4.71E-02	
7439965	Manganese	Metals, HAP	4.90E-04	lb/ton	5.27E-02	2.31E-01	
7782492	Selenium	Metals, HAP	1.30E-03	lb/ton	1.40E-01	6.12E-01	

3697243		5-Methyl chrysene	PAH, HAP	2.20E-08	lb/ton	2.37E-06	1.04E-05	AP-42, Table 1.1-13. 9/98 Edition, Controlled
83329		Acenaphthene	PAH, HAP	5.10E-07	lb/ton	5.48E-05	2.40E-04	
208968		Acenaphthylene	PAH, HAP	2.50E-07	lb/ton	2.69E-05	1.18E-04	
120127		Anthracene	PAH, HAP	2.10E-07	lb/ton	2.26E-05	9.89E-05	
56553		Benzo(a)anthracene	PAH, HAP	8.00E-08	lb/ton	8.60E-06	3.77E-05	
50328		Benzo(a)pyrene	PAH, HAP	3.80E-08	lb/ton	4.09E-06	1.79E-05	
05992; 205823; 207085		Benzo(b,j,k)fluoranthene	PAH, HAP	1.10E-07	lb/ton	1.18E-05	5.18E-05	
191242		Benzo(g,h,i)perylene	PAH, HAP	2.70E-08	lb/ton	2.90E-06	1.27E-05	
218019		Chrysene	PAH, HAP	1.00E-07	lb/ton	1.08E-05	4.71E-05	
206440		Fluoranthene	PAH, HAP	7.10E-07	lb/ton	7.63E-05	3.34E-04	
86737		Fluorene	PAH, HAP	9.10E-07	lb/ton	9.78E-05	4.28E-04	
193395		Indeno(1,2,3-cd)pyrene	PAH, HAP	6.10E-08	lb/ton	6.56E-06	2.87E-05	
91203		Naphthalene	PAH, HAP	1.30E-05	lb/ton	1.40E-03	6.12E-03	
85018		Phenanthrene	PAH, HAP	2.70E-06	lb/ton	2.90E-04	1.27E-03	
129000		Pyrene	PAH, HAP	3.30E-07	lb/ton	3.55E-05	1.55E-04	
92524		Biphenyl	PAH, HAP	1.70E-06	lb/ton	1.83E-04	8.00E-04	
POM		Polycyclic organic matter (POM)	POM, HAP	0	lb/10^{12} Btu	0.00E+00	0.00E+00	AP-42, Table 1.1-17. 9/98 (Not-detected for Non-pulverized coal). Some POM already calculated from AP-42, Table AP-42, Table 1.1-13. 9/98 Edition.
1746-01-6		2,3,7,8-TCDD	Dioxin/Furan, HAP	1.43E-11	lb/ton	1.54E-09	6.73E-09	AP-42, Table 1.1-12. 9/98 Edition, Controlled Fabric Filter
41903-57-5		Other TCDD	Dioxin/Furan, HAP	7.85E-11	lb/ton	8.44E-09	3.70E-08	
51207-31-9		2,3,7,8-TCDF	Dioxin/Furan	5.10E-11	lb/ton	5.48E-09	2.40E-08	
55722-27-5		Other TCDF	Dioxin/Furan	3.53E-10	lb/ton	3.79E-08	1.66E-07	
37871-00-4		Total HpCDD	Dioxin/Furan	8.34E-11	lb/ton	8.97E-09	3.93E-08	
38998-75-3		Total HpCDF	Dioxin/Furan	7.68E-11	lb/ton	8.26E-09	3.62E-08	
34465-4608		Total HxCDD	Dioxin/Furan	2.87E-11	lb/ton	3.09E-09	1.35E-08	
55684-94-1		Total HxCDF	Dioxin/Furan	1.92E-10	lb/ton	2.06E-08	9.04E-08	
3268-87-9		Total OCDD	Dioxin/Furan	4.16E-10	lb/ton	4.47E-08	1.96E-07	
39001-02-0		Total OCDF	Dioxin/Furan	6.63E-11	lb/ton	7.13E-09	3.12E-08	
36088-22-9		Total PeCDD	Dioxin/Furan	4.47E-11	lb/ton	4.81E-09	2.10E-08	
30402-15-4		Total PeCDF	Dioxin/Furan	3.53E-10	lb/ton	3.79E-08	1.66E-07	

TABLE 16. POTENTIAL EMISSIONS CALCULATION FROM CFB BOILERS FIRED WITH FUEL OIL

CFB Boilers

AES Hawaii, Inc.

CSP No. 0087-02-C

Parameters	Value	Unit	Source
Single boiler design heat capacity	2,150	MMBtu/hr	CSP No. 0087-02-C, Attachment IIA, Section A.1.a
Maximum annual fuel oil #2 consumption	475,000	gallons/year	AES Hawaii
Fuel oil #2 heat value	140,000	Btu/gal	AP 42 Volume 1, 5th edition, Appendix A
Fuel oil #2 annual heat capacity	66,500	MMBtu/yr	Annual fuel oil #2 consumption x fuel oil #2 heat value
Maximum hourly fuel oil #2 consumption	54.22	gallons/hr	Maximum annual fuel oil #2 consumption / 8760 hours per year
Sulfur content in fuel oil #2	0.5	% S by wt	CSP No. 0087-02-C, Attachment IIC, Section C.4.a (for fuel oil)

CAS	Contaminants	Class	Emission Factor		Uncontrolled Emission		Control	Controlled Emission		Source
			Value	Unit	lb/hr	Ton/yr	Efficiency	lb/hr	Ton/yr	
SOX	SO2	SOX, CAP	1425	lb/1000 gal	3.85	16.86	75%	0.96	4.22	
SOX	SO3	SOX, CAP	5.75	lb/1000 gal	0.15	0.68	0%	0.15	0.68	AP-42, Table 1.3-1. 5/10 Edition
NOX	NOx	NOX, CAP	24	lb/1000 gal	1.30	5.70	70%	0.39	1.71	
630080	CO	CAP	5	lb/1000 gal	0.27	1.19	0%	0.27	1.19	
PM	PM Total	PM, CAP	3.3	lb/1000 gal	0.18	0.78	99%	0.0018	0.0078	
PM	PM10 Total	PM, CAP	51.3	lb/1000 gal	0.12	0.55	99%	0.0012	0.0055	Sum of subcategories
PM	PM2.5 Total	PM, CAP	13.3	lb/1000 gal	0.08	0.37	99%	0.0008	0.0037	
PM	PM- Filterable	PM, CAP	2	lb/1000 gal	0.11	0.48	99%	0.0011	0.0048	AP-42, Table 1.3-1. 5/10 Edition
PM	PM10 - Filterable	PM, CAP	50	%	0.05	0.24	99%	0.0005	0.0024	AP-42, Table 1.3-6. 5/10 Edition
PM	PM2.5 - Filterable	PM, CAP	12	%	0.01	0.06	99%	0.0001	0.0006	
PM	PM- Condensable	PM, CAP	1.3	lb/1000 gal	0.07	0.31	99%	0.0007	0.0031	AP-42, Table 1.3-2. 5/10 Edition
						0.00				
TOC	TOC	TOC	0.252	lb/1000 gal	0.01	0.06	0%	0.014	0.0599	AP-42, Table 1.3-3. 5/10 Edition
VOC	VOC (NMTOC)	VOC, CAP	0.2	lb/1000 gal	0.01	0.05	0%	0.011	0.0475	
124389	CO2	GHG	22300	lb/1000 gal	1,209	5,296	0%	1,209	5,296	AP-42, Table 1.3-12. 5/10 Edition
74828	Methane	GHG	0.052	lb/1000 gal	2.82E-03	1.24E-02	0%	2.82E-03	1.24E-02	AP-42, Table 1.3-3. 5/10 Edition
10024972	N2O	GHG	0.26	lb/1000 gal	1.41E-02	6.18E-02	0%	1.41E-02	6.18E-02	AP-42, Table 1.3-8. 5/10 Edition
71556	1,1,1-Trichloroethane	HAP	2.36E-04	lb/1000 gal	1.28E-05	5.61E-05	0%	1.28E-05	5.61E-05	
71432	Benzene	HAP	2.14E-04	lb/1000 gal	1.16E-05	5.08E-05	0%	1.16E-05	5.08E-05	
100414	Ethylbenzene	HAP	6.36E-05	lb/1000 gal	3.45E-06	1.51E-05	0%	3.45E-06	1.51E-05	AP-42, Table 1.3-9. 5/10 Edition
50000	Formaldehyde	HAP	3.30E-02	lb/1000 gal	1.79E-03	7.84E-03	0%	1.79E-03	7.84E-03	
95476	o-Xylene	HAP	1.09E-04	lb/1000 gal	5.91E-06	2.59E-05	0%	5.91E-06	2.59E-05	
108883	Toluene	HAP	6.20E-03	lb/1000 gal	3.36E-04	1.47E-03	0%	3.36E-04	1.47E-03	
7440382	Arsenic	Metals, HAP	4	lb/10^{12} Btu	1.72E-02	1.33E-04	99%	1.72E-04	1.33E-06	
7440417	Beryllium	Metals, HAP	3	lb/10^{12} Btu	1.29E-02	9.98E-05	99%	1.29E-04	9.98E-07	
7440439	Cadmium	Metals, HAP	3	lb/10^{12} Btu	1.29E-02	9.98E-05	99%	1.29E-04	9.98E-07	
7440473	Chromium	Metals, HAP	3	lb/10^{12} Btu	1.29E-02	9.98E-05	99%	1.29E-04	9.98E-07	
7439921	Lead	Metals, HAP	9	lb/10^{12} Btu	3.87E-02	2.99E-04	99%	3.87E-04	2.99E-06	AP-42, Table 1.3-10. 5/10 Edition
7439965	Manganese	Metals, HAP	6	lb/10^{12} Btu	2.58E-02	2.00E-04	99%	2.58E-04	2.00E-06	
7439976	Mercury	Metals, HAP	3	lb/10^{12} Btu	1.29E-02	9.98E-05	99%	1.29E-04	9.98E-07	
7440020	Nickel	Metals, HAP	3	lb/10^{12} Btu	1.29E-02	9.98E-05	99%	1.29E-04	9.98E-07	
7782492	Selenium	Metals, HAP	15	lb/10^{12} Btu	6.45E-02	4.99E-04	99%	6.45E-04	4.99E-06	
83329	Acenaphthene	PAH, HAP	2.11E-05	lb/1000 gal	1.14E-06	5.01E-06	0%	1.14E-06	5.01E-06	
208968	Acenaphthylene	PAH, HAP	2.53E-07	lb/1000 gal	1.37E-08	6.01E-08	0%	1.37E-08	6.01E-08	
120127	Anthracene	PAH, HAP	1.22E-06	lb/1000 gal	6.62E-08	2.90E-07	0%	6.62E-08	2.90E-07	
56553	Benz(a)anthracene	PAH, HAP	4.01E-06	lb/1000 gal	2.17E-07	9.52E-07	0%	2.17E-07	9.52E-07	
205992; 207089	Benzo(b,k)fluoranthene	PAH, HAP	1.48E-06	lb/1000 gal	8.03E-08	3.52E-07	0%	8.03E-08	3.52E-07	
191242	Benzo(g,h,i)perylene	PAH, HAP	2.26E-06	lb/1000 gal	1.23E-07	5.37E-07	0%	1.23E-07	5.37E-07	
218019	Chrysene	PAH, HAP	2.38E-06	lb/1000 gal	1.29E-07	5.65E-07	0%	1.29E-07	5.65E-07	
226368	Dibenzo(a,h)anthracene	PAH, HAP	1.67E-06	lb/1000 gal	9.06E-08	3.97E-07	0%	9.06E-08	3.97E-07	AP-42, Table 1.3-9. 5/10 Edition
206440	Fluoranthene	PAH, HAP	4.84E-06	lb/1000 gal	2.62E-07	1.15E-06	0%	2.62E-07	1.15E-06	
86737	Fluorene	PAH, HAP	4.47E-06	lb/1000 gal	2.42E-07	1.06E-06	0%	2.42E-07	1.06E-06	
193395	Indeno(1,2,3,c,d)pyrene	PAH, HAP	2.14E-06	lb/1000 gal	1.16E-07	5.08E-07	0%	1.16E-07	5.08E-07	
91203	Naphthalene	PAH, HAP	1.13E-03	lb/1000 gal	6.13E-05	2.68E-04	0%	6.13E-05	2.68E-04	
85018	Phenanthrene	PAH, HAP	1.05E-05	lb/1000 gal	5.69E-07	2.49E-06	0%	5.69E-07	2.49E-06	
129000	Pyrene	PAH, HAP	4.25E-06	lb/1000 gal	2.30E-07	1.01E-06	0%	2.30E-07	1.01E-06	
POM	Polycyclic organic matter (POM)	POM, HAP	2.11E-03	lb/1000 gal	1.14E-04	5.01E-04	0%	1.14E-04	5.01E-04	AP-42, Table 1.3-8. 5/10 Edition value of 0.0033 lb/1000 gal minus PAH's listed in AP-42, Table 1.3-9
3268-87-9	OCDD	Dioxin/Furan	3.10E-09	lb/1000 gal	1.68E-10	7.36E-10	0%	1.68E-10	7.36E-10	AP-42, Table 1.3-9. 5/10 Edition

NOTE:
Control efficiency of 99% is applied to account for the use of baghouse.
Control efficiency of 70% is applied to account for the use of SNCR.
Control efficiency of 75% is applied to account for the use of limestone injection

TABLE 17. POTENTIAL EMISSIONS CALCULATION FROM CFB BOILERS FIRED WITH SPECIFICATION USED OIL
CFB Boilers
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Annual spec used oil consumption	3,000,000	gal/yr	CSP No. 0087-02-C Attachment IIA B.5.a
Sulfur content in spec used oil	0.5	% S by wt	AES Hawaii
Lead content in spec used oil	0.0014	% Pb by wt	Spec Oil Data from supplier in 2012 to AES. Average = 8.5ppm, Max = 14ppm
Ash content in spec used oil	0.76	% Ash by wt	Spec Oil Data from supplier in 2012 to AES. Average = 0.53%, Max = 0.76%
Spec used oil hours of operation	8,760	hr/yr	24 hours per day, 365 days per year

CAS	Contaminants	Class	Emission Factor		Uncontrolled Emission		Control Efficiency	Controlled Emission		Source
			Value	Unit	lb/hr	Ton/yr		lb/hr	Ton/yr	
SOX	SO2	SOX, CAP	1475*.96	lb/1000 gal	24.16	105.84	75%	6.04	26.46	AP-42, Table 1.11-2. 10/96 Edition SOX split into SO2 and SO3 based on profile used for Fuel oil #2 of 96% as SO2 and 4% as SO3
SOX	SO3	SOX, CAP	1475*.04	lb/1000 gal	1.01	4.41	0%	1.01	4.41	
NOX	NOx	NOX, CAP	19	lb/1000 gal	6.51	28.50	70%	1.95	8.55	
630080	CO	CAP	5	lb/1000 gal	1.71	7.50	0%	1.71	7.50	
PM	PM Total	PM, CAP	64*wt% ash in oil	lb/1000 gal	16.66	72.96	99%	0.17	0.73	AP-42, Table 1.11-1. 10/96 Edition
PM	PM10 Total	PM, CAP	51*wt% ash in oil	lb/1000 gal	13.27	58.14	99%	0.13	0.58	
PM	PM2.5 Total	PM, CAP	47%	of PM Total	7.77	34.05	99%	0.08	0.34	Split into based on profile used for Fuel oil #2.
PM	PM- Filterable	PM, CAP	61%	of PM Total	10.10	44.22	99%	0.10	0.44	
PM	PM10 - Filterable	PM, CAP	30%	of PM Total	5.05	22.11	99%	0.05	0.22	
PM	PM2.5 - Filterable	PM, CAP	7%	of PM Total	1.21	5.31	99%	0.01	0.05	
PM	PM- Condensable	PM, CAP	39%	of PM Total	6.56	28.74	99%	0.07	0.29	
TOC	TOC	TOC	1	lb/1000 gal	0.34	1.50	0%	0.34	1.50	AP-42, Table 1.11-3. 10/96 Edition
VOC	VOC	VOC, CAP	0.2	lb/1000 gal	0.07	0.30	0%	0.07	0.30	AP-42, Table 1.3-3. 5/10 Edition (Fuel Oil No. 2 as Proxy)
124389	CO2	GHG	22,000	lb/1000 gal	7,534	33,000	0%	7,534	33,000	AP-42, Table 1.11-3. 10/96 Edition
74828	Methane	GHG	0.052	lb/1000 gal	1.78E-02	7.80E-02	0%	1.78E-02	7.80E-02	AP-42, Table 1.3-3. 5/10 Edition (Fuel Oil No. 2 as Proxy)
10024972	N2O	GHG	0.26	lb/1000 gal	8.90E-02	3.90E-01	0%	8.90E-02	3.90E-01	AP-42, Table 1.3-8. 5/10 Edition (Fuel Oil No. 2 as Proxy)
7647010	Hydrogen Chloride	HAP	4.30	lb/hr	4.30	18.83	0%	4.30	18.83	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10
7440382	Arsenic	Metals, HAP	1.10E-01	lb/1000 gal	3.77E-02	1.65E-01	99%	3.77E-04	1.65E-03	AP-42, Table 1.11-4. 10/96 Edition
7440439	Cadmium	Metals, HAP	9.30E-03	lb/1000 gal	3.18E-03	1.40E-02	99%	3.18E-05	1.40E-04	
7440473	Chromium	Metals, HAP	2.00E-02	lb/1000 gal	6.85E-03	3.00E-02	99%	6.85E-05	3.00E-04	
7440484	Cobalt	Metals, HAP	2.10E-04	lb/1000 gal	7.19E-05	3.15E-04	99%	7.19E-07	3.15E-06	
7439921	Lead	Metals, HAP	55*wt% lead in oil	lb/1000 gal	2.64E-02	1.16E-01	99%	2.64E-04	1.16E-03	AP-42, Table 1.11-1. 10/96 Edition
7439965	Manganese	Metals, HAP	6.80E-02	lb/1000 gal	2.33E-02	1.02E-01	99%	2.33E-04	1.02E-03	AP-42, Table 1.11-4. 10/96 Edition
7440020	Nickel	Metals, HAP	1.10E-02	lb/1000 gal	3.77E-03	1.65E-02	99%	3.77E-05	1.65E-04	AP-42, Table 1.11-4. 10/96 Edition

NOTE:
Control efficiency of 99% is applied to account for the use of baghouse.
Control efficiency of 70% is applied to account for the use of SNCR.
Control efficiency of 75% is applied to account for the use of limestone injection.

TABLE 18. POTENTIAL EMISSIONS CALCULATION FROM CFB BOILERS FIRED WITH BIOMASS
CFB Boilers
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Combined maximum feedrate Biomass, Coal, and TDF	231,000	lb/hr	CSP No. 0087-02-C Attachment IIA(C)(2)(a)
Biomass Heat Value	5500	btu/lb	Alstrom Technical Report as indicated in the 2012 permit modification application.
Maximum heat input from biomass	1,883,400	MMBtu/yr	CSP No. 0087-02-C Attachment IIA(C)(2)(c)
Maximum hourly biomass consumption	116.5	tons/hr	CSP No. 0087-02-C Attachment IIA(C)(2)(a)
Maximum annual biomass consumption	175,200	tons/yr	CSP No. 0087-02-C Attachment IIA(C)(2)(b)

CAS	Contaminants	Class	Emission Factor Value	Emission Factor Unit	Uncontrolled Emission lb/hr	Uncontrolled Emission Ton/yr	Control Efficiency	Controlled Emission lb/hr	Controlled Emission Ton/yr	Source
SOX	SO2	SOX, CAP	0.025	lb/MMBtu	32.04	23.54	75%	8.01	5.89	AP-42, Table 1.6-2. 9/03 Edition (CO for FB combustors in AP42 footnote)
NOX	NOx	NOX, CAP	0.49	lb/MMBtu	627.94	461.43	70%	188.38	138.43	
630080	CO	CAP	0.17	lb/MMBtu	217.86	160.09	0%	217.86	160.09	
PM	PM Total	PM, CAP	32.2	lb/hr	32	141		32	141	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10 (More stringent than AP-42, Table 1.6-1. 9/03 Edition)
PM	PM10 Total	PM, CAP	32.2	lb/hr	32	141		32	141	
PM	PM2.5 Total	PM, CAP	32.2	lb/hr	32	141		32	141	
PM	PM- Filterable	PM, CAP	32.2	lb/hr	32	141		32	141	
PM	PM10 - Filterable	PM, CAP	32.2	lb/hr	32	141		32	141	
PM	PM2.5 - Filterable	PM, CAP	32.2	lb/hr	32	141		32	141	
PM	PM- Condensable	PM, CAP	0.017	lb/MMBtu	22	16		22	16	AP-42, Table 1.6-1. 9/03 Edition. Factors include controls.
TOC	TOC	TOC	0.039	lb/MMBtu	50.0	36.7	0%	50.0	36.7	AP-42, Table 1.6-3. 9/03 Edition
VOC	VOC	VOC, CAP	0.017	lb/MMBtu	21.8	16.0	0%	21.8	16.0	
124389	CO2	GHG	195	lb/MMBtu	249,893	183,632	0%	249,893	183,632	AP-42, Table 1.6-3. 9/03 Edition
74828	Methane	GHG	2.10E-02	lb/MMBtu	27	20	0%	27	20	
10024972	N2O	GHG	0.013	lb/MMBtu	17	12	0%	17	12	
71556	1,1,1-Trichloroethane	HAP	3.10E-05	lb/MMBtu	3.97E-02	2.92E-02	0%	3.97E-02	2.92E-02	AP-42, Table 1.6-3. 9/03 Edition
106934	1,2-Dibromoethene	HAP	5.50E-05	lb/MMBtu	7.05E-02	5.18E-02	0%	7.05E-02	5.18E-02	
107062	1,2-Dichloroethane	HAP	2.90E-05	lb/MMBtu	3.72E-02	2.73E-02	0%	3.72E-02	2.73E-02	
78875	1,2-Dichloropropane	HAP	3.30E-05	lb/MMBtu	4.23E-02	3.11E-02	0%	4.23E-02	3.11E-02	
88062	2,4,6-Trichlorophenol	HAP	2.20E-08	lb/MMBtu	2.82E-05	2.07E-05	0%	2.82E-05	2.07E-05	
51285	2,4-Dinitrophenol	HAP	1.80E-07	lb/MMBtu	2.31E-04	1.70E-04	0%	2.31E-04	1.70E-04	
78933	2-Butanone (MEK)	HAP	5.40E-06	lb/MMBtu	6.92E-03	5.09E-03	0%	6.92E-03	5.09E-03	
100027	4-Nitrophenol	HAP	1.10E-07	lb/MMBtu	1.41E-04	1.04E-04	0%	1.41E-04	1.04E-04	
75070	Acetaldehyde	HAP	8.30E-04	lb/MMBtu	1.06E+00	7.82E-01	0%	1.06E+00	7.82E-01	
98862	Acetophenone	HAP	3.20E-09	lb/MMBtu	4.10E-06	3.01E-06	0%	4.10E-06	3.01E-06	
107028	Acrolein	HAP	4.00E-03	lb/MMBtu	5.13E+00	3.77E+00	0%	5.13E+00	3.77E+00	
71432	Benzene	HAP	4.20E-03	lb/MMBtu	5.38E+00	3.96E+00	0%	5.38E+00	3.96E+00	
117817	bis(2-Ethylhexyl)phthalate	HAP	4.70E-08	lb/MMBtu	6.02E-05	4.43E-05	0%	6.02E-05	4.43E-05	
74839	Bromomethane	HAP	1.50E-05	lb/MMBtu	1.92E-02	1.41E-02	0%	1.92E-02	1.41E-02	
56235	Carbon tetrachloride	HAP	4.50E-05	lb/MMBtu	5.77E-02	4.24E-02	0%	5.77E-02	4.24E-02	
108907	Chlorobenzene	HAP	3.30E-05	lb/MMBtu	4.23E-02	3.11E-02	0%	4.23E-02	3.11E-02	
67663	Chloroform	HAP	2.80E-05	lb/MMBtu	3.59E-02	2.64E-02	0%	3.59E-02	2.64E-02	
74873	Chloromethane	HAP	2.30E-05	lb/MMBtu	2.95E-02	2.17E-02	0%	2.95E-02	2.17E-02	
75092	Dichloromethane	HAP	2.90E-04	lb/MMBtu	3.72E-01	2.73E-01	0%	3.72E-01	2.73E-01	
100414	Ethylbenzene	HAP	3.10E-05	lb/MMBtu	3.97E-02	2.92E-02	0%	3.97E-02	2.92E-02	
50000	Formaldehyde	HAP	4.40E-03	lb/MMBtu	5.64E+00	4.14E+00	0%	5.64E+00	4.14E+00	
7647010	Hydrogen Chloride	HAP	4.30	lb/hr	4.30	18.83	0%	4.30	18.83	Limits for CFB Boilers CSP No. 0087-02-C Attachment IIA C.10 Assume all Chlorine is emitted as HCl.
95476	o-Xylene	HAP	2.50E-05	lb/MMBtu	3.20E-02	2.35E-02	0%	3.20E-02	2.35E-02	AP-42, Table 1.6-3. 9/03 Edition
87865	Pentachlorophenol	HAP	5.10E-08	lb/MMBtu	6.54E-05	4.80E-05	0%	6.54E-05	4.80E-05	
108952	Phenol	HAP	5.10E-05	lb/MMBtu	6.54E-02	4.80E-02	0%	6.54E-02	4.80E-02	
7723140	Phosphorus	HAP	2.70E-05	lb/MMBtu	3.46E-02	2.54E-02	0%	3.46E-02	2.54E-02	AP-42, Table 1.6-4. 9/03 Edition
123386	Propanal	HAP	3.20E-06	lb/MMBtu	4.10E-03	3.01E-03	0%	4.10E-03	3.01E-03	AP-42, Table 1.6-3. 9/03 Edition
123386	Propionaldehyde	HAP	6.10E-05	lb/MMBtu	7.82E-02	5.74E-02	0%	7.82E-02	5.74E-02	
100425	Styrene	HAP	1.90E-03	lb/MMBtu	2.43E+00	1.79E+00	0%	2.43E+00	1.79E+00	
127184	Tetrachloroethene	HAP	3.80E-05	lb/MMBtu	4.87E-02	3.58E-02	0%	4.87E-02	3.58E-02	
108883	Toluene	HAP	9.20E-04	lb/MMBtu	1.18E+00	8.66E-01	0%	1.18E+00	8.66E-01	
79016	Trichloroethene	HAP	3.00E-05	lb/MMBtu	3.84E-02	2.83E-02	0%	3.84E-02	2.83E-02	
75014	Vinyl Chloride	HAP	1.80E-05	lb/MMBtu	2.31E-02	1.70E-02	0%	2.31E-02	1.70E-02	
7440360	Antimony	Metals, HAP	7.90E-06	lb/MMBtu	1.01E-02	7.44E-03	99%	1.01E-04	7.44E-05	AP-42, Table 1.6-4. 9/03 Edition
7440382	Arsenic	Metals, HAP	2.20E-05	lb/MMBtu	2.82E-02	2.07E-02	99%	2.82E-04	2.07E-04	
7440417	Beryllium	Metals, HAP	1.10E-04	lb/MMBtu	1.41E-01	1.04E-01	99%	1.41E-03	1.04E-03	
7440439	Cadmium	Metals, HAP	4.10E-06	lb/MMBtu	5.25E-03	3.86E-03	99%	5.25E-05	3.86E-05	
7440473	Chromium (other than VI)	Metals, HAP (Cr)	1.75E-05	lb/MMBtu	2.24E-02	1.65E-02	99%	2.24E-04	1.65E-04	
18540299	Chromium (VI)	Metals, HAP (Cr)	3.50E-06	lb/MMBtu	4.49E-03	3.30E-03	99%	4.49E-05	3.30E-05	
7440484	Cobalt	Metals, HAP	6.50E-06	lb/MMBtu	8.33E-03	6.12E-03	99%	8.33E-05	6.12E-05	
7439921	Lead	Metals, HAP	4.80E-05	lb/MMBtu	6.15E-02	4.52E-02	99%	6.15E-04	4.52E-04	
7439965	Manganese	Metals, HAP	1.60E-03	lb/MMBtu	2.05E+00	1.51E+00	99%	2.05E-02	1.51E-02	
7439976	Mercury	Metals, HAP	3.50E-06	lb/MMBtu	4.49E-03	3.30E-03	99%	4.49E-05	3.30E-05	
7440020	Nickel	Metals, HAP	3.30E-05	lb/MMBtu	4.23E-02	3.11E-02	99%	4.23E-04	3.11E-04	
7782492	Selenium	Metals, HAP	2.80E-06	lb/MMBtu	3.59E-03	2.64E-03	99%	3.59E-05	2.64E-05	
83329	Acenaphthene	PAH, HAP	9.10E-07	lb/MMBtu	1.17E-03	8.57E-04	0%	1.17E-03	8.57E-04	

TABLE 18. POTENTIAL EMISSIONS CALCULATION FROM CFB BOILERS FIRED WITH BIOMASS
CFB Boilers
AES Hawaii, Inc.
CSP No. 0087-02-C

Parameters	Value	Unit	Source
Combined maximum feedrate Biomass, Coal, and TDF	233,000	lb/hr	CSP No. 0087-02-C Attachment BA(C)(2)(a)
Biomass Heat Value	5500	btu/lb	Alstrom Technical Report as indicated in the 2012 permit modification application.
Maximum heat input from biomass	1,883,400	MMBtu/yr	CSP No. 0087-02-C Attachment BA(C)(2)(c)
Maximum hourly biomass consumption	116.5	tons/hr	CSP No. 0087-02-C Attachment BA(C)(2)(a)
Maximum annual biomass consumption	175,200	tons/yr	CSP No. 0087-02-C Attachment BA(C)(2)(b)

CAS	Contaminants	Class	Emission Factor		Uncontrolled Emission		Control Efficiency	Controlled Emission		Source
			Value	Unit	lb/hr	Ton/yr		lb/hr	Ton/yr	
208968	Acenaphthylene	PAH, HAP	5.00E-06	lb/MMBtu	6.41E-03	4.71E-03	0%	6.41E-03	4.71E-03	AP-42, Table 1.6-3. 9/03 Edition
120127	Anthracene	PAH, HAP	3.00E-06	lb/MMBtu	3.84E-03	2.83E-03	0%	3.84E-03	2.83E-03	
56553	Benzo(a)anthracene	PAH, HAP	6.50E-08	lb/MMBtu	8.33E-05	6.12E-05	0%	8.33E-05	6.12E-05	
50328	Benzo(a)pyrene	PAH, HAP	2.60E-06	lb/MMBtu	3.33E-03	2.45E-03	0%	3.33E-03	2.45E-03	
205992	Benzo(b)fluoranthene	PAH, HAP	1.00E-07	lb/MMBtu	1.28E-04	9.42E-05	0%	1.28E-04	9.42E-05	
191242	Benzo(g,h,i)perylene	PAH, HAP	9.30E-08	lb/MMBtu	1.19E-04	8.76E-05	0%	1.19E-04	8.76E-05	
205823; 207089	Benzo(j,k)fluoranthene	PAH, HAP	1.60E-07	lb/MMBtu	2.05E-04	1.51E-04	0%	2.05E-04	1.51E-04	
207089	Benzo(k)fluoranthene	PAH, HAP	3.60E-08	lb/MMBtu	4.61E-05	3.39E-05	0%	4.61E-05	3.39E-05	
218019	Chrysene	PAH, HAP	3.80E-08	lb/MMBtu	4.87E-05	3.58E-05	0%	4.87E-05	3.58E-05	
226368	Dibenzo(a,h)anthracene	PAH, HAP	9.10E-09	lb/MMBtu	1.17E-05	8.57E-06	0%	1.17E-05	8.57E-06	
206440	Fluoranthene	PAH, HAP	1.60E-06	lb/MMBtu	2.05E-03	1.51E-03	0%	2.05E-03	1.51E-03	
86737	Fluorene	PAH, HAP	3.40E-06	lb/MMBtu	4.36E-03	3.20E-03	0%	4.36E-03	3.20E-03	
193395	Indeno(1,2,3,c,d)pyrene	PAH, HAP	8.70E-08	lb/MMBtu	1.11E-04	8.19E-05	0%	1.11E-04	8.19E-05	
91203	Naphthalene	PAH, HAP	9.70E-05	lb/MMBtu	1.24E-01	9.13E-02	0%	1.24E-01	9.13E-02	
85018	Phenanthrene	PAH, HAP	7.00E-06	lb/MMBtu	8.97E-03	6.59E-03	0%	8.97E-03	6.59E-03	
129000	Pyrene	PAH, HAP	3.70E-06	lb/MMBtu	4.74E-03	3.48E-03	0%	4.74E-03	3.48E-03	
2051243	Decachlorobiphenyl	PCB, HAP	2.70E-10	lb/MMBtu	3.46E-07	2.54E-07	0%	3.46E-07	2.54E-07	AP-42, Table 1.6-3. 9/03 Edition
2051243	Dichlorobiphenyl	PCB, HAP	7.40E-10	lb/MMBtu	9.48E-07	6.97E-07	0%	9.48E-07	6.97E-07	
68194161	Heptachlorobiphenyl	PCB, HAP	6.60E-11	lb/MMBtu	8.46E-08	6.22E-08	0%	8.46E-08	6.22E-08	
8020835	Hexachlorobiphenyl	PCB, HAP	5.50E-10	lb/MMBtu	7.05E-07	5.18E-07	0%	7.05E-07	5.18E-07	
27323188	Monochlorobiphenyl	PCB, HAP	2.20E-10	lb/MMBtu	2.82E-07	2.07E-07	0%	2.82E-07	2.07E-07	
31508006	Pentachlorobiphenyl	PCB, HAP	1.20E-09	lb/MMBtu	1.54E-06	1.13E-06	0%	1.54E-06	1.13E-06	
PCB	Tetrachlorobiphenyl	PCB, HAP	2.50E-09	lb/MMBtu	3.20E-06	2.35E-06	0%	3.20E-06	2.35E-06	
PCB	Trichlorobiphenyl	PCB, HAP	2.60E-09	lb/MMBtu	3.33E-06	2.45E-06	0%	3.33E-06	2.45E-06	
1746-01-6	2,3,7,8-TCDD	Dioxin/Furan, HAP	6.8E-14	lb/lb biomass	1.58E-08	1.19E-08	0%	1.58E-08	1.19E-08	USEPA, "An Inventory of Sources and Environmental Releases of Dioxin-Like Compounds in the United Stated for the Years 1987, 1995, and 2000", Table 4-14, November 2006. Maximum of CARB or NCASI Sampling, with nondetect set to ½ detection limit.
35822-46-9	1,2,3,4,6,7,8 HpCDD	Dioxin/Furan	9.05E-13	lb/lb biomass	2.11E-07	1.59E-07	0%	2.11E-07	1.59E-07	
67562-39-4	1,2,3,4,6,7,8 HpCDF	Dioxin/Furan	2.749E-12	lb/lb biomass	6.41E-07	4.82E-07	0%	6.41E-07	4.82E-07	
55673-89-7	1,2,3,4,7,8,9-HpCDF	Dioxin/Furan	3.44E-13	lb/lb biomass	8.02E-08	6.03E-08	0%	8.02E-08	6.03E-08	
39227-28-6	1,2,3,4,7,8-HxCDD	Dioxin/Furan	1.83E-13	lb/lb biomass	4.26E-08	3.21E-08	0%	4.26E-08	3.21E-08	
70648-26-9	1,2,3,4,7,8-HxCDF	Dioxin/Furan	7.68E-13	lb/lb biomass	1.79E-07	1.35E-07	0%	1.79E-07	1.35E-07	
57653-85-7	1,2,3,6,7,8-HxCDD	Dioxin/Furan	1.93E-13	lb/lb biomass	4.50E-08	3.38E-08	0%	4.50E-08	3.38E-08	
57117-44-9	1,2,3,6,7,8-HxCDF	Dioxin/Furan	9.41E-13	lb/lb biomass	2.19E-07	1.65E-07	0%	2.19E-07	1.65E-07	
19408-74-3	1,2,3,7,8,9-HxCDD	Dioxin/Furan	5.24E-13	lb/lb biomass	1.22E-07	9.18E-08	0%	1.22E-07	9.18E-08	
72918-21-9	1,2,3,7,8,9-HxCDF	Dioxin/Furan	3.5E-13	lb/lb biomass	8.16E-08	6.13E-08	0%	8.16E-08	6.13E-08	
40321-76-4	1,2,3,7,8-PeCDD	Dioxin/Furan	1.12E-13	lb/lb biomass	2.61E-08	1.96E-08	0%	2.61E-08	1.96E-08	
57117-41-6	1,2,3,7,8-PeCDF	Dioxin/Furan	7.9E-13	lb/lb biomass	1.84E-07	1.38E-07	0%	1.84E-07	1.38E-07	
60851-34-5	2,3,4,6,7,8-HxCDF	Dioxin/Furan	4.91E-13	lb/lb biomass	1.14E-07	8.60E-08	0%	1.14E-07	8.60E-08	
57117-31-4	2,3,4,7,8-PeCDF	Dioxin/Furan	7.41E-13	lb/lb biomass	1.73E-07	1.30E-07	0%	1.73E-07	1.30E-07	
51207-31-9	2,3,7,8-TCDF	Dioxin/Furan	7.19E-13	lb/lb biomass	1.68E-07	1.26E-07	0%	1.68E-07	1.26E-07	
3268-87-9	OCDD	Dioxin/Furan	6.026E-12	lb/lb biomass	1.40E-06	1.06E-06	0%	1.40E-06	1.06E-06	
39001-02-0	OCDF	Dioxin/Furan	1.59E-12	lb/lb biomass	3.70E-07	2.79E-07	0%	3.70E-07	2.79E-07	

NOTE:
Control efficiency of 99% is applied to account for the use of baghouse.
Control efficiency of 70% is applied to account for the use of SNCR.
Control efficiency of 75% is applied to account for the use of limestone injection.

TABLE 19: POTENTIAL EMISSIONS CALCULATION FROM COOLING TOWER
Cooling Tower
AES Hawaii, Inc.
CSP No. 0087-02-C

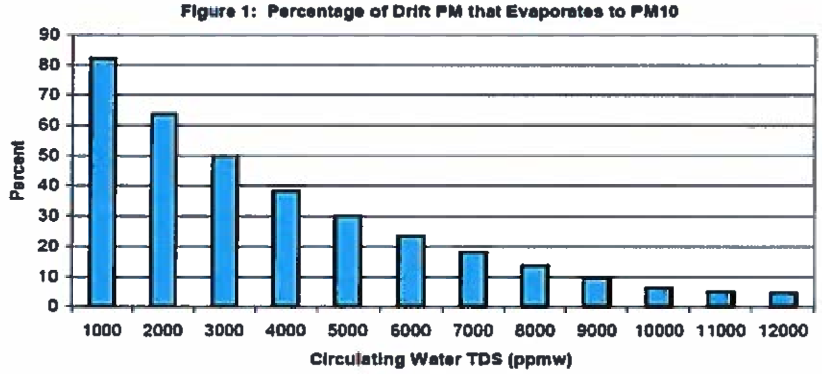
INPUT	Value	Unit	Source
Circulating rate	104,000	gal/min	CSP No. 0087-02-C Attachment IID, Section B.2
Drift loss	0.002	%	CSP No. 0087-02-C Attachment IID, Section B.3
Total dissolved solids concentration	52,000	mg/L	Proposed change to CSP No. 0087-02-C Attachment IID, Section B.4.a
Chlorine concentration	1	mg/L	CSP No. 0087-02-C Attachment IID, Section B.4.b

PM = Water Circulation Rate x Drift Rate x TDS
Method from AP-42 Fifth edition, Volume I Chapter 13.4 Wet Cooling Towers

Contaminants	Uncontrolled Emission		Control	Controlled Emission	
	lb/hr	ton/year	Efficiency	lb/hr	ton/year
Chlorine	1.04E-03	4.56E-03	0%	1.04E-03	4.56E-03
TSP	54.2	237.2	0%	54.2	237.2
PM-10	2.7	11.9	0%	2.7	11.9
PM-2.5	2.7	11.9	0%	2.7	11.9

See Appendix F - Calculating Realistic PM10 Emissions from Cooling Towers, Greystone Environmental Consultants
PM10 = <5% of Drift PM if TDS >11,000ppm.

Figure 1: Percentage of Drift PM that Evaporates to PM10



NOTE:
Conservatively assumed PM2.5 = PM10

TABLE 20: POTENTIAL EMISSIONS CALCULATION FROM ASH LOADING
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

Bed Ash Input	Value	Unit	Source
Bad Ash Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum Bed Ash Capacity	5.33	tons/hour	Production/Operating hours
Max. Bed Ash Production	46,700	tons/year	AES Hawaii, Inc.

Fly Ash Input	Value	Unit	Source
Fly Ash Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum Fly Ash Capacity	15.99	tons/hour	Production/Operating hours
Max. Fly Ash Production	140,100	tons/year	AES Hawaii, Inc.

Conditioned Ash Input	Value	Unit	Source
Conditioned Ash Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum Conditioned Ash Capacity	21.32	tons/hour	Production/Operating hours
Max. Conditioned Ash Production	186,800	tons/year	AES Hawaii, Inc.

Activity	Emission Factor			Source
	TSP	PM-10	PM-2.5	
	lb/ton	lb/ton	lb/ton	
Material Loading				
Bed Ash Storage Hopper Loading	0.0048	0.0028	0.0028	EPA AP-42, Table 11.12-2 06/06 Edition - Revised January 2012
Fly Ash Reinjection Surge Hopper Loading	0.0048	0.0028	0.0028	
Bed Ash Silo Loading	0.0048	0.0028	0.0028	
Fly Ash Silo Loading	0.0048	0.0028	0.0028	
Conditioned Ash Mixer Loading	0.572	0.156	0.156	

Activity	Uncontrolled Emissions						Control Efficiency	Controlled Emissions					
	TSP		PM-10		PM-2.5			TSP		PM-10		PM-2.5	
	lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year		lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year
Material Loading													
Bed Ash Storage Hopper Loading	0.0256	0.1121	0.0149	0.0654	0.0149	0.0654	99%	0.00026	0.00112	0.00015	0.00065	0.00015	0.00065
Fly Ash Reinjection Surge Hopper Loading	0.0768	0.3362	0.0448	0.1961	0.0448	0.1961	99%	0.00077	0.00336	0.00045	0.00196	0.00045	0.00196
Bed Ash Silo Loading	0.0256	0.1121	0.0149	0.0654	0.0149	0.0654	99%	0.00026	0.00112	0.00015	0.00065	0.00015	0.00065
Fly Ash Silo Loading	0.0768	0.3362	0.0448	0.1961	0.0448	0.1961	99%	0.00077	0.00336	0.00045	0.00196	0.00045	0.00196
Conditioned Ash Mixer Loading	12.20	53.42	3.33	14.57	3.3266	14.5704	99%	0.12197	0.53425	0.03327	0.14570	0.03327	0.14570
Total	12.40	54.32	3.45	15.09	3.44599087	15.09344	-	0.1240	0.5432	0.0345	0.1509	0.03446	0.150934

NOTE:
Conservatively assumed PM2.5 = PM10

TABLE 21: POTENTIAL EMISSIONS CALCULATION FROM ASH SEPARATORS
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

Bed Ash Input	Value	Unit	Source
Bed Ash Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum Bed Ash Capacity	5.33	tons/hour	Production/Operating hours
Bed Ash Production	46,700	tons/year	AES Hawaii, Inc.

Fly Ash Input	Value	Unit	Source
Fly Ash Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Maximum Fly Ash Capacity	15.99	tons/hour	Production/Operating hours
Fly Ash Production	140,100	tons/year	AES Hawaii, Inc.

Activity	Emission Factor			Source
	TSP	PM-10	PM-2.5	
	lb/ton	lb/ton	lb/ton	
Bed Ash Mechanical Separator with Fabric Filter	0.0225	0.0104	0.0041	EPA AP-42, Table 11.19.2-4 08/04 Edition
Fly Ash Mechanical Separator with Fabric Filter	0.0225	0.0104	0.0041	EPA AP-42, Table 11.19.2-4 08/04 Edition

Activity	Uncontrolled Emissions						Controlled Emissions						
	TSP		PM-10		PM-2.5		Control Efficiency	TSP		PM-10		PM-2.5	
	lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year		lb/hour	ton/year	lb/hour	ton/year	lb/hour	ton/year
Bed Ash Mechanical Separator with Fabric Filter	-	-	-	-	-	-	-	0.120	0.525	0.055	0.243	0.022	0.096
Fly Ash Mechanical Separator with Fabric Filter	-	-	-	-	-	-	-	0.360	1.576	0.166	0.729	0.066	0.287
Total								0.480	2.102	0.222	0.971	0.087	0.383

TABLE 22: POTENTIAL EMISSIONS CALCULATION FROM ASH DROPS TO TRUCKS FROM CONDITIONED ASH MIXER
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Average Hourly Conditioned Ash Production	21.32	tons/hour	Max. annual capacity / operating hours per year
Maximum Annual Conditioned Ash Production	186,800	tons/year	AES Hawaii
Operating Hours	8,760	hours/year	24 hours per day, 365 days per year
Number of Uncontrolled Drops	1	n/a	Drops to trucks from conditioned ash mixer

E =k*0.0032*(((U/5)^1.3)/(M/2)^1.4)

where E = Emission factor (lb/ton)
k = particle size multiplier

M = moisture content (%)
U = mean wind speed (mph)

	Value	Source
k (TSP)	0.74	AP42,13.2.4 (11/06)
k (PM-10)	0.35	AP42,13.2.4 (11/06)
k (PM-2.5)	0.2	AP42, 13.2.4, (11/06)
U	8.1	WRCC, see Appendix C
M	27	AES Hawaii, Inc.

Contaminant	Emission Factor	Uncontrolled Emission		Control	Controlled Emission	
	lb/ton	lb/hr	ton/year	Efficiency	lb/hr	ton/year
Conditioned Ash Drop						
TSP	1.16E-04	2.47E-03	1.08E-02	50%	1.24E-03	5.42E-03
PM-10	5.48E-05	1.17E-03	5.12E-03	50%	5.85E-04	2.56E-03
PM-2.5	3.13E-05	6.68E-04	3.34E-07	50%	3.34E-04	1.67E-07

Note:
(1) As a worst case scenario, all of the bed ash and fly ash is assumed to go to the conditioned ash mixer.

TABLE 23: POTENTIAL EMISSIONS CALCULATION FROM CONDITIONED ASH TRUCKS TRAVELING ON PAVED ROADS
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

$E_{ext} = [k*(sL)^{0.91}*(W)^{1.02}]*[1-P/(4N)]$ AP42,13.2.1 Equation (2) January 2011 edition

Eext = annual average emission factor in the same units as k
k = particle size multiplier for particle size of interest (lb/VMT)
sL = road surface silt loading (g/m2)
W = average weight of vehicles traveling the road (tons)
P = number of days with at least 0.01 inches of precipitation per year
N = number of days in the averaging period (356 days for annual)

Parameter	Value			Units	Source
	PM-2.5	PM-10	PM-30		
k	0.00054	0.0022	0.011	lb/VMT	AP42, Table 13.2.1-1 (1/11)
sL	0.037	0.037	0.037	g/m2	CARB methodology 7.9 for paved road
W	20	20	20	tons	AES Hawaii, Inc.
P	95	95	95	days	WRCC data (see Appendix C)
N	365	365	365	days	Annual averaging period
E_{ext}	0.0005	0.0022	0.0109	lb/VMT	AP42, Table 13.2.1 Equation (2) (1/11)

	Value	Unit
Truck Load	10	ton/trip
Distance Traveled by truck	0.25	miles/trip
Facility run-time	8,760	hours/yr
Annual Production	186,800	ton/year
# of trip per year	18,680	trip/year
Total Distance VMT	4,670	miles/year

Emission	PM-2.5		PM-10		PM-30	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Uncontrolled	0.0003	0.0012	0.0012	0.0051	0.0058	0.0254
Controlled(1)	0.0001	0.0006	0.0006	0.0025	0.0029	0.0127

Note:
(1) 50% control factor is applied to account for water spray
(2) The emissions from conditioned ash trucks traveling on paved roads covers the emissions from the bed ash and fly ash trucks traveling on paved roads.

TABLE 24: ANALYTICAL RESULTS FOR METAL CONCENTRATIONS IN BED ASH
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

Metals	Lab Analytical Results [1]		Average[2]	HAP?
	5/1/2004	11/14/2005		
	mg/kg	mg/kg	mg/kg	
Antimony	0.653	0.4	0.5265	Yes
Arsenic	27.4	25.9	26.65	Yes
Barium	381	314	347.5	No
Beryllium	1.45	1.5	1.475	Yes
Cadmium	0.218		0.218	Yes
Chromium	82.5	48.3	65.4	Yes
Copper	29.3		29.3	No
Lead	2.37	4.04	3.205	Yes
Mercury	0.049	0.02	0.0345	Yes
Molybdenum	3.18		3.18	No
Nickel	262		262	Yes
Selenium	0.392		0.392	Yes
Silver	0.435	0.2	0.3175	No
Thallium	0.435	0.5	0.4675	No
Zinc	2530	788	1659	No

Note:
(1) Analytical results obtained from AES Hawaii, Inc.
(2) Due to limited available data, the average concentrations are used to estimate metals emissions.

TABLE 25: ANALYTICAL RESULTS FOR METAL CONCENTRATIONS IN FLY ASH
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

Test Number	Analytical Results[1]														
	Antimony	Arsenic	Barium	Beryllium	Cadmium	Chromium	Copper	Lead	Mercury	Molybdenum	Nickel	Selenium	Silver	Thallium	Zinc
	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
18-3-1-1	0.189	8.4	361	0.44	0.309	35.2	26.6	18.5	0.327	1.59	40	0.36	0.125	0.576	103
18-3-1-2	1.2	29.2	735	2.94	1.05	56	39.8	36.2	1.05	4.82	63.9	1.61	3.86	1.19	465
18-3-2-1	0.947	17.6	416	1.52	0.947	36.8	23.6	18.8	0.947	2.77	38.4	1.21	[illegible]	0.947	284
18-3-2-2	1.12	17.3	534	4.02	1.12	48.6	32.3	15.1	1.12	4.88	144	1.12	1.12	1.12	419
18-3-3-1	1.08	8.7	333	2.38	1.08	92.4	23.8	12.9	1.08	3.65	181	1.08	1.08	1.08	592
18-3-3-2	0.909	17.3	794	3.62	0.909	46.1	35.6	24.9	0.909	4.44	108	0.91	0.909	0.909	584
18-4-4-1	0.389	13.1	755	1.32	0.197	40.2	31.3	21	0.503	3.99	124	1.31	0.88	0.847	378
18-4-4-2	0.81	15	895	3.94	0.229	42.2	41	25.8	0.653	2.29	76.5	1.86	0.266	0.912	226
18-4-5-1	0.132	2.2	315	3.49	0.216	22	38.5	21.5	1.04	2.48	60.9	0.5	0.524	0.608	1100
18-4-5-2	0.214	2.7	467	1.35	0.214	23.9	56.2	27.4	0.624	2.82	56.7	0.62	0.355	0.714	997
18-4-6-1	0.301	8.2	538	3.67	0.258	34.3	44.3	26	0.586	3.1	43.5	1.34	0.331	0.657	1160
18-4-6-2	0.286	8	552	3.65	0.23	33.5	40.1	22	0.544	3.52	50.4	1.39	0.647	0.631	611
19-1-7-1	0.234	11.5	510	1.98	0.234	50.4	31.3	23.5	0.568	3.73	110	0.77	0.234	0.754	871
19-1-7-2	0.29	16.3	681	2.89	0.258	61.8	38.8	32	0.846	5.68	179	0.26	0.491	0.956	1030
19-1-8-1	0.253	13.9	507	2.58	0.253	52.8	34.9	24	0.584	5.28	250	0.26	0.524	0.608	1100
19-1-8-2	0.259	13.2	468	2.9	0.259	61.7	40	20.3	0.517	6.25	282	2.15	0.371	0.837	107
19-1-9-1	0.253	10	506	1.84	0.253	25.1	36.9	20.1	0.343	6.26	67.4	0.99	0.253	0.541	1330
19-1-9-2	0.214	11.6	386	1.11	0.214	13.9	33.4	19.9	0.494	4	35.6	1.26	0.214	0.709	807
19-2-10-1	0.255	9.2	323	2.09	0.255	21	27.2	17.5	0.508	2.78	30.7	0.82	0.255	0.658	799
19-2-10-2	0.25	21.8	466	2.57	0.253	45.4	28.2	11	0.395	2.41	49.6	0.5	0.253	0.273	111
19-2-11-1	0.253	10.8	520	1.6	0.253	30.7	24.1	10.2	0.359	2.95	42.1	0.63	0.253	0.376	65.2
19-2-11-2	0.255	20.1	676	2.09	0.255	38.9	33.5	0.7	4.89	49.5	0.346	0.26	0.255	0.841	496
19-2-12-1	0.278	12.3	573	2.86	0.278	56.2	30.9	17.8	0.441	4.65	231	0.82	0.293	0.733	86.5
19-2-12-2	1.15	8.4	412	1.94	1.15	22.5	35.2	18.4	1.15	3.84	40.2	1.44	1.15	1.15	57.8
19-3-1-1	0.255	6.8	513	6.34	6.34	42.8	79.7	22.9	6.34	6.34	54.9	6.34	6.34	3.17	117
19-3-1-2	6.34	4.8	346	6.34	6.34	41.9	74.9	20.3	6.34	6.46	36.5	6.34	6.34	3.17	50.8
19-3-2-1	0.254	2.5	237	2.54	0.254	24.4	36.4	15.4	2.54	2.65	24.7	2.54	2.54	2.54	44.4
19-3-2-2	3.18	4.7	462	3.18	3.18	50	95.7	29.5	3.18	5.42	43.4	3.18	3.18	3.18	87.8
19-3-3-1	3.17	7.5	372	3.17	3.17	16.6	22.2	14.9	3.17	3.82	44.5	3.17	3.17	3.17	253.7
19-3-3-2	3.1	4.9	264	3.1	3.1	10.3	31.8	10.8	3.1	4.51	28.3	3.1	3.1	3.1	41.2
19-4-4-1	3.15	3.5	189	3.15	3.15	8.7	29.9	12.5	3.15	3.39	25	3.15	3.15	3.15	46.1
19-4-4-2	3.11	9.3	306	3.46	3.11	23	42	14.8	3.11	3.11	45.6	3.11	3.11	3.11	67.3
19-4-5-1	3.12	12.8	457	4.01	3.12	33.5	48.2	23.4	3.12	7.08	50.7	3.12	2.54	3.12	65.6
19-4-5-2	3.06	13.8	471	3.06	3.06	29	36.9	23.9	3.06	3.86	42.4	3.06	3.06	3.06	42.3
19-4-6-1	3.18	5	396	3.18	3.18	15.3	23.3	11.1	3.18	3.18	30.6	3.23	3.18	3.18	92.9
19-4-6-2	3	13	624	3	3	21.4	22.5	15.6	3	6.18	47.5	3	3	3	62.4
20-1-7-1	2.56	22.4	427	3.55	2.56	19.2	38.1	20.6	2.56	5.26	62.8	2.56	2.56	2.56	120
20-1-7-2	2.58	18.9	381	2.69	2.58	20.8	21.6	13.4	2.58	3.85	44.1	2.58	2.58	2.58	64.4
20-1-8-1	3.03	22.7	481	3.03	3.03	21.5	24.5	13.2	3.08	6.22	49.4	3.08	3.03	3.03	79.2
20-1-8-2	2.81	18.9	488	3.78	2.81	38	54.8	13.5	2.81	8.54	62.5	3.02	2.81	2.81	73.6
20-1-9-1	2.96	12.8	419	2.96	2.96	19	28.9	15	2.96	5.37	36.5	2.96	2.96	2.96	44.4
20-1-9-2	2.61	9	396	2.71	2.61	19.4	32	14.6	2.61	5.13	40.4	2.61	2.61	2.61	47.9
20-2-10-1	2.55	20.5	815	3.66	2.55	22	30	15	2.55	15.1	41.8	45.1	2.55	2.55	81.8
20-2-10-2	2.9	19.4	851	2.9	2.9	32.9	28.5	13.4	2.9	14.9	43.1	41.4	2.9	2.9	83.6
20-2-11-1	3.05	16.8	976	3.05	3.05	15.4	28.2	14.7	3.05	9.49	43.6	15.3	3.05	3.05	233
20-2-11-2	2.85	17.6	700	3	2.85	45.3	40.1	18.1	2.85	6.01	146	3.46	2.85	2.85	273
20-2-12-1	2.74	15.4	705	3.62	2.74	53.5	39.8	17.5	2.74	8.46	132	2.74	2.74	2.74	242
20-2-12-2	5.36	24.1	1739	5.64	5.36	64.5	78.8	36.1	5.36	10.8	178	5.5	5.36	5.2	527
20-3-1-1	2.95	11.8	425	4.95	2.95	47.8	41.7	16.7	2.95	7.88	119	5.01	2.95	2.95	165
20-3-1-2	2.6	11.5	411	6.4	2.6	43	36.1	16.5	2.6	7.16	95.5	4.67	2.6	2.6	145
20-3-2-1	0.408	10.4	302	7.46	0.013	24.9	38.1	18.8	2.48	8.33	69	3.13	0.263	0.961	92.8
20-3-2-2	2.9	18.2	798	7.49	2.9	39.5	60.6	40.4	2.9	13.5	148	2.9	2.9	2.9	201
20-3-3-1	2.96	10.7	526	4.82	2.96	26.4	47.3	18.8	2.96	7.27	105	2.96	2.96	2.96	149
20-3-3-2	0.002	13.2	434	9.91	0.002	33.3	48.1	18.4	0	8.93	73.2	0	0.002	0.002	150
20-4-4-1	3.15	14.8	886	7.4	3.15	31.3	34.5	22.6	3.15	10.3	80.4	10.2	3.15	3.15	191
20-4-4-2	2.9	16.5	1150	7.02	2.9	29.1	36.8	27.8	6.01	14.1	85.8	9.8	2.9	2.9	390
20-4-5-1	3.02	11.6	855	7.79	3.02	30.2	45.8	18.7	3.02	10.5	108	3.02	3.02	3.02	143
20-4-5-2	3.3	13.4	508	5.3	3.3	32.7	42.1	17.9	3.3	7.9	92.8	3.3	3.3	3.3	164
20-4-6-1	0.4	7.4	420	6	0.4	25	42.7	16.3	0.4	7.5	83.3	0.84	1.2	0.72	136
20-4-6-2	0.4	9.8	587	4.8	0.4	15.7	28.6	15.5	0.154	8	70.8	0.53	0.901	0.74	120
21-1-7-1	0.402	10.6	405	2.6	0.402	16.6	21.6	15	0.221	16.2	36.4	8.53	0.53	0.7	80.7
21-1-7-2	0.39	7.1	457	2.6	0.39	22.6	25.7	13.3	0.39	15.4	47	9.97	0.39	0.602	88.8
21-1-8-1	0.396	11.7	444	3.01	0.39	19.1	26.2	15.1	0.39	16.7	46.9	11.9	0.388	0.75	105
21-1-8-2	0.396	8	492	3.49	0.396	19.8	10.5	13.8	0.42	19.7	21.1	5.84	0.398	0.73	82.5
21-1-9-1	0.41	19.1	850	3.99	0.52	27.9	39.7	19.2	0.49	16	46.6	21.8	0.41	1.2	85.4
21-1-9-2	0.38	14.2	1030	3	0.67	39.2	43.6	22.7	0.57	19.9	53	23.8	0.38	1.5	93.9
21-2-10-1	0.402	31.7	1260	2.8	0.45	46.5	67.3	19	0.45	15.3	64.5	36.2	0.4	1.3	94.9
21-2-10-2	0.78	29.9	1120	2.6	0.41	33.5	52.2	16.5	0.42	15.6	49.2	30.8	0.41	1.2	41.1
21-2-11-1	0.57	19.4	1130	3.2	0.43	37.9	42	17.6	0.43	14.9	48.5	34.6	0.38	1.3	68.1
21-2-11-2	0.4	18.2	951	2.7	0.53	24.3	34.7	13.7	0.42	12.5	34.9	25.9	0.4	1.1	53.5
21-2-12-1	0.4	14.5	1250	2.7	0.87	37.5	48.1	21.3	0.59	19.7	58.7	41.2	0.4	1.4	101
21-2-12-2	0.4	11.9	1280	1.2	0.4	57.8	36.7	15.1	0.4	9.8	77.8	3.7	0.4	0.49	100
21-3-1-1	0.4	13.5	1060	1.2	0.4	44.4	30.4	11.2	0.4	7.9	53.3	3.1	0.4	0.4	78.9
21-3-1-2	0.4	12.8	1153	2.1	0.4	53.1	33.7	13	0.4	6.3	70.3	4.3	0.4	0.59	104
21-3-2-1	0.41	12.1	1000	1.8	0.39	42.1	28.9	12.3	0.41	5.4	53.7	4.4	0.41	0.62	82.1
21-3-2-2	0.39	12.5	856	1.8	0.39	38	25.3	11.8	0.39	5.7	50.9	3.7	0.39	0.52	101
21-3-3-1	0.4	17.5	743	2	0.63	26.1	30.8	12.8	0.4	10	34.5	19.8	0.4	0.96	60.6
21-3-3-2	0.41	13	633	1.6	0.53	19.8	26.2	10.9	0.41	7.5	30.8	17.4	0.41	0.83	52.8
21-4-4-1	0.4	14.6	843	2	0.48	28.4	34	13.8	0.4	9.9	40.6	22	0.4	1.06	74.8
21-4-4-2	0.4	16	1042	2.3	0.4	38.6	42.1	15.5	0.4	11.7	55.3	21.4	0.4	1.02	103.6
21-4-5-1	0.72	39.2	813	2.8	0.84	25	44.1	13.4	0.41	17.4	50.3	21.8	0.4	1.2	70.9
21-4-5-2	0.36	12.1	713	2.7	1.03	28.1	33.4	13.1	0.46	14.1	42.2	24.9	0.36	1.3	62.7
21-4-6-1	0.39	32.8	703	2.6	0.92	26.6	28.8	13	0.48	15.7	45	28.5	0.35	1.3	55.9
21-4-6-2	0.34	14.8	817	3.6	1.2	32	39.6	18	0.58	13.3	49.8	23.4	0.34	1.2	102
22-1-7-1	0.61	14.5	667	3.4	1.04	25.8	36.8	14.3	0.47	13.6	34.9	22.7	0.35	1.01	53
22-1-7-2	0.34	13.4	803	3.3	1	33	38.5	15.8	0.55	12.9	40.6	28.1	0.34	1.2	73
22-1-8-1	0.35	29.1	722	3.1	0.97	33.5	34.9	15.1	0.51	14.4	52.7	30.5	0.35	1.05	86
22-1-8-2	0.69	20.2	792	2.5	0.94	24.7	39.4	11.7	0.63	15.6	39.1	31.9	0.37	1.1	53.6
22-1-9-1	0.44	30.7	793	2.77	0.93	27.4	40.1	13.2	0.59	13.4	46.5	28.7	0.34	1.08	49.9
22-1-9-2	0.35	17.9	683	3.12	0.94	28.8	34.6	12.3	0.55	11.1	41.1	22.1	0.35	1.07	48.5
22-2-10-1	0.44	9.1	857	3.7	1.1	32.7	45.1	14.6	0.64	15.9	53	24.2	0.38	1.2	80.5
22-2-10-2	0.38	16.3	818	2.8	0.72	26.5	31.6	12.7	0.52	12	45	20.2	0.33	1.1	72.3
22-2-11-1	0.33	11.1	463	2.4	0.33	27.2	31.5	13.6	1.6	2.6	50.3	2.3	0.35	0.53	41
22-2-11-2	0.54	11.1	955	2.96	0.34	24.6	29.2	12.5	0.38	9.02	26.1	12.2	0.57	0.94	34
22-2-12-1	0.35	9.9	546	2.6	0.35	25.4	31.3	12.5	0.35	4.7	26.7	5.02	0.35	0.68	22.6
22-2-12-2	0.34	25.4	692	2.7	0.34	25.7	31.7	14.6	0.56	10.5	26.9	18.1	0.34	1.1	29.1
Mean	1.28	14.32	653.08	3.32	1.40	33.11	37.36	17.40	1.53	8.86	67.03	9.75	1.40	1.59	220.05
Standard Deviation	1.35	6.96	280.86	1.63	1.41	13.77	13.36	6.09	1.50	6.37	49.14	11.57	1.46	1.07	291.61
Upper 95% Confidence Level	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Upper 95% Concentration[2]	3.52	25.87	1119.60	6.04	3.75	55.98	59.55	27.51	4.03	19.35	148.65	28.97	3.82	3.38	704.43

Note:
(1) Analytical results obtained from AES Hawaii, Inc.
(2) Upper 95% Concentration = Mean + Upper 95% Confidence Level x Standard Deviation
95% confidence interval for the concentration mean is used for emission calculation as recommended by EPA.
(3) Gray areas indicate non-detect results. Assumed equal to detection limit

TABLE 26: ANALYTICAL RESULTS FOR METAL CONCENTRATIONS IN CONDITIONED ASH
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

Test Number	Analytical Results[1]														
	Antimony	Arsenic	Barium	Beryllium	Cadmium	Chromium	Copper	Lead	Mercury	Molybdenum	Nickel	Selenium	Silver	Thallium	Zinc
	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
18-3-1-1	0.99	9.2	1310	1.73	0.115	47.1	59.8	18.5	0.327	2.28	69.2	0.12	0.115	0.97	88.3
18-3-1-2	1.2	29.2	735	6.8	1.15	36.5	54.1	36.2	1.15	4.82	45.8	2.07	2.28	1.19	465
18-3-2-1	1.33	23.5	791	4.2	1.08	50.3	34	15.1	1.08	4.03	81.1	1.08	1.08	1.08	287
18-3-2-2	0.86	15	193	3.59	0.86	25.5	35.8	35.4	0.856	4.53	28.4	1.89	0.86	0.86	176
18-3-3-1	0.856	14.9	333	3.19	0.856	45.8	34.3	12.9	0.856	4.36	122	0.86	0.856	0.86	370
18-3-3-2	1.1	9.9	407	2.45	1.1	73.3	25.7	14.9	1.1	4	134	1.1	1.1	1.1	177
18-4-4-1	0.395	10.9	369	1.05	0.21	33.2	28.5	20.5	0.355	3.93	54.5	0.3	2.28	0.61	905
18-4-4-2	0.178	12	386	2.71	0.28	36	39.2	25.1	0.438	2.68	40.7	0.09	1.395	0.682	479
18-4-5-1	0.254	6.7	288	1.39	0.25	22.1	30.9	15.1	0.296	2.84	35.5	0.43	0.41	0.422	830
18-4-5-2	0.203	2.5	334	1.24	0.2	22	30	17.5	0.337	0.98	40.6	0.45	0.27	0.53	272
18-4-6-1	0.281	7.6	493	4.05	0.28	41.4	37.6	17.5	0.448	3.57	60.7	0.53	0.402	0.47	331
18-4-6-2	0.344	11.3	347	1.41	0.25	36.5	27.5	11.6	0.261	3.5	49	0.4	0.528	0.33	263
19-1-7-1	0.262	14.9	446	2.02	0.26	57.8	29.2	19	0.352	4.19	116	0.61	0.262	0.63	871
19-1-7-2	0.313	45	908	7.86	0.29	240	54.1	51.5	0.939	10.5	609	0.29	1.05	1.65	1630
19-1-8-1	0.284	12.5	280	2.37	0.29	85.2	23.3	14	0.301	4.27	236	0.29	0.41	0.524	146
19-1-8-2	0.287	22.7	484	3.55	0.29	40.4	28.1	17.1	0.287	6.87	63.3	0.88	0.29	0.47	895
19-1-9-1	0.288	13.2	470	2.72	0.29	43.1	47.3	20.1	0.307	7.5	122	0.78	0.288	0.54	1670
19-1-9-2	0.233	11.3	317	1.24	0.23	14.3	17.8	13.7	0.332	3.12	29.8	0.86	0.233	0.53	779
19-2-10-1	0.288	12.5	567	3.67	0.29	34.2	40.2	32.5	0.712	5.25	47.3	1.02	0.288	1.17	605
19-2-10-2	0.281	8.1	551	3.87	0.28	31.1	26.9	14.1	0.355	2.79	35.6	0.63	0.281	0.472	366
19-2-11-1	0.282	12	565	1.58	0.28	31.7	23.7	9.3	0.303	3.23	40.5	0.64	0.28	0.384	56.2
19-2-11-2	0.287	10.4	637	0.7	0.29	28.2	21.5	9.5	0.292	4.48	39	0.3	0.29	0.32	61.3
19-2-12-1	0.278	15.8	269	1.22	0.29	31.8	16.2	5	0.287	5.19	37.3	0.29	0.287	0.29	196
19-2-12-2	1.3	12.5	474	2.03	1.3	25.3	26.2	10.4	1.3	4.43	47.6	1.3	1.3	1.3	95.5
19-3-1-1	4.43	9.1	422	4.43	4.43	47.9	96.6	19.3	4.43	4.43	62.1	4.43	4.43	4.43	96.2
19-3-1-2	6.34	6.3	254	6.34	6.34	34	55.4	18.5	6.34	6.34	29.4	6.34	6.34	3.37	44.4
19-3-2-1	3.97	4	296	3.97	3.97	29.6	44.7	20.6	3.97	3.97	33.4	3.97	3.97	3.97	65.3
19-3-2-2	3.66	9.8	406	3.66	3.66	32.4	33.2	13.4	3.66	4.6	44	3.66	3.66	3.66	93
19-3-3-1	3.65	9.1	496	3.65	3.65	22.8	30.8	14.7	3.65	3.65	43.2	3.65	3.65	3.65	90.4
19-3-3-2	3.54	9.1	258	3.54	3.54	20.2	29.7	9.9	3.54	5.07	45.3	3.54	3.54	3.54	72.4
19-4-4-1	3.61	7.7	256	3.61	3.61	22.4	25.4	11.2	3.61	3.61	39.4	3.61	3.61	3.61	46.2
19-4-4-2	3.51	8.3	378	3.58	3.51	24.5	32.7	17.5	3.51	3.51	46.6	3.51	3.51	3.51	68.8
19-4-5-1	3.57	11.6	465	4.14	3.57	30.2	39.6	22.8	3.57	6.7	50.7	3.57	3.57	3.57	65.3
19-4-5-2	3.35	12.2	472	3.35	3.35	28.2	26.6	15.5	3.35	3.35	50.5	3.35	3.35	3.35	105
19-4-6-1	3.67	12.4	454	3.67	3.67	25.5	25.2	11.3	3.67	3.67	46.4	3.67	3.67	3.67	56.9
19-4-6-2	3.73	20.1	429	3.75	3.73	28.5	30.2	15.4	3.73	4.85	69.4	7.36	3.73	3.73	207
20-1-7-1	3.05	20.1	598	3.05	3.05	20.3	37.4	13.4	3.05	4.08	78.6	3.05	3.05	3.05	113
20-1-7-1	0.48	16.6	662	2.5	0.48	24.7	19.4	12.6	0.48	6.4	46.5	0.71	0.48	0.56	75
20-1-7-2	2.97	26.3	232	5.24	2.97	26.4	32.3	14.3	2.97	2.97	67.3	2.97	2.97	2.97	116
20-1-8-1	3.46	24.2	332	3.46	3.46	21.3	21.5	10.6	3.46	3.91	50.7	3.46	3.46	3.46	104
20-1-8-2	2.81	18.9	488	3.78	2.81	38	34.8	13.5	2.81	8.54	62.5	3.02	2.81	2.81	73.6
20-1-9-1	3.27	8.7	191	4.23	3.27	16.5	31.1	10.3	3.27	5.73	43.2	3.27	3.27	3.27	63.6
20-1-9-2	3.13	23.2	581	3.13	3.13	22.1	24.1	9.4	3.13	10.9	37.2	22.6	3.13	3.13	93.8
20-2-10-1	2.95	15.3	497	3.97	2.95	15.8	38.1	13	2.95	9.88	65.8	22	2.95	2.95	104
20-2-10-2	3.57	13.4	330	3.57	3.57	80.4	24.7	12.5	3.57	5.43	173	15.8	3.57	3.57	88.8
20-2-11-1	3.53	17.6	492	6.67	3.53	91.9	38.8	19.2	3.53	8.34	312	3.53	3.53	3.58	152
20-2-11-2	3.48	16.3	429	3.72	3.48	28.2	42.8	21.4	3.48	7.25	75.8	3.97	3.48	3.48	136
20-2-12-1	3.58	10.2	306	8.01	3.6	18.3	41.3	17.1	3.6	7.52	67.8	3.6	3.6	3.6	112
20-2-12-2	3.12	15.3	443	11.4	3.12	22.9	46.1	17.8	3.12	9.39	69.5	3.12	3.12	3.12	85.2
20-3-1-1	3.54	13.9	231	5.38	3.54	25	47.9	17.3	3.54	8.67	64.4	3.54	3.54	3.54	82.9
20-3-1-2	3.04	12	225	6.1	3.04	23.1	34.1	13.9	3.04	8.21	46.3	3.04	3.04	3.04	75.6
20-3-2-1	2.94	12.3	312	8.75	2.94	18.4	41.2	21.2	2.94	11	55.4	2.94	2.94	2.94	86.8
20-3-2-2	2.51	6.5	471	8.33	2.51	16.8	33.4	17.7	2.51	5.45	49.6	2.51	2.51	2.51	85
20-3-3-1	3.26	9.1	641	5.09	3.26	22.8	24.8	14.2	3.26	5.67	53.7	3.26	3.26	3.26	107
20-3-3-2	2.79	25.9	607	6.84	2.79	43.9	38.3	9.7	2.79	24.3	72.2	8.51	2.79	2.79	296
20-4-4-1	3.2	24.2	776	8.4	3.2	31.2	27.7	12.9	3.2	18.7	89.3	16.3	3.2	3.2	275
20-4-4-2	3	21.7	816	9.81	3	21.2	26.5	11	3	21.3	85.3	13.4	3	3	512
20-4-5-1	3.1	27.8	801	4.16	3.1	23.2	29.6	9.5	3.1	28.4	77.1	8.3	3.1	3.1	116
20-4-5-2	4.4	13.7	345	4.4	4.4	21.7	24.6	9	4.4	13.4	40.4	4.9	4.4	4.4	81.3
20-4-6-1	0.46	14.4	379	3.7	0.46	16.7	18.5	10.3	0.46	14.3	33.4	6.03	0.46	0.56	62.3
20-4-6-2	0.45	11.1	425	2.6	0.45	13.6	26.5	10.3	0.148	11.3	30.4	3.8	0.69	0.6	56.5
21-1-7-2	0.47	16.6	667	2.4	0.47	36.5	26.3	12.3	0.47	6.6	58.7	2.5	0.47	0.49	78
21-1-8-1	0.44	18.1	944	1.4	0.44	24.9	23.6	16	0.44	5.3	45.5	1.2	0.44	0.6	82.1
21-1-8-2	0.46	27.2	881	2.95	0.46	29	35.5	15.8	0.46	12.8	63.3	12.9	0.46	0.91	65.1
21-1-9-1	0.58	24.5	717	3.7	0.58	28.8	31.6	13.1	0.58	13.7	43.1	14.2	0.58	0.8	54.6
21-1-9-2	0.48	27	878	2.97	0.51	35	51.8	18.6	0.48	20.6	64.2	21.8	0.48	1.2	75.8
21-2-10-1	0.43	30.5	995	2.9	0.43	40.6	49.4	12.7	0.43	15.3	60.3	19.1	19.1	0.81	83.2
21-2-10-2	0.67	37.4	1150	3.9	0.43	45	47.8	12.9	0.41	17.7	63.5	17.1	0.43	0.84	75.4
21-2-11-1	0.72	23.4	1230	4	0.42	46.4	48.9	13.9	0.45	15.1	64.2	28.2	0.42	0.95	96.7
21-2-11-2	0.72	17.4	873	3.4	0.46	31.2	35.7	11.6	0.46	12.4	44.4	20.6	0.46	0.82	78
21-2-12-1	0.46	18.2	1100	3.2	0.46	35.1	35.5	15.1	0.46	13.9	61.9	27	0.46	0.93	45.9
21-2-12-2	0.43	18.4	1120	2.6	0.43	54.5	37.1	9.4	0.43	13.2	82	9	0.43	0.46	99.5
21-3-1-1	0.46	22.7	1110	1.4	0.46	39.4	38.8	10.7	0.46	15.2	36.4	8.1	0.46	0.53	103
21-3-1-2	0.47	18.7	1014	1.7	0.47	31.8	34.9	12.7	0.47	7	52.2	6	0.47	0.84	71.4
21-3-2-1	0.47	19.6	862	2	0.47	29.1	30.1	10.6	0.47	7.9	38.1	9.5	0.47	0.74	59.8
21-3-2-2	0.46	16.7	474	1.8	0.46	24.1	24.5	9.3	0.46	7.2	31.5	16.8	0.46	0.74	46.7
21-3-3-1	0.47	19.2	708	2.2	0.89	34.4	37.8	12.5	0.47	10.8	49.5	20.1	0.47	0.86	88.8
21-3-3-2	0.47	36.2	907	3.2	0.74	26.6	37.6	10.7	0.57	18.4	47	28.2	0.48	1.1	82.2
21-4-4-1	0.45	28	747	2.6	0.62	31.4	31.9	11.1	0.45	12.6	41.6	32.9	0.45	1.2	73.4
21-4-4-2	0.45	48	1075	2.9	0.59	32.6	37.6	13.3	0.5	17.3	51	26.2	0.45	1.1	89.9
21-4-5-1	0.66	25.2	754	3.3	0.7	34.4	42.8	12.7	0.46	13.8	58.9	18	0.46	0.93	106
21-4-5-2	0.42	10.4	759	3.7	0.98	27.2	20.8	11.5	0.5	12.4	31.4	12.9	0.42	0.99	40.9
21-4-6-1	0.44	20.1	772	4.1	0.87	25.7	23.1	11.3	0.51	12.6	31.1	11.7	0.38	0.89	38.6
21-4-6-2	0.4	27.7	750	3.97	0.89	28.8	23.9	12.5	0.59	13.5	31	10.8	0.4	0.86	71.8
22-1-7-1	0.52	36.3	758	3.97	0.61	24.9	25.2	10.8	0.55	11.5	31.2	9.8	0.44	0.85	71.7
22-1-7-2	0.41	24.3	740	4.3	0.96	24.7	21.5	11.9	0.63	11.6	29.8	12	0.41	1.09	36.5
22-1-8-1	0.65	31.6	687	5.1	1.01	24	21.8	10.4	0.41	12.9	31.2	10.1	0.41	0.93	40.6
22-1-8-2	0.42	31.8	978	3.7	0.64	25.5	21.3	11.2	0.65	9.8	30.4	14.4	0.42	0.88	80.2
22-1-9-1	0.39	25.9	749	4.53	0.77	25.1	18.9	8.6	0.47	11.1	29.6	9.34	0.39	0.72	82.2
22-1-9-2	0.4	27.7	665	3.03	0.6	25.3	17.2	8.9	0.6	10.7	33.8	8.35	0.4	0.7	70.6
22-2-10-1	0.37	30.8	621	3.8	0.37	23.9	17.9	9.8	0.53	12	35.2	9.9	0.37	0.65	66.7
22-2-10-2	0.36	12.2	383	2.7	0.36	19.1	23	7.5	0.36	3.4	31	1.04	0.38	0.36	19
22-2-11-1	0.38	7.3	340	3.2	0.38	21.1	19.1	12.9	0.44	2.4	58.3	2.4	0.38	0.46	20.8
22-2-11-2	0.38	9.5	634	2.8	0.38	22.1	19.9	10.3	0.38	7.1	44	6	0.38	0.57	62.2
22-2-12-1	0.41	14.3	554	2.4	0.39	20.8	25.6	9.05	0.39	8.98	50.6	3.63	0.39	0.5	66.4
22-2-12-2	0.38	20.6	754	3.9	0.38	23.1	18.9	8.8	0.4	10.2	57.9	6.2	0.38	0.75	68.4
Mean	1.55	17.77	588.54	3.73	1.56	33.71	32.55	14.57	1.55	8.59	64.65	7.33	1.77	1.68	193.44
Standard Deviation	1.49	8.91	264.22	1.95	1.48	25.48	11.83	6.50	1.49	5.36	68.99	7.80	2.33	1.30	290.35
Upper 95% Confidence Level	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Upper 95% Concentration[2]	4.03	32.57	1027.43	6.98	4.03	76.04	52.20	25.38	4.02	17.50	179.25	20.28	5.63	3.84	675.74

Note:
(1) Analytical results obtained from AES Hawaii, Inc.
(2) Upper 95% Concentration = Mean + Upper 95% Confidence Level x Standard Deviation
95% confidence interval for the concentration mean is used for emission calculation as recommended by EPA
(3) Grey areas indicate non-detect results. Assumed equal to detection lim

TABLE 27: POTENTIAL METALS EMISSIONS CALCULATION FROM ASH HANDLING
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT[1]	lb/hour	ton/year
Total Controlled PM Emissions from Conditioned Ash	0.2817	1.2340
Total Controlled PM Emissions from Bed Ash	0.1205	0.5276
Total Controlled PM Emissions from Fly Ash	0.3614	1.5828
Total Controlled PM Emissions from Ash Handling	0.763585667	3.3445

Metals	Metal Concentrations				Potential Emission[2]		HAP?
	Bed Ash	Fly Ash	Conditioned Ash	Total			
	mg/kg	mg/kg	mg/kg	mg/kg	lbs/hr	tons/year	
Antimony	0.53	3.52	4.03	8.07	6.16E-06	2.70E-05	Yes
Arsenic	26.65	25.87	32.57	85.09	6.50E-05	2.85E-04	Yes
Barium	347.50	1119.60	1027.43	2494.53	1.90E-03	8.34E-03	No
Beryllium	1.48	6.04	6.98	14.49	1.11E-05	4.85E-05	Yes
Cadmium	0.22	3.75	4.03	7.99	6.10E-06	2.67E-05	Yes
Chromium	65.40	55.98	76.04	197.41	1.51E-04	6.60E-04	Yes
Copper	29.30	59.55	52.20	141.05	1.08E-04	4.72E-04	No
Lead	3.21	27.51	25.38	56.09	4.28E-05	1.88E-04	Yes
Mercury	0.03	4.03	4.02	8.08	6.17E-06	2.70E-05	Yes
Molybdenum	3.18	19.35	17.50	40.03	3.06E-05	1.34E-04	No
Nickel	262.00	148.65	179.25	589.90	4.50E-04	1.97E-03	Yes
Selenium	0.39	28.97	20.28	49.64	3.79E-05	1.66E-04	Yes
Silver	0.32	3.82	5.63	9.77	7.46E-06	3.27E-05	No
Thallium	0.47	3.38	3.84	7.69	5.87E-06	2.57E-05	No
Zinc	1659.00	704.43	675.74	3039.16	2.32E-03	1.02E-02	No

Note:
(1) TSP was used to calculate metal emissions
(2) Estimated potential emissions for metals in fugitive PM emissions.

TABLE 28: POTENTIAL EMISSIONS CALCULATION FROM CONDITIONED ASH FRONT END LOADERS TRAVELING ON UNPAVED ROADS TO STOCKPILE LOCATION
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

$E = k(s/12)^a(W/3)^b$ AP 42, 13.2.2 Equation (1a) November 2006 ed.
$E_{ext} = ((365-p)/365*k(s/12)^a(W/3)^b$ AP 42, 13.2.2 Equation (2) November 2006 ed.

where E = Emission factor (lb/vehicle miles traveled)
E_{ext} = annual size-specific emission factor extrapolated for natural mitigation (lb/VMT)
k,a,b,c = constant (lb/VMT)
s = surface material silt content (%)
W = mean vehicle weight (tons)
p = number of days with at least 0.01 inches of precipitation per year

Parameter	Value			Source
	PM-2.5	PM-10	PM-30	
a	0.9	0.9	0.7	AP42, Table 13.2.2-2 (11/06)
b	0.45	0.45	0.45	AP42, Table 13.2.2-2 (11/06)
k	0.15	1.5	4.9	AP42, Table 13.2.2-2 (11/06)
s	5.1			AP42, Table 13.2.2-2 (11/06)
W	28			AES Hawaii, Inc.
p	95			WRCC, see Appendix C

	PM-2.5	PM-10	PM-30
Emission Factor (lb/VMT)	0.19	1.90	7.36
Annual Size Specific Extrapolated for Natural Mitigation (lb/VMT)	0.14	1.40	5.44

	Value	Unit
Production Capacity	21	tph
Facility run time	8,760	hr/year
Loader load	25	ton/trip
Distance traveled by truck	0.100	miles/trip
Max annual capacity	186,800	ton/year
# of trip per year	7,472	trip/year
Total distance VMT	747.2	miles/year

Emissions	PM-2.5		PM-10		PM-30	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Uncontrolled	0.012	0.05	0.120	0.52	0.464	2.033
Controlled(1)	0.004	0.016	0.036	0.157	0.139	0.610

Note:
(1) 70% control factor is applied to account for water spray.

TABLE 29: POTENTIAL EMISSIONS CALCULATION FOR CONDITIONED ASH STOCKPILE
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

INPUT	Value	Unit	Source
Max capacity	186,800	tons/year	AES Hawaii, Inc.

E =k*0.0032*(((U/5)^1.3)/(M/2)^1.4)

where E=Emission Factor (lb/ton) M=moisture content (%)
k=particle size multiplier U=mean wind speed (mph)

	Value	Source
k (TSP)	0.74	AP42,13.2.4 (11/06)
k (PM-10)	0.35	AP42,13.2.4 (11/06)
k (PM-2.5)	0.2	AP42, 13.2.4, (11/06)
U	8.1	WRCC, see Appendix C
M	25	AES Hawaii, Inc.

Contaminant	Emission Factor	Uncontrolled Emission		Control Efficiency	Controlled Emission	
	lb/ton	lb/hr	ton/year		lb/hr	ton/year
TSP	1.29E-04	2.75E-03	1.21E-02	70%	8.26E-04	3.62E-03
PM-10	6.11E-05	1.30E-03	5.71E-03	70%	3.91E-04	1.71E-03
PM-2.5	3.49E-05	7.44E-04	3.26E-03	70%	2.23E-04	9.78E-04

TABLE 30: SUMMARY OF POTENTIAL EMISSIONS FOR CONDITIONED ASH HANDLING SCENARIOS
Ash Handling
AES Hawaii, Inc.
CSP No. 0087-02-C

CONDITIONED ASH HANDLING UNDER NORMAL OPERATION					CONDITIONED ASH HANDLING UNDER ALTERNATIVE OPERATION					DIFFERENCE		
No	Activity	Potential Emissions (tons/year)			No	Activity	Potential Emissions (tons/year)			Potential Emissions (tons/year)		
		TSP	PM10	PM2.5			TSP	PM10	PM2.5	TSP	PM10	PM2.5
1	Direct load to trucks for off site transport	0.0054	0.0026	1.67E-07	1	Conditioned ash is loaded into a loader	0.0054	0.0026	1.67E-07	0.00E+00	0.00E+00	0.00E+00
2	Trucks travelling on paved road to transport conditioned ash off-site	0.0127	0.0025	0.0006	2	Loader travelling on unpaved road from the silo to the yard(1)	0.6098	0.1573	0.0157	0.5971	0.1548	0.0151
					3	Loader unload to storage piles	0.0054	0.0026	1.67E-07	0.0054	0.0026	0.0000
					4	Wind erosion on the conditioned ash pile(2)	0.0036	0.0017	0.0010	0.0036	0.0017	0.0010
	Total (tons per year)	**0.0181**	**0.0051**	**0.0006**		**Total (tons per year)**	**0.6242**	**0.1641**	**0.0167**	**0.6061**	**0.1590**	**0.0161**

CONDITIONED ASH HANDLING UNDER NORMAL OPERATION					CONDITIONED ASH HANDLING UNDER ALTERNATIVE OPERATION					DIFFERENCE		
No	Activity	Potential Emissions (pounds/hour)			No	Activity	Potential Emissions (pounds/hour)			Potential Emissions (pounds/hour)		
		TSP	PM10	PM2.5			TSP	PM10	PM2.5	TSP	PM10	PM2.5
1	Direct load to trucks for off site transport	0.0012	0.0006	0.0003	1	Conditioned ash is loaded into a loader	0.0012	0.0006	0.0003	0.00E+00	0.00E+00	0.00E+00
2	Trucks travelling on paved road to transport conditioned ash off-site	0.0029	0.0006	0.0001	2	Loader travelling on unpaved road from the silo to the yard(1)	0.1392	0.0359	0.0036	0.1363	0.0353	0.0034
					3	Loader unload to storage piles	0.0012	0.0006	0.0003	0.0012	0.0006	0.0003
					4	Wind erosion on the conditioned ash pile(2)	0.0008	0.0004	0.0002	0.0008	0.0004	0.0002
	Total (lb per hour)	**0.0041**	**0.0012**	**0.0005**		**Total (lb per hour)**	**0.1425**	**0.0375**	**0.0045**	**0.1384**	**0.0363**	**0.0040**

NOTE:

1. Calculations were based on maximum capacity of 186,800 tons/year, with one round trip distance from conditioned ash mixer to the yard of 500 fee
2. Assume conditioned ash's moisture content is 25% by weight (Source: AES operator

Table B1a: POTENTIAL ANNUAL EMISSIONS SUMMARY (tons/year)
AES Hawaii, Inc.
CSP No. 0087-02-C

CAS	Criteria Air Pollutants							GHG's		
Contaminant	SO2	NOx	CO	PM total	PM10 total	PM2.5 total	VOC	CO2	CH4	N2O
Coal processing equipment										
Conveyor Transfer				[illegible]	[illegible]	[illegible]				
Coal drops				[illegible]	[illegible]	[illegible]				
Truck Unloading				[illegible]	[illegible]	[illegible]				
Storage piles				[illegible]	[illegible]	[illegible]				
Crushers				[illegible]	[illegible]	[illegible]				
Trucks on Unpaved Roads				[illegible]	[illegible]	[illegible]				
Silo Loading				[illegible]	[illegible]	[illegible]				
Total				[illegible]	[illegible]	[illegible]				
Lime processing equipment										
Trucks on Paved Roads				[illegible]	[illegible]	[illegible]				
Trucks on Unpaved Roads				[illegible]	[illegible]	[illegible]				
Truck Unloading				[illegible]	[illegible]	[illegible]				
Storage pile				[illegible]	[illegible]	[illegible]				
Conveyor Transfer				[illegible]	[illegible]	[illegible]				
Pulverizer (lime crushing)				[illegible]	[illegible]	[illegible]				
Hopper Loading				[illegible]	[illegible]	[illegible]				
Dryer - Fuel Oil Fired	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Storage Tanks										
Fuel oil storage tank							[illegible]			
Total							[illegible]			
Steam Boilers*										
Fuel Oil 2 Fired	*	*	*	*	*	*	*	[illegible]	[illegible]	[illegible]
Solid Fuel	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower										
Cooling Tower				[illegible]	[illegible]	[illegible]				
Total				[illegible]	[illegible]	[illegible]				
Ash handling										
Material Loading				[illegible]	[illegible]	[illegible]				
Separators				[illegible]	[illegible]	[illegible]				
Ash Drops				[illegible]	[illegible]	[illegible]				
Paved Roads				[illegible]	[illegible]	[illegible]				
Alternative Scenario Increase				[illegible]	[illegible]	[illegible]				
Total				[illegible]	[illegible]	[illegible]				
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CAS	Hazardous Air Pollutants: Metals																								
Contaminant	Antimony	Arsenic	Barium (Not HAP, but limited by Permit)	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	1,1,1-Trichloroethane	1,2-Dibromoethane	1,2-Dichloroethane	1,2-Dichloropropane	1,2,4-Trichlorobenzene	2,4-Dinitrophenol	2,4-Dinitrotoluene	1,3-Butadiene	2-Chloroacetophenone	4-Nitrophenol	Acetaldehyde	Acetophenone	Acrolein	Benzene
Coal processing equipment																									
Conveyor Transfer to Silo Loading	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]													
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]													
Lime processing equipment																									
Trucks on Paved Roads to Hopper Loading	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]													
Dryer - Fuel Oil Fired	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Storage Tanks																									
Fuel oil storage tank																									
Total																									
Steam Boilers*																									
Fuel Oil 2 Fired	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Solid Fuel	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible] (4 rows)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower																									
Cooling Tower																									
Total																									
Ash handling																									
Material Loading to Alternative Scenario Increase	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		[illegible]	[illegible]	[illegible]													
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	0	[illegible]	[illegible]	[illegible]													
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

* For Pollutants with Permit limits, tool emissions are set to permit limits and there is no allowance beyond.

Table 21b POTENTIAL ANNUAL EMISSIONS
AES Hawaii, Inc.
CSP No. 0087-01-C

Hazardous Air Pollutants: Other

CAS	100447	117817	75252	74839	75150	56235	7782505	108907	67663	74873	98828		75092	77781	100414	75003	100414	106934	107062	
Contaminant	Benzyl chloride	Bis(2-ethylhexyl)phthalate (DEHP)	Bromoform	Bromomethane	Carbon disulfide	Carbon tetrachloride	Chlorine	Chlorobenzene	Chloroform	Chloromethane	Cumene	Cyanide	Dichloromethane	Dimethyl sulfate	Ethyl benzene	Ethyl chloride	Ethylbenzene	Ethylene dibromide	Ethylene dichloride	Fluorides (Not HAP, but limited by Permit)
Coal processing equipment	Controlled Emissions (tons/year)																			
Conveyor Transfer																				
Coal drops																				
Truck Unloading																				
Storage piles																				
Crushers																				
Trucks on Unpaved Roads																				
Silo Loading																				
Total																				
Lime processing equipment	Controlled Emissions (tons/year)																			
Trucks on Paved Roads																				
Trucks on Unpaved Roads																				
Truck Unloading																				
Storage pile																				
Conveyor Transfer																				
Pulverizer (fine crushing)																				
Hopper Loading																				
Dryer - Fuel Oil Feed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	0
Storage Tanks	Controlled Emissions (tons/year)																			
Fuel oil storage tank																				
Total																				
Steam Boilers*	Controlled Emissions (tons/year)																			
Fuel Oil 2 Feed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	*
Solid Fuel	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower	Controlled Emissions (tons/year)																			
Cooling Tower							[illegible]													
Total							[illegible]													
Ash handling	Controlled Emissions (tons/year)																			
Material Loading																				
Separators																				
Ash Drops																				
Paved Roads																				
Alternative Scenario Increase																				
Total																				
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CAS	50000	110543	7647010	78591	74839	74873	78933	60344	80626	1634044	75092	87865	108952	7723140	123386	123386	100425	7664939	127184	127184	108883
Contaminant	Formaldehyde	Hexane	Hydrogen Chloride	Isophorone	Methyl bromide	Methyl chloride	Methyl ethyl ketone	Methyl hydrazine	Methyl methacrylate	Methyl tert butyl ether	Methylene chloride	Pentachlorophenol	Phenol	Phosphorus	Propanal	Propionaldehyde	Styrene	Sulfuric Acid Mist (Not HAP, but limited by Permit)	Tetrachloroethane	Tetrachloroethylene	Toluene
Coal processing equipment	Controlled Emissions (tons/year)																				
Conveyor Transfer																					
Coal drops																					
Truck Unloading																					
Storage piles																					
Crushers																					
Trucks on Unpaved Roads																					
Silo Loading																					
Total																					
Lime processing equipment	Controlled Emissions (tons/year)																				
Trucks on Paved Roads																					
Trucks on Unpaved Roads																					
Truck Unloading																					
Storage pile																					
Conveyor Transfer																					
Pulverizer (fine crushing)																					
Hopper Loading																					
Dryer - Fuel Oil Feed	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]
Total	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]
Storage Tanks	Controlled Emissions (tons/year)																				
Fuel oil storage tank																					
Total																					
Steam Boilers*	Controlled Emissions (tons/year)																				
Fuel Oil 2 Feed	[illegible]	0	*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*	0	0	[illegible]
Solid Fuel	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower	Controlled Emissions (tons/year)																				
Cooling Tower																					
Total																					
Ash handling	Controlled Emissions (tons/year)																				
Material Loading																					
Separators																					
Ash Drops																					
Paved Roads																					
Alternative Scenario Increase																					
Total																					
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

* For Pollutants with Permit limits, use ...

Table 33c: POTENTIAL ANNUAL EMISSIONS [illegible]
[illegible], Inc.
CP No. [illegible]

CAS	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
					Hazardous Air Pollutants: POM (including PAH)																			Hazardous Air Pollutants: PCB								
Contaminant	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Other Polycyclic organic matter (POM)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Hazardous Air Pollutants: Dioxins & Furans
Coal processing equipment																																
Conveyor Transfer																																
Coal drops																																
Truck Unloading																																
Storage piles																																
Crushers																																
Trucks on Unpaved Roads																																
Silo Loading																																
Total																																
Lime processing equipment																																
Trucks on Paved Roads																																
Trucks on Unpaved Roads																																
Truck Unloading																																
Storage pile																																
Conveyor Transfer																																
Pulverizer (fine crushing)																																
Hopper Loading																																
Dryer - Fuel Oil Fired	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	[illegible]
Total	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	[illegible]
Storage Tanks																																
Fuel oil storage tank																																
Total																																
Steam Boilers*																																
Fuel Oil 2 Fired	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]																																
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

* For Pollutants with Permit limits, [illegible]

Cooling Tower																																
Cooling Tower																																
Total																																
Ash Handling																																
Material Loading																																
Separators																																
Ash Drops																																
Paved Roads																																
Alternative Scenario Increase																																
Total																																
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 11b: POTENTIAL ANNUAL EMISSIONS SUMMARY (lb/hour)
AES Hawaii, Inc.
CSP No. 0087-02-C

CAS										
	Criteria Air Pollutants							GHG's		
	SO2	NOX	630080	PM	PM	PM	VOC	124389	74828	10024972
Contaminant	SO2	NOx	CO	PM Total	PM10 Total	PM2.5 Total	VOC	CO2	CH4	N2O
Coal processing equipment										
Conveyor Transfer				1.7375	0.4530	0.4530				
Coal drops				0.1004	0.0490	0.0093				
Truck Unloading				0.0309	0.0130	0.0130				
Storage piles				0.0901	0.0091	0.0090				
Crushers				0.0149	0.0066	0.0066				
Trucks on Unpaved Roads				1.0543	0.2719	0.0272				
Silo Loading				0.0149	0.0066	0.0066				
Total				2.4579	0.8889	0.5364				
Lime processing equipment										
Trucks on Paved Roads				0.0046	0.0010	0.0002				
Trucks on Unpaved Roads				0.5674	0.0412	0.0041				
Truck Unloading				0.0120	0.0044	0.0044				
Storage pile				0.0001	0.0000	0.0000				
Conveyor Transfer				0.0096	0.0195	0.0195				
Pulverizer (fine crushing)				0.0024	0.0011	0.0011				
Hopper Loading				0.0073	0.0013	0.0013				
Dryer (Max)	2.4089	0.0141	0.1090	0.0129	0.0131	0.0060	0.0064	756.0071	0.0015	0.0090
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	2.4089	0.0141	0.1090	0.2422	0.0494	0.0022	0.0064	756.0071	0.0060	0.0090
Storage Tanks										
Fuel oil storage tank							0.0042			
Total							0.0042			
Steam Boilers										
Boilers (Max)	645.0	236.5	400.4	32.2	32.2	32.2	32.2	671,575.0	35.9	376.3
Coal [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Fuel [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Biomass [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	645.0	2.37E+02	400.4	3.22E+01	3.22E+01	32.2	3.22E+01	6.72E+05	2.69E+01	3.76E+02
Cooling Tower										
Cooling Tower				14.1557	2.73	2.7070				
Total				14.1557	2.73	2.7070				
Ash handling										
Material Loading				0.1240	0.0074	0.0345				
Separators				0.4798	0.2216	0.0276				
Ash Drops				0.0011	0.0006	0.0009				
Paved Roads				0.0079	0.0006	0.0001				
Alternative Scenario Increase				0.1304	0.0962	0.0040				
Total				0.7465	0.2957	0.1364				
Total	647.4089	237.1642	400.5095	39.3021	36.0505	35.0030	32.2130	672,332	36.0133	376

CAS	7440360	7440382	7440393	7440417	7440439	7440473	7440484	7439921	7439965	7439976	7440020	7782492
	Hazardous Air Pollutants: Metals											
Contaminant	Antimony	Arsenic	Barium (not HAP, but limited by Permit)	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium
Coal processing equipment	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Coal processing Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Lime processing equipment	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Dryer (Max)	0	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Lime processing Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Boilers (Max)	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Steam Boilers Total	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ash handling	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]		[illegible]	[illegible]	[illegible]
Ash handling Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	0	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CAS	71556	106934	107062	78875	88062	51285	121142	78933	532274	100027	75070	98862	107028	71432	100447	117817
Contaminant	1,1,1-Trichloroethane	1,2-Dibromoethane	1,2-Dichloroethane	1,2-Dichloropropane	2,4,6-Trichlorophenol	2,4-Dinitrophenol	2,4-Dinitrotoluene	2-Butanone (MEK)	2-Chloroacetophenone	4-Nitrophenol	Acetaldehyde	Acetophenone	Acrolein	Benzene	Benzyl chloride	Bis(2-ethylhexyl)phthalate (DEHP)
Dryer (Max)	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	0
Lime processing Total	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	0
Boilers (Max)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Steam Boilers Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Note:
The maximum lb/hr rate for the dryers and steam boilers is determined by the fuel with the highest hourly emission rate for any given pollutant.

Table 31b: POTENTIAL ANNUAL (tpy)
AES Hawaii, Inc.
CSP No. 0087-02-C

Hazardous Air Pollutants: Max

CAS	75252	74839	75150	56235	7782505	108907	67663	74873	98828		75092	77781	100414	75003	100414	106934	107062		50000	110543
Contaminant	Bromoform	Bromomethane	Carbon disulfide	Carbon tetrachloride	Chlorine	Chlorobenzene	Chloroform	Chloromethane	Cumene	Cyanide	Dichloromethane	Dimethyl sulfate	Ethyl benzene	Ethyl chloride	Ethylbenzene	Ethylene dibromide	Ethylene dichloride	Fluorides (Not HAP but limited by Permit)	Formaldehyde	Hexane
Coal processing equipment	Controlled Emissions (lb/hr)																			
Conveyor Transfer																				
Coal drops																				
Truck Unloading																				
Storage piles																				
Crushers																				
Trucks on Unpaved Roads																				
Silo Loading																				
Total																				
Lime processing equipment	Controlled Emissions (lb/hr)																			
Trucks on Paved Roads																				
Trucks on Unpaved Roads																				
Truck Unloading																				
Storage pile																				
Conveyor Transfer																				
Pulverizer (fine crushing)																				
Hopper Loading																				
Dryer (Max)	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	0	[illegible]	0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	0	[illegible]	0
Storage Tanks	Controlled Emissions (lb/hr)																			
Fuel oil storage tank																				
Total																				
Steam Boilers	Controlled Emissions (lb/hr)																			
Boilers (Max)	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower	Controlled Emissions (lb/hr)																			
Cooling Tower					[illegible]															
Total					[illegible]															
Ash handling	Controlled Emissions (lb/hr)																			
Material Loading																				
Separators																				
Ash Drops																				
Paved Roads																				
Alternative Scenario Increase																				
Total																				
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CAS	7647010	78591	74839	74873	78933	60344	80626	1634044	75092	87865	108952	7723140	123386	123386	100425	7664939	127184	127184	108883	79016	108054
Contaminant	Hydrogen Chloride	Isophorone	Methyl bromide	Methyl chloride	Methyl ethyl ketone	Methyl hydrazine	Methyl methacrylate	Methyl tert butyl ether	Methylene chloride	Pentachlorophenol	Phenol	Phosphorus	Propanal	Propionaldehyde	Styrene	Sulfuric Acid Mist (Not HAP, but limited by Permit)	Tetrachloroethane	Tetrachloroethylene	Toluene	Trichloroethane	Vinyl acetate
Coal processing equipment																					
Conveyor Transfer																					
Coal drops																					
Truck Unloading																					
Storage piles																					
Crushers																					
Trucks on Unpaved Roads																					
Silo Loading																					
Total																					
Lime processing equipment																					
Trucks on Paved Roads																					
Trucks on Unpaved Roads																					
Truck Unloading																					
Storage pile																					
Conveyor Transfer																					
Pulverizer (fine crushing)																					
Hopper Loading																					
Dryer (Max)	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0	0
Storage Tanks																					
Fuel oil storage tank																					
Total																					
Steam Boilers																					
Boilers (Max)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower																					
Cooling Tower																					
Total																					
Ash handling																					
Material Loading																					
Separators																					
Ash Drops																					
Paved Roads																					
Alternative Scenario Increase																					
Total																					
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Note:
The maximum lb/hr rate for the dryer

Table 31b: POTENTIAL ANNUAL EMIS
A(S Hawaii, Inc.
CSP No. 0887-02-C

CAS	75014		83329	208968	120127	56553	[illegible]	[illegible]		191242	92524	218019	53703	206440	86737		91576	91203	85018	129000	POM	2051243	[illegible]	[illegible]	[illegible]	27323188	[illegible]			
			Hazardous Air Pollutants: POM (Including PAH)																			Hazardous Air Pollutants: PCB								Hazardous Air Pollutants: Dioxins & Furans
Contaminant	Vinyl Chloride	Xylenes	Acenaphthene	Acenaphthylene	Anthracene	Benz(a)anthracene	Benzo(a)pyrene	Benzo(b)fluoranthene	[illegible]	Benzo(g,h,i)perylene	Biphenyl	Chrysene	Dibenzo(a,h)anthracene	Fluoranthene	Fluorene	Indeno(1,2,3-cd)pyrene	2-Methylnaphthalene	Naphthalene	Phenanthrene	Pyrene	Other Polycyclic organic matter (POM)	Decachlorobiphenyl	Dichlorobiphenyl	Heptachlorobiphenyl	Hexachlorobiphenyl	Monochlorobiphenyl	Pentachlorobiphenyl	Tetrachlorobiphenyl	Trichlorobiphenyl	
Coal processing equipment																														
Conveyor Transfer																														
Coal drops																														
Truck Unloading																														
Storage piles																														
Crushers																														
Trucks on Unpaved Roads																														
Silo Loading																														
Total																														
Lime processing equipment																														
Trucks on Paved Roads																														
Trucks on Unpaved Roads																														
Truck Unloading																														
Storage pile																														
Conveyor Transfer																														
Pulverizer (fine crushing)																														
Hopper Loading																														
Dryer (Max)	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Total	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	[illegible]
Storage Tanks																														
Fuel oil storage tank																														
Total																														
Steam Boilers																														
Boilers (Max)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cooling Tower																														
Cooling tower																														
Total																														
Ash handling																														
Material Loading																														
Separators																														
Ash Drops																														
Paved Roads																														
Alternative Scenario [illegible]																														
Total																														
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Note:
The maximum lb/hr rate for the dryer

Appendix A – Forms

S-1: Standard Air Pollution Control Permit Application Form
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: AES Hawaii, Inc.

2. Facility Name (if different from the Company):

3. Mailing Address: 91-086 Kaomi Loop

   City: Kapolei State: HI Zip Code: 96707-1883

   Phone Number: (808) 682-5330

4. Name of Owner/Owner's Agent: N/A

   Title: N/A Phone: N/A

   Mailing Address: N/A

   City: N/A State: N/A Zip Code: N/A

5. Plant Site Manager/Other Contact: Steven Barnoski

   Title: Plant Manager Phone: 808-682-3419

   Mailing Address: 91-086 Kaomi Loop

   City: Kapolei State: HI Zip Code: 96707-1883

6. Permit Application Basis: (Check all applicable categories.)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ☐ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ☑ Modification to a Covered Source: ➔ Is Modification? ☑ Significant ☐ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: 0087-02-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ☑ No

9. Type of Source (Check One): ☐ Covered Source ☑ Covered and PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 91-086 Kaomi Loop

City: Kapolei State: HI Zip Code: 96707-1883

UTM Coordinates (meters): East: 592743.8 North: 2355920.4

UTM Zone: 4 UTM Horizontal Datum: ☐ Old Hawaiian ☐ NAD-27 ☑ NAD-83

12. General Nature of Business: Cogeneration/Electric Power and Steam Production

13. Date of Planned Commencement of Construction or Modification: N/A

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ☑ No

15. Type of Organization: ☑ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____)

☐ Other: ____________________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Barnoski (First): Steven (MI): ____

Title: Plant Manager Phone: 808-682-3419

Mailing Address: 91-086 Kaomi Loop

City: Kapolei State: HI Zip Code: 96707-1883

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Steven Barnoski

(Signature): ____________________ Date: 3-26-2018

FOR AGENCY USE ONLY:

File/Application No.: ____________

Island: ____________

Date Received: ____________

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
2. Layout of the facility.
3. Location and identification of the proposed emissions unit on the property.
4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Company Name: AES Hawaii, Inc.

File No.: 0087-02-C

Location: 91-086 Kaomi Loop, Kapolei, HI 96707-1883

(Make as many copies of this page as necessary)

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
N/A		Coal processing		PM Total	PM	2.46E+00	5.37E+00	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		PM10 Total	PM	8.03E-01	1.95E+00	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		PM2.5 Total	PM	5.36E-01	1.01E+00	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Antimony	7440360	1.97E-07	4.30E-07	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Arsenic	7440382	6.88E-06	1.50E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Barium	7440393	8.36E-05	1.83E-04	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Beryllium	7440417	2.46E-07	5.37E-07	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Cadmium	7440439	4.92E-08	1.07E-07	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Chromium		1.47E-05	3.22E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Cobalt	7440484	7.13E-06	1.56E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Lead	7439921	4.92E-06	1.07E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Manganese	7439965	1.72E-05	3.76E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Mercury	7439976	7.37E-08	1.61E-07	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Nickel	7440020	1.97E-05	4.30E-05	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Coal processing		Selenium	7782492	7.37E-07	1.61E-06	592,890	2,355,929	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1A & 1B		Lime processing		SO2	SOX	2.41E+00	1.06E+01	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		NOx	NOX	8.14E-01	3.57E+00	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		CO	630080	1.70E-01	7.43E-01	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		PM Total	PM	2.42E-01	4.90E-03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		PM10 Total	PM	7.65E-02	3.42E-03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		PM2.5 Total	PM	3.22E-02	2.29E-03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		VOC	VOC	6.79E-03	2.97E-02	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		CO2	124389	7.57E+02	3.31E+03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		CH4	74828	1.76E-03	7.73E-03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		N2O	10024972	8.82E-03	3.86E-02	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
1A & 1B		Lime processing		Antimony	7440360	7.76E-08	0.00E+00	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Arsenic	7440382	3.21E-05	8.32E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Barium	7440393	9.13E-07	0.00E+00	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Beryllium	7440417	1.65E-07	6.24E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Cadmium	7440439	2.68E-06	6.24E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Chromium		7.08E-06	6.24E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Cobalt	7440484	5.39E-07	0.00E+00	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Lead	7439921	2.24E-05	1.87E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Manganese	7439965	3.27E-05	1.25E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Mercury	7439976	1.54E-07	6.24E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Nickel	7440020	4.74E-06	6.24E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Selenium	7782492	8.04E-07	3.12E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		1,1,1-Trichloroethane	71556	8.01E-06	3.51E-05	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Benzene	71432	7.26E-06	3.18E-05	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Ethyl benzene	100414	2.16E-06	9.45E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Ethylbenzene	100414	2.16E-06	9.45E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Formaldehyde	50000	1.12E-03	4.90E-03	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Hydrogen Chloride	7647010	8.85E-02	0.00E+00	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Toluene	108883	2.10E-04	9.21E-04	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Xylenes		3.70E-06	1.62E-05	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Acenaphthene	83329	7.16E-07	3.14E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Acenaphthylene	208968	8.58E-09	3.76E-08	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Anthracene	120127	4.14E-08	1.81E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Benz(a)anthracene	56553	1.36E-07	5.96E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Benzo(a)anthracene	56553	1.36E-07	5.96E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Benzo(b,j,k)fluoranthene		5.02E-08	2.20E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Benzo(g,h,i)perylene	191242	7.67E-08	3.36E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Chrysene	218019	8.08E-08	3.54E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Dibenzo(a,h)anthracene	226368	5.67E-08	2.48E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Fluoranthene	206440	1.64E-07	7.19E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
1A & 1B		Lime processing		Fluorene	86737	1.52E-07	6.64E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Indeno(1,2,3,c,d)pyrene		7.26E-08	3.18E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Naphthalene	91203	3.83E-05	1.68E-04	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Phenanthrene	85018	3.56E-07	1.56E-06	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Pyrene	129000	1.44E-07	6.32E-07	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Other Polycyclic organic matter (POM)	POM	7.16E-05	3.13E-04	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
1A & 1B		Lime processing		Dioxins & Furans		1.05E-10	4.61E-10	592,771	2,355,970	3.7	h	1.01	20	16.05	355	N
N/A		Storage Tanks		VOC	VOC	4.19E-03	1.84E-02	592,732	2,355,987	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1		Steam Boilers		SO2	SOX	6.45E+02	2.83E+03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		NOx	NOX	2.37E+02	1.04E+03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		CO	630080	4.08E+02	1.79E+03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		PM Total	PM	3.22E+01	1.41E+02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		PM10 Total	PM	3.22E+01	1.41E+02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		PM2.5 Total	PM	3.22E+01	3.67E+01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		VOC	VOC	3.22E+01	1.41E+02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		CO2	124389	6.72E+05	2.96E+06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		CH4	74828	2.69E+01	2.98E+01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		N2O	10024972	3.76E+02	1.65E+03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Antimony	7440360	1.94E-03	8.48E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Arsenic	7440382	4.41E-02	1.93E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Barium	7440393	0.00E+00	0.00E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Beryllium	7440417	6.70E-02	2.93E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Cadmium	7440439	5.48E-03	2.40E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chromium		2.80E-02	1.22E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Cobalt	7440484	1.08E-02	4.71E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Lead	7439921	5.70E+00	2.50E+01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Manganese	7439965	5.27E-02	2.32E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Mercury	7439976	1.70E-01	7.45E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Nickel	7440020	3.01E-02	1.32E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Selenium	7782492	1.40E-01	6.12E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
1		Steam Boilers		1,1,1-Trichloroethane	71556	3.97E-02	2.92E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		1,2-Dibromoethene	106934	7.05E-02	5.18E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		1,2-Dichloroethane	107062	3.72E-02	2.73E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		1,2-Dichloropropane	78875	4.23E-02	3.11E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		2,4,6-Trichlorophenol	88062	2.82E-05	2.07E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		2,4-Dinitrophenol	51285	2.31E-04	1.70E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		2,4-Dinitrotoluene	121142	3.01E-05	1.32E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		2-Butanone (MEK)	78933	4.19E-02	1.84E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		2-Chloroacetophenone	532274	7.53E-04	3.30E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		4-Nitrophenol	100027	1.41E-04	1.04E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Acetaldehyde	75070	1.06E+00	7.82E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Acetophenone	98862	1.61E-03	7.06E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Acrolein	107028	5.13E+00	3.77E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzene	71432	5.38E+00	3.96E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzyl chloride	100447	7.53E-02	3.30E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Bis(2-ethylhexyl)phthalate (DEHP)	117817	7.85E-03	3.44E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Bromoform	75252	4.19E-03	1.84E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Bromomethane	74839	1.92E-02	7.64E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Carbon disulfide	75150	1.40E-02	6.12E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Carbon tetrachloride	56235	5.77E-02	4.24E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chlorine	7782505	0.00E+00	0.00E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chlorobenzene	108907	4.23E-02	3.11E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chloroform	67663	3.59E-02	2.98E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chloromethane	74873	5.70E-02	2.51E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Cumene	98828	5.70E-04	2.50E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Cyanide		2.69E-01	1.18E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Dichloromethane	75092	3.72E-01	2.73E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
1		Steam Boilers		Dimethyl sulfate	77781	5.16E-03	2.26E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Ethyl benzene	100414	3.97E-02	4.65E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Ethyl chloride	75003	4.52E-03	1.98E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Ethylbenzene	100414	3.97E-02	4.65E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Ethylene dibromide	106934	7.05E-02	5.18E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Ethylene dichloride	107062	3.72E-02	2.73E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Fluoride		2.00E-01	8.76E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Formaldehyde	50000	5.64E+00	4.15E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Hexane	110543	7.20E-03	3.15E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Hydrogen Chloride	7647010	4.30E+00	1.88E+01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Isophorone	78591	6.24E-02	2.73E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl bromide	74839	1.92E-02	7.64E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl chloride	74873	5.70E-02	2.51E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl ethyl ketone	78933	4.19E-02	1.84E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl hydrazine	60344	1.83E-02	8.00E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl methacrylate	80626	2.15E-03	9.42E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methyl tert butyl ether	1634044	3.76E-03	1.65E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Methylene chloride	75092	3.72E-01	2.73E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Pentachlorophenol	87865	6.54E-05	4.80E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Phenol	108952	6.54E-02	4.80E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Phosphorus	7723140	3.46E-02	2.54E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Propanal	123386	8.23E-02	1.84E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Propionaldehyde	123386	8.23E-02	1.84E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Styrene	100425	2.43E+00	1.79E+00	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Sulfuric Acid Mist	7664939	4.10E+00	1.80E+01	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Tetrachloroethene	127184	4.87E-02	3.58E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Tetrachloroethylene	127184	4.87E-02	3.58E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Toluene	108883	1.18E+00	8.68E-01	592,689	2,355,995	86.9	u	3.66	35	369	402	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum *: NAD-83		STACK SOURCE PARAMETERS						
1		Steam Boilers		Trichloroethene	79016	3.84E-02	2.83E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Vinyl acetate	108054	8.17E-04	3.58E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Vinyl Chloride	75014	2.31E-02	1.70E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Xylenes		3.20E-02	2.36E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Acenaphthene	83329	1.17E-03	8.62E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Acenaphthylene	208968	6.41E-03	4.71E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Anthracene	120127	3.84E-03	2.83E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benz(a)anthracene	56553	8.33E-05	6.22E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzo(a)anthracene	56553	8.33E-05	6.22E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzo(a)pyrene	50328	3.33E-03	2.45E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzo(b,j,k)fluoranthene		3.79E-04	2.79E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Benzo(g,h,i)perylene	191242	1.19E-04	8.81E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Biphenyl	92524	1.83E-04	8.00E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Chrysene	218019	4.87E-05	5.04E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Dibenzo(a,h)anthracene	226368	1.17E-05	8.97E-06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Fluoranthene	206440	2.05E-03	1.51E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Fluorene	86737	4.36E-03	3.20E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Indeno(1,2,3,c,d)pyrene		1.11E-04	8.24E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		5-Methyl chrysene	3697243	2.37E-06	1.04E-05	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Naphthalene	91203	1.24E-01	9.16E-02	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Phenanthrene	85018	8.97E-03	6.59E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Pyrene	129000	4.74E-03	3.49E-03	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Other Polycyclic organic matter (POM)	POM	1.14E-04	5.01E-04	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Decachlorobiphenyl	2051243	3.46E-07	2.54E-07	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Dichlorobiphenyl	2051243	9.48E-07	6.97E-07	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Heptachlorobiphenyl	68194161	8.46E-08	6.22E-08	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Hexachlorobiphenyl	8020835	7.05E-07	5.18E-07	592,689	2,355,995	86.9	u	3.66	35	369	402	N

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
1		Steam Boilers		Monochlorobiphenyl	27323188	2.82E-07	2.07E-07	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Pentachlorobiphenyl	31508006	1.54E-06	1.13E-06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Tetrachlorobiphenyl		3.20E-06	2.35E-06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Trichlorobiphenyl		3.33E-06	2.45E-06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
1		Steam Boilers		Dioxins & Furans		4.08E-06	3.07E-06	592,689	2,355,995	86.9	u	3.66	35	369	402	N
N/A		Cooling Tower		PM Total	PM	5.42E+01	2.37E+02	592,520	2,355,955	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Cooling Tower		PM10 Total	PM	2.71E+00	1.19E+01	592,520	2,355,955	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Cooling Tower		PM2.5 Total	PM	2.71E+00	1.19E+01	592,520	2,355,955	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Cooling Tower		Chlorine	7782505	1.04E-03	4.56E-03	592,520	2,355,955	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		PM Total	PM	7.46E-01	3.27E+00	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		PM10 Total	PM	2.94E-01	1.29E+00	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		PM2.5 Total	PM	1.26E-01	5.51E-01	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Antimony	7440360	6.16E-06	2.70E-05	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Arsenic	7440382	6.50E-05	2.85E-04	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Barium	7440393	1.90E-03	8.34E-03	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Beryllium	7440417	1.11E-05	4.85E-05	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Cadmium	7440439	6.10E-06	2.67E-05	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Chromium		1.51E-04	6.60E-04	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Lead	7439921	4.28E-05	1.88E-04	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Mercury	7439976	6.17E-06	2.70E-05	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Nickel	7440020	4.50E-04	1.97E-03	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A		Ash handling		Selenium	7782492	3.79E-05	1.66E-04	592,808	2,356,022	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

File No.: _______

S-6: Application for a Significant Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. Equipment Specifications:
   1. Maximum design capacity.
   2. Fuel type.
   3. Fuel use.
   4. Production capacity.
   5. Production rates.
   6. Raw materials.
   7. Provide any manufacturer's literature.

B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.
   1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.
   2. List all ***new insignificant*** activities in accordance with HAR §11-60.1-82.

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):
   1. Total hours per day, per week, and/or per month.
   2. Total hours per year.
   3. If operation is seasonal or irregular, describe.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:
   1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement.
   2. Explanation of all proposed exemptions from any applicable requirements.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable.

G. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96.

H. For ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

I. For ***new*** covered sources or ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

J. Provide the following for compliance purposes:
   1. A Compliance Plan, Form C-1.
   2. A Compliance Certification, Form C-2.

II. Submit an application fee according to the Application Fee Schedule in <u>the Instructions for Applying for an Air Pollution Control Permit</u>.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. Results of source emissions testing, ambient air quality monitoring, or both.

C. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete:
   1. For the requirements of subchapter 7, thirty days after receipt of the application.
   2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
   3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to **VI.A.2** above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

IX. 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 the draft significant

modification to the covered source in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

File No.: 0087-02-C

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ☑ YES {If YES, complete items a and c below}

   ☐ NO {If NO, complete items a, b, and c below}

   a. Identify all applicable requirement(s) for which compliance is achieved.

   HAR §11-59 Ambient Air Quality Standards
   HAR §11-60.1 Subchapter 1 General Requirements
   HAR §11-60.1 Subchapter 2 General Prohibitions
   HAR §11-60.1 Subchapter 5 Covered Sources
   HAR §11-60.1 Subchapter 5 Covered Sources
   HAR §11-60.1 Subchapter 6 Fees for Noncovered Sources, Covered Sources, and Agricultural Burning
   HAR §11-60.1 Subchapter 7 Prevention of Significant Deterioration Review
   HAR §11-60.1 Subchapter 8 Standards of Performance for Stationary Sources
   HAR §11-60.1 Subchapter 9 Hazardous Air Pollutant Sources
   HAR §11-60.1 Subchapter 10 Field Citations
   HAR §11-60.1 Subchapter 11 Greenhouse Gas Emissions
   40 CFR 50 National Primary and Secondary Air Quality Standards
   40 CFR 52.21 Prevention of Significant Deterioration of Air Quality
   40 CFR 60 New Source Performance Standards
   40 CFR 63 National Emission Standards for Hazardous Air Pollutants
   40 CFR 64 Compliance Assurance Monitoring
   40 CFR 68 Chemical Accident Prevention Provisions
   40 CFR 70 State Operating Permit Program
   40 CFR 98 Mandatory Greenhouse Gas Reporting

   Provide a statement that the source is in compliance and will continue to comply with all such requirements.
   AES Hawaii, Inc. is in compliance, and will continue to comply with all applicable state and federal requirements.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved.
   N/A

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

Description of Remedial Action	Expected Date of Completion
N/A	

c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance?
GHG facility-wide cap (HAR Section 11-60.1-204(c)	1/1/2020	N/A

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance
AES will comply with the facility-wide GHG Emissions Cap	1/1/2020

Provide a statement that the source on a timely basis will meet all these applicable requirements:

The source will meet the applicable requirements on a timely basis

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

Description of Remedial Action and Explanation	Expected Date of Completion
N/A	

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A (less than or equal to 6 months) Beginning Date: ____________

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved
N/A	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

N/A

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Barnoski (First): Steven (MI): ______

Title: Plant Manager Phone: 808-682-3419

Mailing Address: 91-086 Kaomi Loop

City: Kapolei State: HI Zip Code: 96707-1883

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Steven Barnoski

(Signature): ____________ Date: 3-26-2018

Facility Name: AES Hawaii, Inc.

Location: 91-086 Kaomi Loop, Kapolei, Hi

Permit Number: 0087-02-C

FOR AGENCY USE ONLY

File/Application No.: ____________

Island: ____________

File No.: 0087-02-C

C-2: Compliance Certification

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Barnoski (First): Steven (MI): ______

Title: Plant Manager Phone: 808-682-3419

Mailing Address: 91-086 Kaomi Loop

City: Kapolei State: HI Zip Code: 96707-1883

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Steven Barnoski

(Signature): Ste Bk Date: 3-26-2018

Facility Name: AES Hawaii, Inc.

Location: 91-086 Kaomi Loop, Kapolei, HI 96707-1883

Permit Number: 0087-02-C

FOR AGENCY USE ONLY
File/Application No.: ______
Island: ______
Date Received: ______

Complete the following information for ***each*** applicable requirement that applies to ***each*** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

   Frequency of Submittal: Annually Beginning Date: March 31, 2011

2. Emissions Unit No./Description: Boiler, Coal/Fuel Processing, Limestone Processing, ash handling, tank

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   HAR §11-59 Ambient Air Quality Standards
   HAR §11-60.1 Subchapter 1 General Requirements
   HAR §11-60.1 Subchapter 2 General Prohibitions
   HAR §11-60.1 Subchapter 5 Covered Sources
   HAR §11-60.1 Subchapter 5 Covered Sources
   HAR §11-60.1 Subchapter 6 Fees for Noncovered Sources, Covered Sources, and Agricultural Burning
   HAR §11-60.1 Subchapter 7 Prevention of Significant Deterioration Review
   HAR §11-60.1 Subchapter 8 Standards of Performance for Stationary Sources
   HAR §11-60.1 Subchapter 9 Hazardous Air Pollutant Sources
   HAR §11-60.1 Subchapter 10 Field Citations
   HAR §11-60.1 Subchapter 11 Greenhouse Gas Emissions
   40 CFR 50 National Primary and Secondary Air Quality Standards
   40 CFR 52.21 Prevention of Significant Deterioration of Air Quality
   40 CFR 60 New Source Performance Standards
   40 CFR 63 National Emission Standards for Hazardous Air Pollutants
   40 CFR 64 Compliance Assurance Monitoring
   40 CFR 68 Chemical Accident Prevention Provisions
   40 CFR 70 State Operating Permit Program
   40 CFR 98 Mandatory Greenhouse Gas Reporting

4. Compliance status:

   a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

      ☑ YES ☐ NO

   b. If YES, will compliance be continuous or intermittent?

      ☑ Continuous ☐ Intermittent

   c. If NO, explain:

      N/A

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

See Attached Table

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See Attached Table

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

☑ YES ☐ NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

AES Hawaii, Inc. will continue to submit the Compliance Certification Form annually to comply with the compliance certification requirements. When enhanced monitoring requirements become applicable, AES Hawaii, Inc. will comply with the applicable requirements.

c. If NO, describe below which requirements will not be met:

N/A

Table 1: Methods to Determine Compliance

Form C-2

Equipment/Material	Requirements	Method to Determine Compliance	Detailed Description of Method
CFB Boilers			
Coal	- SO_2 Emissions < 645 lb/hr - SO2 Emissions < 1.2 lb/MMBtu	Continuous Emission Monitoring System	-CEMs system will monitor SO2. If exceedance, the site will immediately limit the feed rate of coal with sulfur content >1.5%-wt until back in compliance. -75% to 90% reduction in SO2 emissions by limestone injection -flue gas captured by the boiler baghouses
Fuel Oil #2	- sulfur content < 0.5 %-wt	Analyze sulfur content	- use ASTM D6405 or equivalent methods - obtain certificate of analysis from suppliers
Biomass (wood)	- heat input < 215 MMBtu/hr	Analyze Biomass	- obtain monthly sampling to determine HHV of the fuel
Biomass (wood)	- HCl < 0.002 lb/MMBtu	Analyze Biomass	- obtain quarterly ultimate analysis with chlorine content of the fuel
Biomass (wood)	- HCl < 0.002 lb/MMBtu	Analyze Biomass	- Records shall be maintained on vendors or sources furnishing wood fuel for use in the boilers
Biomass (wood)	- HCl < 0.002 lb/MMBtu	Emissions	- Annual performance test utilizing EPA Test Methods 1-4 and 26 or 26A for the emissions of HCl.
Coal/TDF/Biomass	- TDF/coal < 215,000 lb/hr - TDF < 7.5 ton/hr - Biomass < 20 ton/hr	Fuel measurement system	- continuous measurement and recording of coal, TDF, and biomass consumption
Spec Used Oil	- spec used oil < 3,000,000 gal/yr	Non-resetting flow meter	- continuous measurement and recording of spec used oil flow - monthly records of meter readings and fuel usage
Spec Used Oil	- Arsenic < 5 ppm - Cadmium < 2 ppm - Chromium < 10 ppm - Lead < 100 ppm - Total Halogens < 1000 ppm - Sulfur < 0.5%-wt - Flash Point > 100oF - PCB <2 ppm	Analyze spec used oil	- analyze used oil generated by the facility for each batch - obtain analysis reports from suppliers
Baghouse	- pressure drop between 1" to 9" water	Pressure drop meter	- continuous reading during operation - monitor at least once daily

Equipment/Material	Requirements	Method to Determine Compliance	Detailed Description of Method
Air Pollution Control Equipment	- SO2 < 645.0 lb/hr - NOx < 236.5 lb/hr - Opacity < 20% - HCl – SO2 as surrogate	Continuous Emission Monitoring System	- operate CEMS and record data during all periods of operation - conduct required performance specification tests and meet subject QA requirement
Coal Processing			
Baghouse	- pressure drop between 1" to 7" water	Pressure drop meter	- continuous reading during operation - monitored at least once daily
Baghouse	- PM emission < 0.3 lb/hr - Opacity < 7%	Visual Emissions Readings	-monthly VE observations - records maintained
Limestone Processing			
Fuel Oil #2	- sulfur content < 0.5 %-wt	Analyze sulfur content	- use ASTM D6428 or equivalent methods - obtain certificate of analysis from suppliers
Spec Used Oil	- spec used oil < 250,000 gal/yr	Non-resetting flow meter	- continuous measurement and recording of spec used oil - monthly records of meter readings and fuel usage
Spec Used Oil	- Chromium < 10 ppm - Lead < 100 ppm - Total Halogens < 1000 ppm - Sulfur < 0.5%-wt - Flash Point > 100oF - PCB < 2 ppm	Analyze spec used oil	- analyze used oil generated by the facility for each batch - obtain analysis reports from suppliers
Baghouse	- pressure drop between 1" to 7" water	Pressure drop meter	- continuous reading during operation - monitored at least once daily
Baghouse	- PM emission < 0.04 lb/hr - Opacity < 7%	Visual Emissions	- monthly VE observations - records maintained
Cooling Tower			
Emission	- annual mean TDS < 44,000 mg/L - Chlorine < 1 mg/L	Analyze water	- analyze blowdown water monthly for TDS - analyze water for Chlorine
General			
Records Maintain records on inspections, maintenance, and repairs for all equipment. Maintain records on fuel usage, delivery receipts, and fuel sample analysis results. Maintain records on emissions data and cooling tower blowdown water analysis test results.			

Appendix B – GHG Emissions Reduction Plan

February 28, 2018

Marianne Rossio, P.E
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 Submittal

Dear Ms. Rossio,

AES Hawaii, Inc. (AESHI) is submitting the attached Greenhouse Gas Emission Reduction Plan (ERP) required by (HAR) §11-60.1-204, to meet the February 28, 2018 deadline. This is a joint ERP between AESHI and the Hawaiian Electric Companies (HECO) and reflects a partnership agreement between the parties. A standalone ERP was submitted to DOH on December 1, 2016, however, this joint ERP is AESHI's preferred approach.

In accordance with HAR§11-60.1-204(d)(1), AESHI established the baseline facility-wide GHG emissions based on calendar year 2010 emissions. AESHI did not have a continuous emission monitoring system for the calculation of GHG emissions from the boilers, so 2010 calculations are based on 40 CFR Part 98 emission factors and 2010 annual material consumption rates for both the boilers and the limestone dryers. In order to assure that the same calculation methodology was used to compare future years' emissions to the baseline, the emission cap for 2020 is also based on 40 CFR Part 98 emission factors and annual material consumption rates.

If you have any questions, please call Priya Kumar at 682-3409 or e-mail at priya.kumar@aes.com.

Sincerely,

for

Steven Barnoski
Plant Manager
AES Hawaii, Inc.

enclosure

Certification Statement:

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

for

Steven Barnoski, Plant Manager

Date: 2.28.18

AES United States

AES Hawaii, Inc.

Greenhouse Gas Emission Reduction Plan

February 28, 2018

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B. Calendar Year 2010 Annual Baseline Emissions Calculations

C. GHG Reduction Partnership

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, Inc. (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. 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	1,228,726
Total Partnership	8,311,960

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 % removal	Expected GHG Emission Rate tons CO_2e/yr	Expected GHG Emission Rate lbs CO_2e/kWh-g	Expected Emission Reduction tons CO_2e/yr
Pelletized Biomass Co-firing @ 25% Heat Input	16.0%	**1,388,775**	1.680	264,529
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,444,752**	1.747	208,551
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,548,891**	1.873	104,413
Heat Rate Improvement Combination (All Options)	3.1%	**1,601,638**	1.937	51,666
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,618,653**	1.958	34,651
Turbine Upgrade	1.25%	**1,632,637**	1.974	20,666
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,636,771**	1.979	16,533
Air Heater Temperature Reduction	0.75%	**1,640,904**	1.984	12,400
Sootblower Improvements	0.70%	**1,641,730**	1.985	11,573
DCS Upgrade	0.50%	**1,645,037**	1.989	8,267
VFD Motors	0.30%	**1,648,344**	1.993	4,960
Baseline Emissions	--	**1,653,304**	1.999	--

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	$293	N/A	N/A
DCS Upgrade	$226	N/A	N/A
Sootblower Improvements	$52	N/A	N/A
Air Heater Temperature Reduction	$1,823	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$124	N/A	N/A
Turbine Upgrade	$404	N/A	N/A
Fuel Oil Co-firing @ 10% Heat Input	$534	Increased hazardous air pollutant (HAP) emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$589	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$532	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$178	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$128	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 $52 per ton (sootblowing improvements) to $1,823 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	6,982,040 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 = 10, 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	1,228,726
Total Partnership	8,311,960

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 $52 per ton (sootblowing improvements) to $1,823 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 $128 per ton to $534 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.

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[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	6,982,040 short tons/yr	1,691,605 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

AES United States

AES HAWAII, INC.

GREENHOUSE GAS EMISSION REDUCTION PLAN

DECEMBER 1, 2016
PROJECT NO. 13467-001

PREPARED BY

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000
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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)	1,639,558	0	27.8	8,293	191	4,780	1,652,631
Limestone Dryers	821.6	0	0.0067	1.99	0.033	0.83	824.4
Facility-Wide Total	1,640,379	0	27.8	8,295	191	4,781	1,653,455

Note 1. CO_2e emissions calculated based on GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, N_2O = 298, CH_4 = 25).

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%	**1,388,903**	1.680	264,552
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,444,881**	1.747	208,574
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,549,038**	1.873	104,417
Heat Rate Improvement Combination (All Options)	3.1%	**1,601,784**	1.937	51,670
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,618,800**	1.958	34,655
Turbine Upgrade	1.25%	**1,632,787**	1.975	20,668
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,636,920**	1.980	16,535
Air Heater Temperature Reduction	0.75%	**1,641,054**	1.985	12,401
Sootblower Improvements	0.70%	**1,641,881**	1.986	11,574
DCS Upgrade	0.50%	**1,645,188**	1.990	8,267
VFD Motors	0.30%	**1,648,495**	1.994	4,960
Baseline Emissions	--	**1,653,455**	2.000	--

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	$293	--	N/A	N/A
DCS Upgrade	$226	$126	N/A	N/A
Sootblower Improvements	$52	--	N/A	N/A
Air Heater Temperature Reduction	$1,823	$26,608	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$124	$293	N/A	N/A
Turbine Upgrade	$404	$1,523	N/A	N/A
Fuel Oil Co-firing @ 10% Heat Input	$519	$689	Increased hazardous air pollutant (HAP) emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$589	$731	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$517	$446	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$178	$43	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$128	$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 $52 per ton (sootblowing improvements) to $1,823 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	1,653,455 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:

$$\begin{aligned}\textit{Facility-Wide Baseline Emissions (tpy } CO_2e) = \; & \textit{Facility-Total Baseline GHG Emissions (tpy } CO_2e) - \\ & \textit{Facility Baseline Biogenic } CO_2 \textit{ Emissions (tpy } CO_2)\end{aligned}$$

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)	1,639,558	0	27.8	8,293	191	4,780	1,652,631
Limestone Dryers	821.6	0	0.0067	1.99	0.033	0.83	824.4
Facility-Wide Total	1,640,379	0	27.8	8,295	191	4,781	1,653,455

Note 1. CO_2e emissions calculated based on GWP values from Table A-1 to Subpart A of Part 98 (i.e., CO_2 = 1, N_2O = 298, CH_4 = 25).

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

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[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.

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

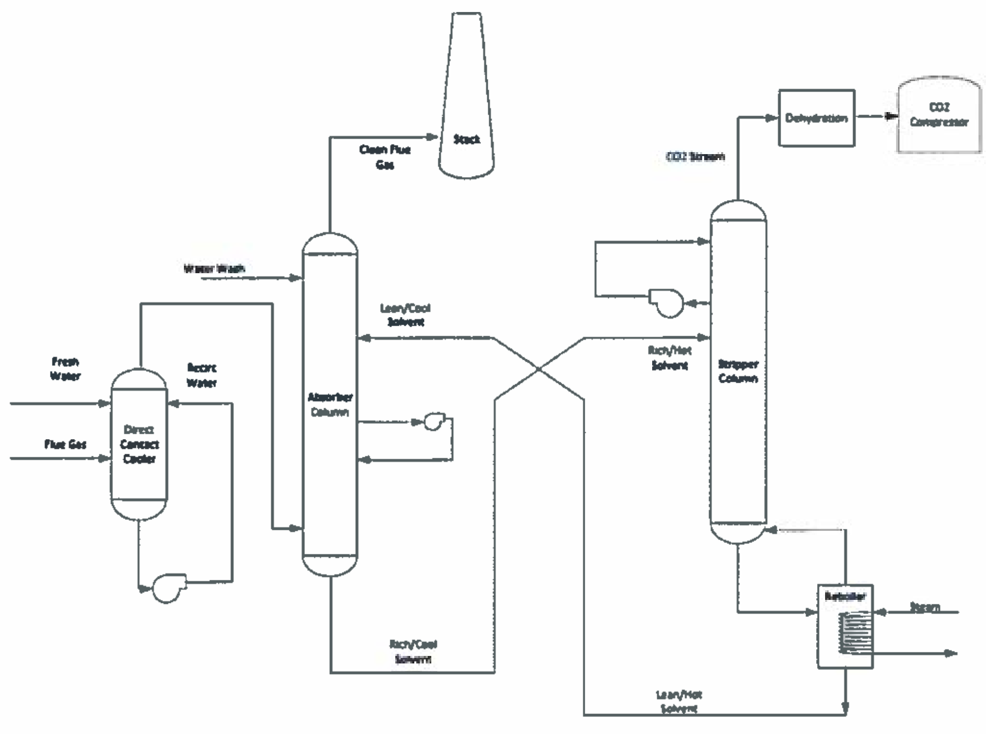
5.1.2 Step 2: Technical Feasibility of Potential GHG Control Options

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*

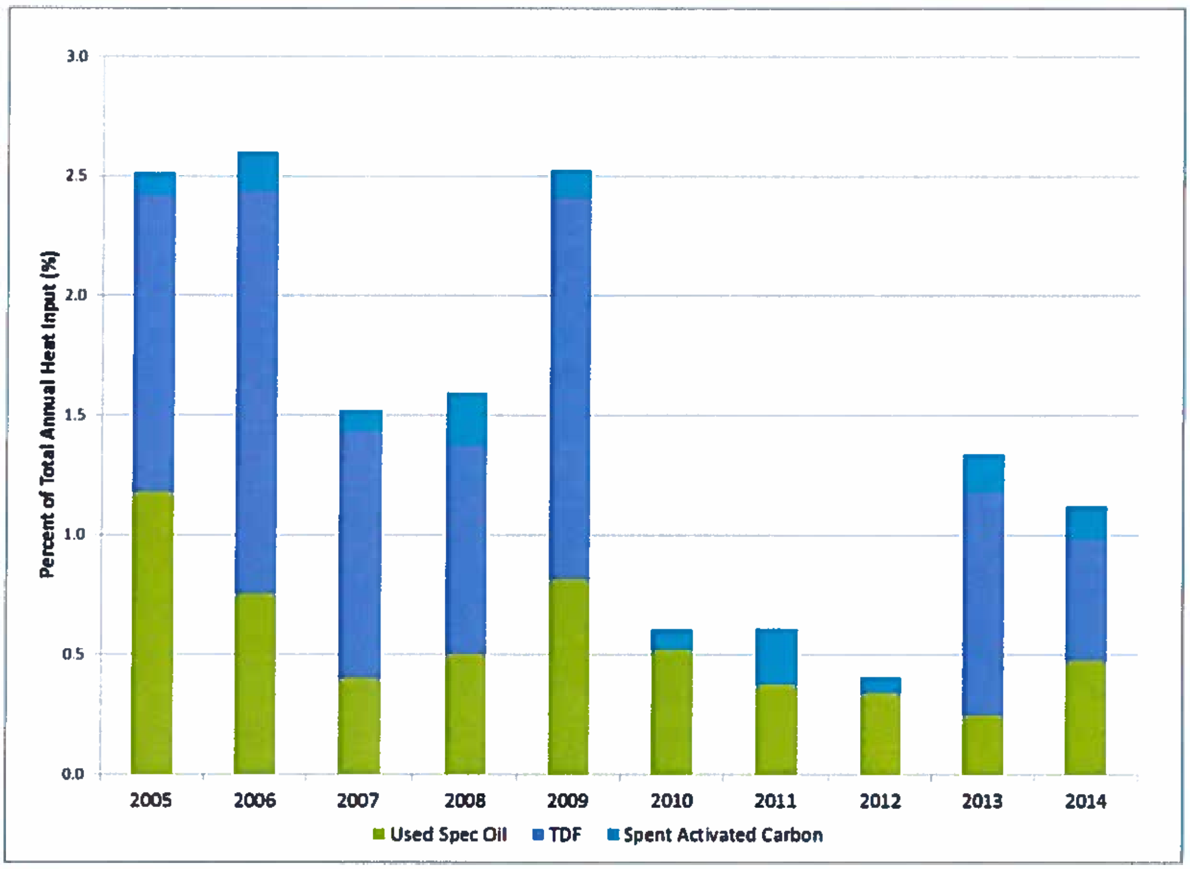
CFB boilers tend to be very robust when it comes to the type of fuel that is possible to fire, due to the nature of the combustion process and the long residence time the fuel has in the boiler. Boilers A and B currently fire a fuel blend consisting mostly of coal, but also small amounts of spent activated 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

[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 benefit from 0.75% CO_2 reduction, on average, if the air heater outlet temperatures were reduced to 250°F.

[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.

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.

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

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

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 % 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%	**1,388,903**	1.680	264,552
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	**1,444,881**	1.747	208,574
Fuel Oil Co-firing @ 30% Heat Input	6.3%	**1,549,038**	1.873	104,417
Heat Rate Improvement Combination (All Options)	3.1%	**1,601,784**	1.937	51,670
Fuel Oil Co-firing @ 10% Heat Input	2.1%	**1,618,800**	1.958	34,655
Turbine Upgrade	1.25%	**1,632,787**	1.975	20,668
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	**1,636,920**	1.980	16,535
Air Heater Temperature Reduction	0.75%	**1,641,054**	1.985	12,401
Sootblower Improvements	0.70%	**1,641,881**	1.986	11,574
DCS Upgrade	0.50%	**1,645,188**	1.990	8,267
VFD Motors	0.30%	**1,648,495**	1.994	4,960
Baseline Emissions	--	**1,653,455**	2.000	--

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	$1,452,100	4,960	**$293**	--
DCS Upgrades	$1,867,300	8,267	**$226**	$126
Sootblower Improvements	$605,300	11,574	**$52**	--
Air Heater Temperature Reduction	$22,602,600	12,401	**$1,823**	$26,608
Heat Rate Improvement Combination (Low Cost)	$2,057,300	16,535	**$124**	$293
Turbine Upgrade	$8,352,400	20,668	**$404**	$1,523
Fuel Oil Co-firing @ 10% Heat Input	$17,989,500	34,655	**$519**	$689
Heat Rate Improvement Combination (All Options)	$30,432,100	51,670	**$589**	$731
Fuel Oil Co-firing @ 30% Heat Input	$53,980,800	104,417	**$517**	$446
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$37,122,500	208,574	**$178**	$43
Pelletized Biomass Co-firing @ 25%	$33,865,300	264,552	**$128**	$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 $52 per ton (sootblowing) to $1,823 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	$293	--	N/A	N/A
DCS Upgrade	$226	$126	N/A	N/A
Sootblower Improvements	$52	--	N/A	N/A
Air Heater Temperature Reduction	$1,823	$26,608	N/A	N/A
Heat Rate Improvement Combination (Low Cost)	$124	$293	N/A	N/A
Turbine Upgrade	$404	$1,523	N/A	N/A
Fuel Oil Co-firing @10% Heat Input	$519	$689	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Heat Rate Improvement Combination (All Options)	$589	$731	N/A	N/A
Fuel Oil Co-firing @ 30% Heat Input	$517	$446	Increased HAP emissions, change fly ash composition, delivery-related emissions	N/A
Local Eucalyptus Biomass Co-firing – 150,000 TPY	$178	$43	Increased HAP emissions, change fly ash composition, delivery-related emissions	Increased unit heat rate
Pelletized Biomass Co-firing @ 25% Heat Input	$128	$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 $52 per ton (sootblowing improvements) to $1,823 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 $128 per ton to $519 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 $52 per ton (sootblowing improvements) to $1,823 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	1,653,455 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

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(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:

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

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		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		10,570		205.6		3.5E-03	2.4E-02	207.3	1,616,410		27.7	8,262	190.6	4765.4	1,629,438
	Fuel Oil[5]		74,490		138,000	163.1		1.3E-03	6.6E-03	163.6	838.1		0.0068	2.03	0.034	0.85	840.9
	TDF[6]	0		14,000		189.5		9.3E-03	7.1E-02	194.1	0		0	0	0	0	0
	Spent Activated Carbon[7]	751		15,000		250.6		3.5E-03	2.4E-02	252.3	2,823.0		0.04	11.84	0.27	6.83	2,841.6
	Spec. Used Oil[8]		609,090		138,000	163.1		1.3E-03	6.6E-03	163.6	6,852.6		0.056	16.6	0.28	6.95	6,876.1
	Limestone	28,742					0.440				12,634						12,634.0
	Biomass	0				0						0					
	Total, Boilers A and B										1,639,558	0	28	8,293	191	4,780	1,652,631
Limestone Dryers	Fuel Oil		73,027		138,000	163.1		1.3E-03	6.6E-03	163.6	821.60		0.0067	1.9862	0.033	0.83	824.4
Facility-Wide Total											1,640,379	0	28	8,295	191	4,781	1,653,455

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 = 298, CH_4 = 25).

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.

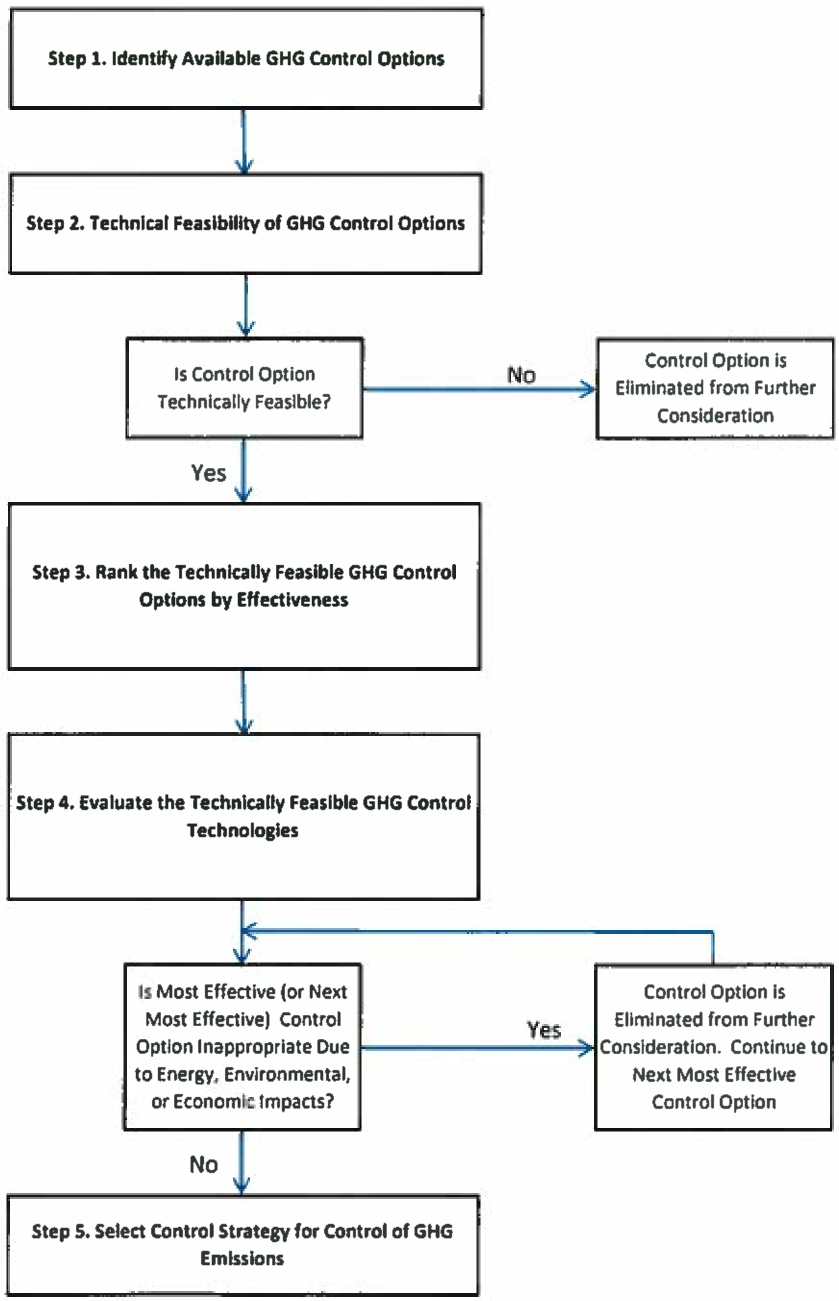
Note 6. TDF delivery system has a variable speed drive and weigh scale for delivery to the coal silos. Since the TDF is delivered to the boilers via the same gravimetric feeders that deliver the coal, this is corrected for in the final coal feed values.

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.

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%	1,388,903	1.680	264,552
Local Eucalyptus Biomass Co-firing - 150,000 TPY	12.6%	1,444,881	1.747	208,574
Fuel Oil Co-firing -30% Heat Input	6.3%	1,549,038	1.873	104,417
Heat Rate Improvement Combination (All Options)	3.1%	1,601,784	1.937	51,670
Fuel Oil Co-firing -10% Heat Input	2.1%	1,618,800	1.958	34,655
Turbine Upgrade	1.25%	1,632,787	1.975	20,668
Heat Rate Improvement Combination (Lowest Cost Options)	1.00%	1,636,920	1.980	16,535
Air Heater Temperature Reduction	0.75%	1,641,054	1.985	12,401
Sootblower Improvements	0.70%	1,641,881	1.986	11,574
DCS Upgrade	0.50%	1,645,188	1.990	8,267
VFD Motors	0.30%	1,648,495	1.994	4,960
Baseline Emissions	0	1,653,455	2.000	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	1,653,455	-	--	--	--	--		
VFD Motors	1,648,495	4,960	$6,095,000	$1,318,000	$134,000	$1,452,000	$293	
DCS Upgrade	1,645,188	8,267	$8,100,000	$1,752,000	$115,300	$1,867,300	$226	$126
Sootblower Improvements	1,641,881	11,574	$2,604,000	$563,000	$42,300	$605,300	$52	
Air Heater Temperature Reduction	1,641,054	12,401	$96,521,000	$20,879,000	$1,723,600	$22,602,600	$1,823	$26,608
Heat Rate Improvement Combination (Lowest Cost Options)	1,636,920	16,535	$8,700,000	$1,882,000	$175,300	$2,057,300	$124	$293
Turbine Upgrade	1,632,787	20,668	$38,598,000	$8,349,000	$4,400	$8,353,400	$404	$1,523
Fuel Oil Co-firing -10% Heat Input	1,618,800	34,655	$1,053,000	$228,000	$17,761,500	$17,989,500	$519	$689
Heat Rate Improvement Combination (All Options)	1,601,784	51,670	$132,121,000	$28,580,000	$1,852,100	$30,432,100	$589	$731
Fuel Oil Co-firing -30% Heat Input	1,549,038	104,417	$2,397,600	$519,000	$53,461,800	$53,980,800	$517	$446
Local Eucalyptus Biomass Co-firing - 150,000 TPY	1,444,881	208,574	$30,780,000	$6,658,000	$30,464,500	$37,122,500	$178	$43
Pelletized Biomass Co-firing - 25%	1,388,903	264,552	$21,060,000	$4,556,000	$29,309,300	$33,865,300	$128	$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)	1,653,455
Post HRI CO2 Emissions (tpy)	1,648,495
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	

GHG Cost Evaluation
Heat Rate Improvements

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

	INPUT
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,653,455**
Post HRI CO2 Emissions (tpy)	**1,645,188**
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		
		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	-$292,656	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**	

GHG Cost Evaluation
Heat Rate Improvements

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 CO2 Emissions (tpy)	1,653,455
Post HRI CO2 Emissions (tpy)	1,641,881
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	

GHG Cost Evaluation
Heat Rate Improvements

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 CO_2 Emissions (tpy)	1,653,455
Post HRI CO_2 Emissions (tpy)	1,641,054
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		
Fuel Cost Differential	-$439,000	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	-$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	

GHG Cost Evaluation
Heat Rate Improvements

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

	INPUT
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,653,455**
Post HRI CO2 Emissions (tpy)	**1,636,920**
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 CO2 Emissions (tpy)	1,653,455
Post HRI CO2 Emissions (tpy)	1,632,787
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 based 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). Penalty 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
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,653,455
Post Fuel Oil Co-Firing CO2 Emissions (tpy)	1,618,800
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**	

GHG Cost Evaluation
Heat Rate Improvements

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

	INPUT
	2 x 100 MW-gross
Case	CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO_2 Emissions (tpy)	1,653,455
Post HRI CO_2 Emissions (tpy)	1,601,784
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 $570/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 turbine and 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 Differential	$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	

GHG Cost Evaluation
Fuel Oil Co-Firing

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)	**1,653,455**
Post Fuel Oil Co-Firing CO2 Emissions (tpy)	**1,549,038**
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**	

GHG Cost Evaluation
Biomass Co-Firing

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

	INPUT
Case	2 x 100 MW-gross CFB Boilers
Annual Average Heat Input (mmBtu/yr)	15,837,251
Baseline CO2 Emissions (tpy)	1,653,455
Post Biomass Co-Firing CO2 Emissions (tpy)	1,444,881
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
Case	**2 x 100 MW-gross CFB Boilers**
Annual Average Heat Input (mmBtu/yr)	**15,837,251**
Baseline CO2 Emissions (tpy)	**1,653,455**
Post Biomass Co-Firing CO2 Emissions (tpy)	**1,388,903**
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 $196.49/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

Appendix C

GHG Reduction Partnership

Baseline CO_2e Emissions and 2019 CO_2e Permit Limits

Company	Covered Source	Baseline CO_2e Emissions (metric tpy)	Baseline CO_2e Emissions (tpy)	Proposed 2019 CO_2e Reduction (%)	Proposed 2019 CO_2e Reduction (tpy)	Proposed 2019 CO_2e Limit (tpy)
Hawaiian Electric (HE)	Kahe	2,518,411	2,776,073	23.0%	638,218	2,137,855
	Waiau	974,643	1,074,360	24.6%	264,520	809,840
	Honolulu	121,208	133,609	100.0%	133,609	0
	CIPGS	13,559	14,946	-260.2%	-38,896	53,842
HE Total		**3,627,821**	**3,998,988**	**24.9%**	**997,451**	**3,001,537**
Maui Electric (ME)	Kahului	209,414	230,839	32.9%	75,909	154,930
	Maalaea	562,012	619,512	25.6%	158,764	460,748
	Palaau	25,615	28,236	6.1%	1,731	26,505
ME Total		**797,041**	**878,587**	**26.9%**	**236,404**	**642,183**
Hawaiian Electric Light (HEL)	Kanoelehua-Hill	202,106	222,783	22.4%	49,998	172,785
	Keahole	173,623	191,387	-26.8%	-51,285	242,672
	Puna	90,438	99,691	68.1%	67,883	31,808
	Shipman	9,246	10,192	100.0%	10,192	0
HEL Total		**475,413**	**524,053**	**14.7%**	**76,788**	**447,265**
HE/ME/HEL Total		**4,900,275**	**5,401,629**	**24.3%**	**1,310,644**	**4,090,985**
AES Hawaii		**1,525,526**	**1,681,605**	**-0.6%**	**-10,000**	**1,691,605**
HEP		**165,992**	**182,975**	**16.0%**	**29,276**	**153,699**
KPLP		**948,689**	**1,045,751**	**0.0%**	**0**	**1,045,751**
Partnership Total		**7,540,482**	**8,311,960**	**16.00%**	**1,329,920**	**6,982,040**

Notes:
1. Excludes biogenic CO2 emissions.
2. AES baseline is 2010 basis, adjusted as agreed with DOH.
3. KPLP baseline is 2009 basis adjusted for CEMS correction factor, as agreed with DOH.
4. All other baselines are 2010 actual emissions as reported in EPA's e-GGRT reporting system, except for HE CIPS and HEL Shipman.
   For calendar year 2010 CIPGS and Shipman emissions were lower than the 25,000 metric tpy reporting threshold.
   CIPGS and Shipman emissions are calculated as specified by EPA's GHG Mandatory Reporting Rule.
5. CIPGS is designated as the Main CSP for the Hawaiian Electric Companies' GHG Emissions Reduction Plan.

Appendix C – Equipment Specification Sheets

Attachment C-1 – Mikro-Pulsaire Dry Dust Collector

MIKRO- PULSAIRE
DRY DUST COLLECTOR

GENERAL DESCRIPTION

The Mikro-Pulsaire unit is a continuous self-cleaning dust filter capable of removing dust particles as small as sub-micron size from gaseous streams. High dust collecting efficiency is maintained under continuous operating conditions without the use of internal moving parts or rapping mechanisms. Versatile application and simplicity of operation are inherent design features.

The collector (Figure 6) is divided into two dust tight compartments by the tube sheet, (D). The lower compartment is called the housing, (M). The housing contains the filter bags, (A). The filter bags fit around and are supported by wire retainers, (B). The filter bags and wire retainers, as units, are clamped to special "venturi" shaped nozzles, (E), which are fastened to the tube sheet and which extend into the bag/retainer assemblies.

The filter bags are fabricated from material suitable for the temperature, moisture and resistance characteristics of the gas stream (Table 1). Special coating treatments are available to increase collection efficiency. Untreated bags are preferred when the treatment is harmful to the product.

The upper compartment is called the Plenum, (Q). The plenum houses the blowtubes, (F), supports the solenoid valves, (J), diaphragm valves, (K), and compressed air manifold, (L), and provides an exhaust outlet, (R), for the filtered gas. The blowtubes, with orifice nozzles, (G), are located above each row of filter bags such that the orifice nozzles are directly above the throat of each venturi in that row.

The collector housing is designed to accept a hopper, (O). The hopper usually provides an inlet for the dust-laden gases and an outlet for the collected dust. The hopper outlet is adaptable to airlock, slide gate or screw conveyor control.

A diffuser (T) (if supplied) absorbs the impact of high velocity dust particles and distributes the flow of the incoming air.

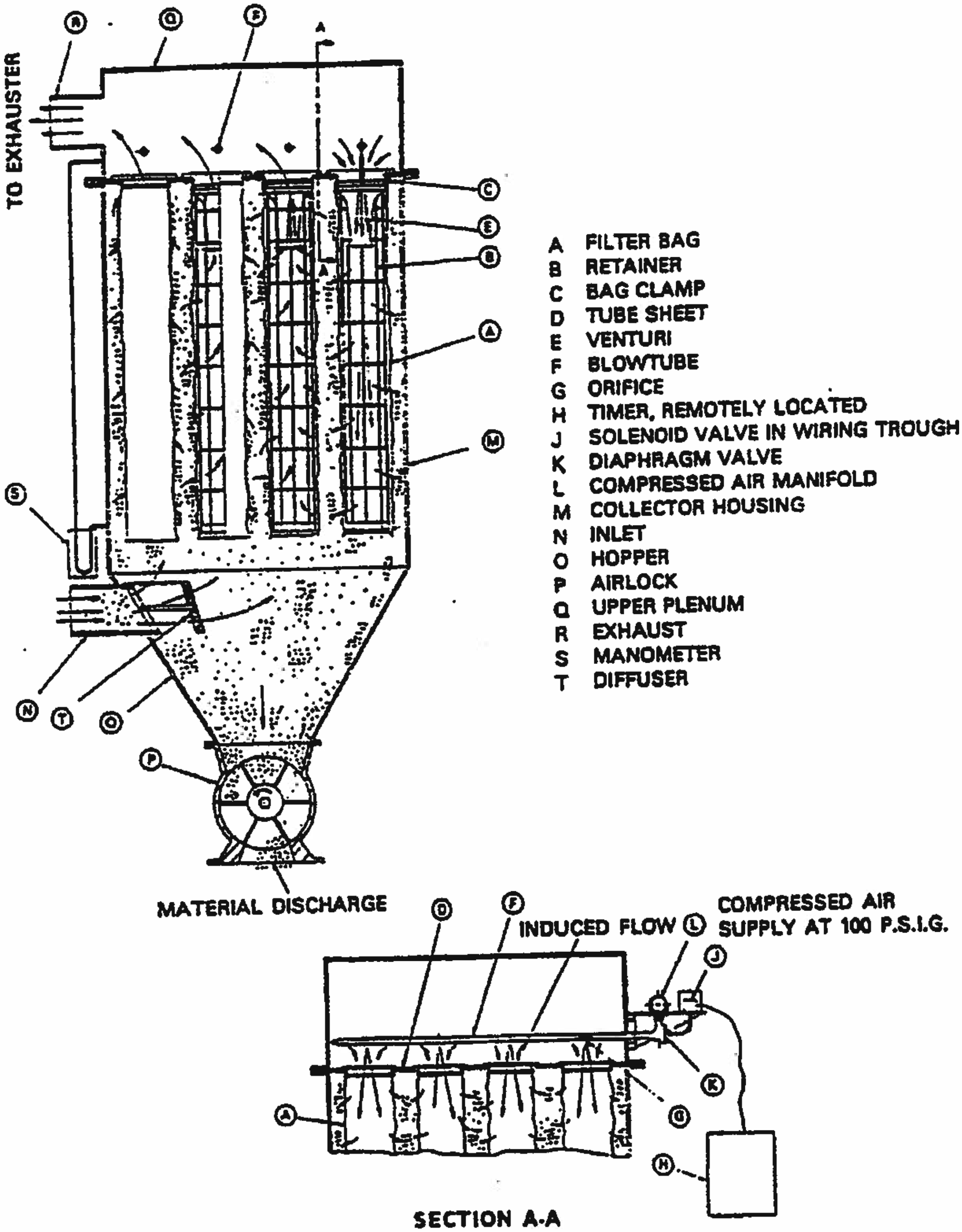
Each collector has a manometer (S), or magnehelic gauge supplied with it. The field installed manometer or magnehelic gauge registers the pressure differential across the collector making it a useful tool for monitoring the efficiency of the pulse jet cleaning of the bags.

THEORY OF OPERATION

Dust laden air under suction or pressure enters the lower section of the collector (Figure 6). The air travels through the filter bags, which retain the dust particles, on up through the venturis, into the clean air plenum and out the collector exhaust.

Dust collection on the outside of the filter bags causes a reduction in the porosity of the bags. The result is a pressure differential between the dirty and clean air sides of the collector. To control the pressure differential across the collector, a cyclic timer actuates a series of normally closed solenoid valves at present intervals causing them to open. The diaphragm valve opens as a result of the decrease in pressure from the opening of the solenoid (for detailed operation of the solenoid and diaphragm valves, see Figure 7). A momentary in-rush of high pressure air (90-110 PSIG) flows from the compressed air manifold to the blowtube and is expelled from the blowtube through orifices at a high velocity. Air from each orifice induces a secondary airflow several times the volume of surge air as it passes through the venturi throat. The combined effect of the primary and induced secondary air causes an instantaneous pressure rise on the clean side of the filter bags, causing a

Figure 6. Operational Components



SCHEMATIC OF MIKRO
PULSAIRE COLLECTOR

reverse flow of air through the filter bags sufficient for cleaning. Through this mechanism, the collected dust is released from the bags and falls into the hopper. As dust falls into the hopper, it is discharged into a collection system which may be a bin under the hopper or a conveying system which carries the dust to a remote disposal area.

Since only a fraction of the total filter area of the collector is cleaned at any one instant, continous flow through the collector at rated capacities is assured.

START-UP

1. *Spray Dryer or Process Equipment*

   Initial adjustments must be made on the system before installing bags in the collector. An incorrectly functioning dryer or other process equipment may result in destruction of the bags if temperature or moisture is not in control. When used with drying equipment, preheat the collector for 30 minutes to 1 hour before start-up with material to eliminate the danger of condensation in the collector.

2. *Start-Up with New Filter Bags*

   Close inlet or exhaust dampers approximately 50% before attempting to start up with new filter bags. High speed impingement, due to low resistance to air flow, can cause dust penetration of the filter bags. This will be particularly true when the air stream carries materials which tend to "blind" the bags. Open the inlet damper to design flow only after the filter bags have built up resistance (3 to 4 inches w.g. on the manometer). The timer ~~controlling the~~ compressed air pulsing should not be turned on until the differential pressure has reached 4 to 5 in. w.g., unless unattainable or if operating conditions will not permit this pressure drop.

3. *Normal Start-Up (with seasoned bags)*

   Apply power to all auxiliary equipment (except fan). Energize timer and turn on compressed air. Introduce gases to the collector by opening dampers and starting fans.

CAUTION: Low collector resistance may overload the fan.

4. *Differential Pressure Control*

   The expected differential pressure operating range is 1 to 6 inches w.g. If this tolerance cannot be maintained, adjust the cleaning cycle on the timer.

   a. To reduce differential pressure, adjust time delay so that cleaning pulses occur at a more frequent rate (shorter OFF time).

   b. To increase differential pressure that is on the low side, adjust time delay so that cleaning pulses occur at a less frequent rate (longer OFF time).

Shutdown

De-energize the fan and close inlet and exhaust dampers. Wait a period of 15 to 30 minutes, turn off compressed air and timer. Turn off all auxiliary equipment. The hopper(s) should be emptied of material before the airlock and/or screw conveyor is turned off.

If there is no inlet damper, the fan should be left on at a reduced flow when pulsing the bags down to avoid dusting in the ductwork up-stream of the collector.

SAFETY

IMPORTANT: Prior to operating this equipment, read this list of safety recommendations through in its entirety, along with the Operating Instructions.

A. During baghouse erection, objects lifted by crane or hoist must be securely fastened and carefully handled to prevent injury to personnel. If lifting lugs are available, they should be used according to sound engineering practice. When overhead work is being performed, all areas below the collector must be restricted for unauthorized personnel. Personnel in the area must wear safety gear complying with plant safety standards.

B. Work crews should always consist of two or more persons. *Never allow personnel to work inside the collector alone.* After work has been completed, all tools should be removed from within the baghouse and ALL PERSONNEL MUST BE ACCOUNTED FOR PRIOR TO CLOSING THE UNIT AND STARTING UP.

C. Before entering a Mikro-Pulsaire, switch off the power to the exhaust fan (blower), screw conveyor (where applicable), airlock, timer and other related equipment. A means of locking these switches in the "off" position should be made, and the key to the lock(s) should be with one of the personnel entering the unit. The compressed air should also be off and a suitable respirator and eye protection worn. Purge system of all gases and vapors other than air. Be certain gas flow has ceased and temperatures are at a safe level.

D. When installing or removing filter bags within the baghouse (standard units) the internal catwalk should always be used. On some units, the catwalk consists of a small removable platform that is simply slid along within the unit on support rails. As an additional precaution while inside the unit, a safety cable can be installed across the unit, just underneath the tube sheet, and personnel can wear safety harnesses that are secured to the cable.

E. The compressed air manifold assembly is designed to safely handle up to 125 psig compressed air. Precautions should be taken to see that this maximum pressure is not exceeded.

F. Use caution when wiring the pilot valves or timer to avoid shock. The power should always be off when this is done.

G. Whenever adjusting either the on-time or off-time of the timer, be very careful not to touch any components on the timer that are electrically "hot." The potentiometers are easily adjusted by hand and a screwdriver should not be used.

H. If frequent access to the unit is required, a sturdy external catwalk assembly should be installed, along with handrailings, ladder and safety cage. If the unit is a top-removal style, then handrailing should be installed around the perimeter of the plenum roof area.

I. Whenever servicing or adjusting the pilot valves or diaphragm valves, be certain that the compressed air has been turned off and the system throughly bled to atmospheric pressure.

J. If the material being collected by the Mikro-Pulsaire is explosive (by nature) or can become explosive under conditions that may exist in the unit, explosion venting protection should be installed. Depending on the severity of the condition, fire and explosion suppression equipment may also have to be installed to afford safe operation of the baghouse system.

K. As an additional safety precaution to avoid dust explosions, filter bags with ground straps or conductive bags can be employed. At the same time, all sections of the baghouse and accessory equipment should be effectively grounded.

L. When explosion vents are used on Mikro-Pulsaires located inside a building, the vent areas should be ducted to the outside of the building. This will provide safety for passersby and will not permit any burning dust or bag material to be scattered inside the building.

M. If the cleaned exhaust from the Mikro-Pulsaire is to be recycled back into the building for heat recovery or makeup air, provisions must be made to bypass the return flow outside the building should a filter bag develop a hole or some other problem. A back-up filter should also be used when the exhaust air is recycled to work areas. This will protect personnel in the plant from inhaling the dust in the event of a baghouse problem.

N. The fan discharge from the Mikro-Pulsaire collector should be directed to an area away from pedestrian traffic in the event of a bag failure.

O. When dust or product is present in the baghouse or related equipment connected to the baghouse, no welding or other spark producing operation (e.g., grinding, drilling) should be performed on the equipment until the system is shut down and thoroughly cleaned of the dust or product. If welding is to be performed in the area of the filter bags, the bags should first be removed and stored in a dry, remote location.

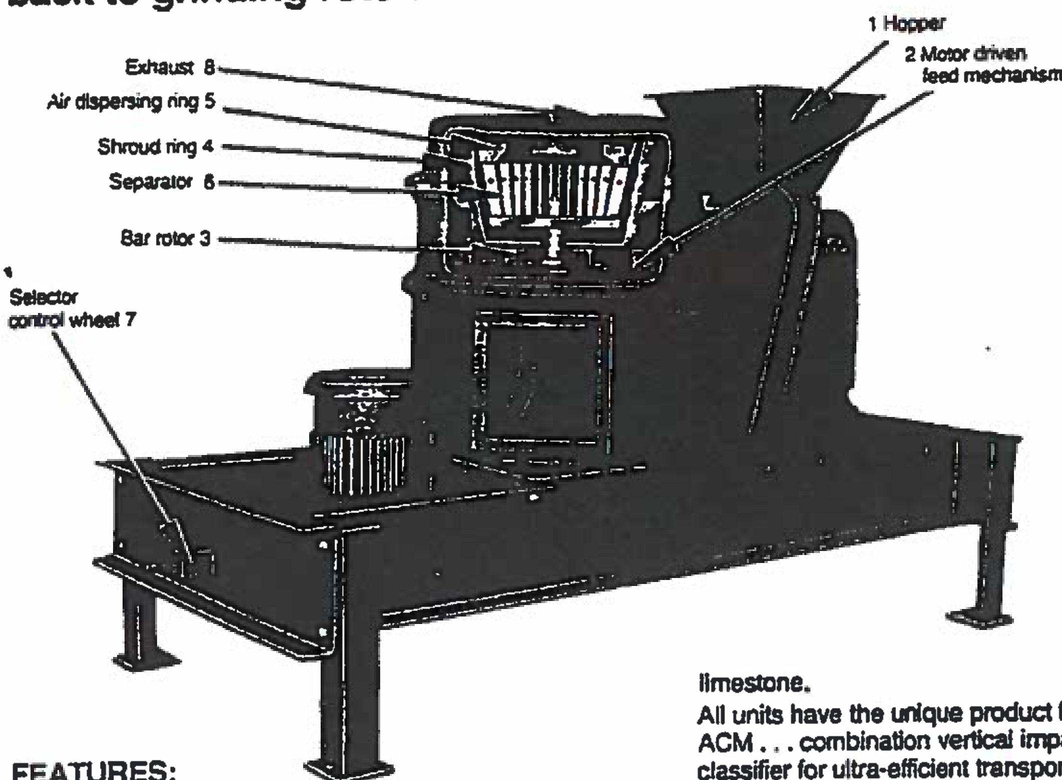
Appendix C – Equipment Specification Sheets

Attachment C-2 – Lime Preparation System

Mikro-ACM™ Pulverizers

Model 200 . . . Model 60 . . . Model 30 . . . Model 10

Designed for more efficient transportation of ground material from grinding rotor to separating element . . . rejecting oversize material back to grinding rotor.



FEATURES:

- Economical, Efficient Recovery of Fine Powders
- Particle Size Readily Adjustable Without Shutdown
- Simple to Clean, Maintain and Operate
- Low Grinding Temperature

THE MIKRO ACM PULVERIZER . . .
is a classifier-pulverizer which utilizes a unique, internal circulation of material for producing fine grinds at high capacities. A primary operating feature is a selector control wheel which permits shifting from one grind to another over a wide range of particle sizing from intermediate to ultra-fine grinds, without shutting down the mill.

THE NEW MIKRO ACM PULVERIZERS . . .

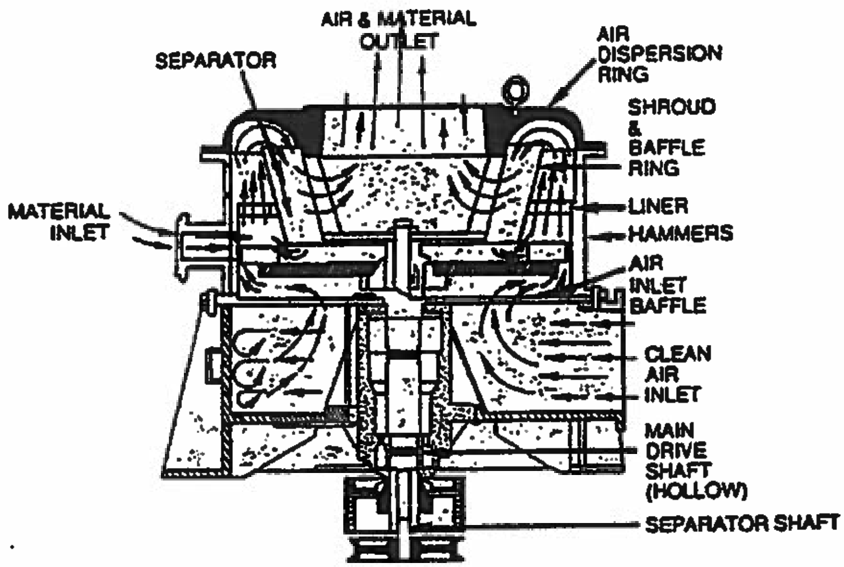
The most efficient fine-grinding particle reduction mills in the industry. Pulverizing Machinery has added two new Mikro ACM Pulverizers to its product line. One is a 30 hp unit, midway between 10 and 60 models. The other is the most powerful mill in Pulverizing Machinery history, a 200 hp unit that can turn out up to 20 tons per hour of 200 mesh limestone.

All units have the unique product features of the ACM . . . combination vertical impact mill and integral classifier for ultra-efficient transportation of ground material from the grinding rotor to the separating element. All units conveniently adjusted for instant shifting from one grind to any other grind from 100 mesh to ultra fine grinds. All have a constant air flow which maintains a reasonably low grinding temperature. The flow-thru exhaust improves the units ability to handle materials that have a tendency to stick or pack.

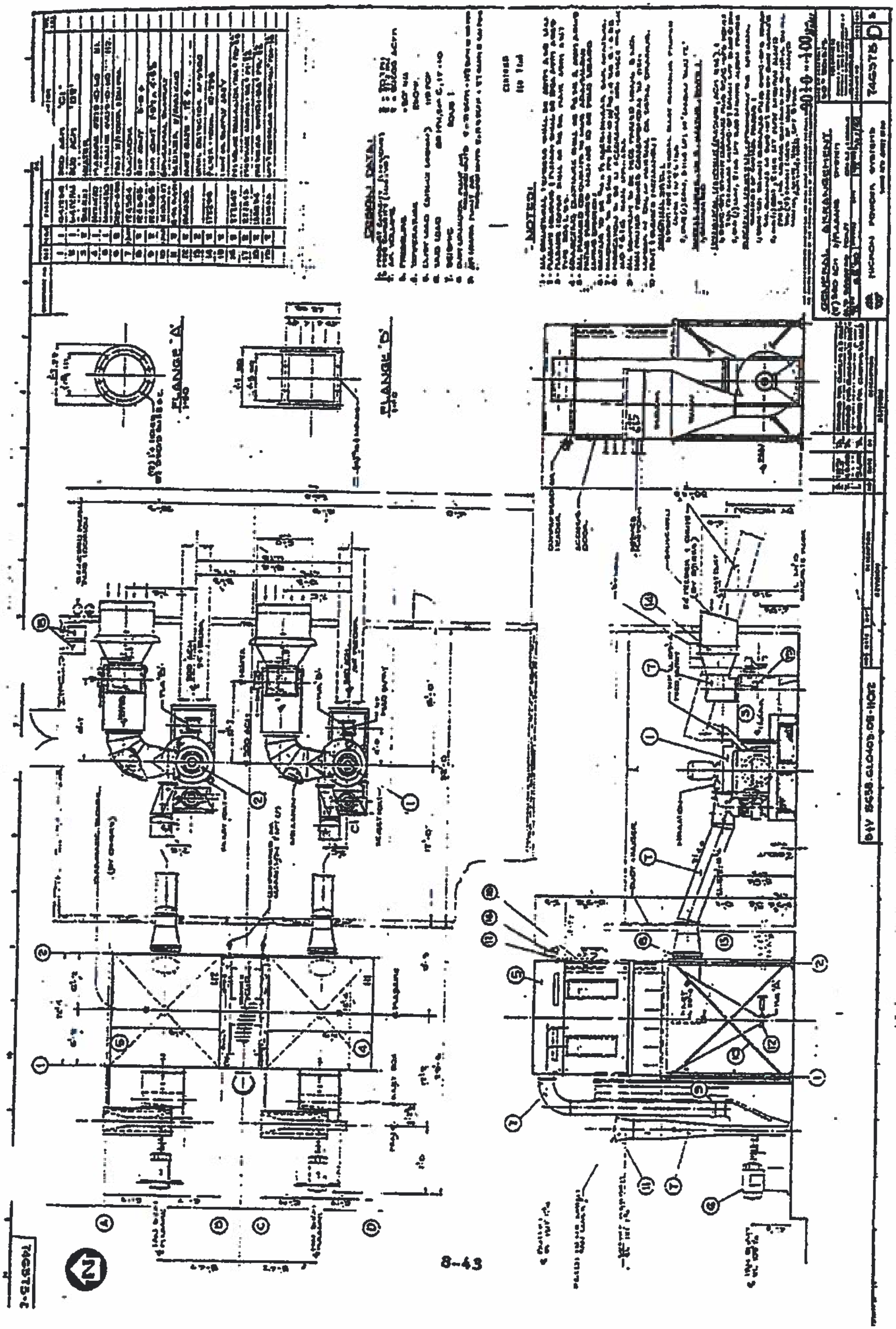
PRINCIPLE OF OPERATION . . .

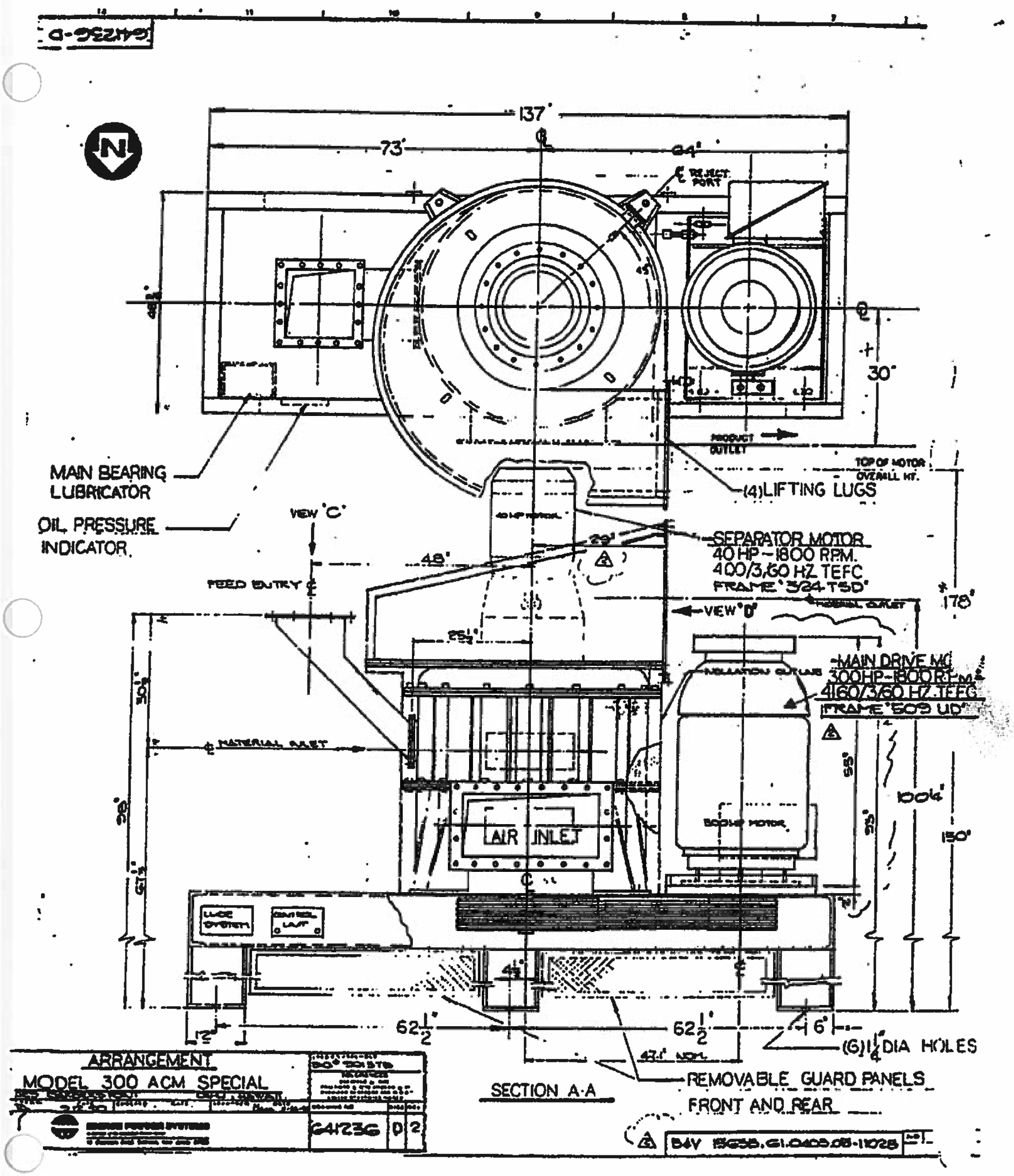
The material to be ground is conveyed from the hopper (1) by means of motor-driven feed mechanism (2) to a pin or bar rotor (3) where breakup of material occurs. As particles decrease in size they are entrained by the air stream which enters below the rotor, and are carried up between the inner wall and shroud ring with baffles. (4) The particles are then deflected inward by an air dispersing ring (5) to be either accepted or rejected by the separator (6) which may be adjusted for specific particle size selection by the speed selector control wheel (7).

Acceptable ground particles are drawn upward through the exhaust (8) and to the collector. Oversize particles are carried downward by the internal circulating airstream and returned to pin or bar rotor for additional grinding.



Sectional of MIKRO ACM PULVERIZER, illustrating air and material flow.





137"
73"
64"
30"
178"
MAIN BEARING LUBRICATOR
OIL PRESSURE INDICATOR
VIEW 'C'
FEED ENTRY
48"
29"
(4)LIFTING LUGS
SEPARATOR MOTOR
40 HP - 1800 RPM.
400/3,60 HZ TEFC
FRAME '324 TSD'
VIEW 'D'
MAIN DRIVE MOTOR
300HP-1800RPM
4160/3/60 HZ TEFC
FRAME '509 UD'
MATERIAL INLET
AIR INLET
100¼"
150"
62½"
62½"
6"
(6)1¼" DIA HOLES
REMOVABLE GUARD PANELS FRONT AND REAR
SECTION A-A
ARRANGEMENT
MODEL 300 ACM SPECIAL
64123G
D
2

Limestone Particle Size

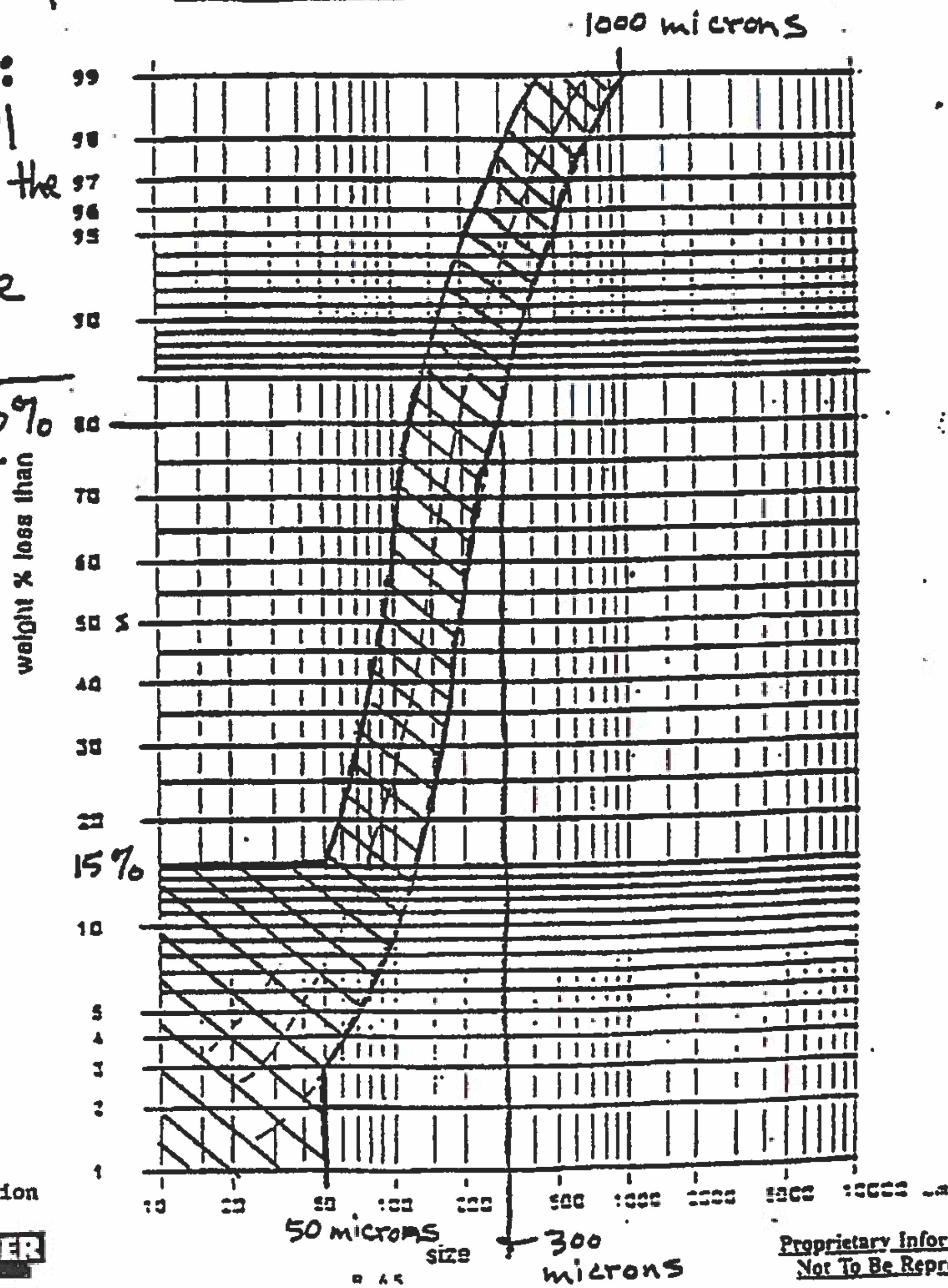
Figure 2M-1

Size distribution required to be within this envelope

Percent Less Than	Size
~~100~~	~~1,000 microns~~
~~95~~	~~350 microns~~
~~90~~	~~250 microns~~
~~70~~	~~175 microns~~
~~50~~	~~150 microns~~
~~20~~	~~90 microns~~

Not req'd to be met

For example:
65 % of mat'l could be in the 50 thru 300 microns size as long as remaining $\boxed{80\%}$ mat'l is within shaded area.



AES/BP 15638
3/20/90

* Negotiated Revision

Appendix C – Equipment Specification Sheets

Attachment C-3 - ABB Filter Fabric Baghouse

3.0 EQUIPMENT DESCRIPTION/INSTALLATION

3.1 DESIGN CONDITIONS

3.1.1 Unit Operating Conditions

The Flakt baghouses are for a circulating fluidized bed (CFB) boiler cogeneration plant.

3.1.2 Induced Draft Fans

Owner furnished induced draft fans will be used by the owner to maintain the baghouse at below atmospheric pressure. Discharge from these fans will be into the Owner's stack.

3.1.3 Flue Gas Condition

1. Inlet dust load to collector system - 10.5 grains/ACF (including flyash re-injection).
2. Flue gas volume - 306,000 ACFM at 269°F per baghouse and -15" W.G.
3. Maximum flue gas temperature at baghouse inlet - 450°F.
4. Normal flue gas operating temperature - 269°F.
5. Raw material analysis - see Figure 1.

3.2 BAGHOUSE DESIGN DESCRIPTION

3.2.1 Basic Design:

Number of baghouses	2
Number of compartments/baghouse	8
Number of bags per compartment	264
Total number of bags/baghouse	2,112
Bag diameter, inches	12"
Bag length, ft-in.	34'-6" O.A.
Bag area, sq. ft.	103.7
Total area sq. ft./compartment	27,369
Total area sq. ft. for baghouse	218,952
Reverse air volume, ACFM	54,742

FIGURE 1

BARBERS POINT FUELS

COAL DATA PROXIMATE ANALYSIS

	PERFORMANCE	RANGE/MAXIMUMS	ANTICIPATED
MOISTURE, %		9.0 - 17.00	10.0 (ADB)
ASH, %		4.0 - 10.0	7.0 (ADB)
VOLATILE, %			37.5 (ADB)
FIXED CARBON, %			45.5 (ADB)
HEATING VALUE, BTU/LB	10,800	10,000 - 12,400	
SULFUR, %		0.3 - 1.0	0.4 (ADB)
MOISTURE, %	13.5		13.5 (As Rc)
CARBON, %	61.5	76 MIN	77.5 (DAF)
HYDROGN, %	4.4	6 MAX	5.5 (DAF)
NITROGEN, %	1.4	2 MAX	1.7 (DAF)
CHLORINE, %		0.01 MAX AS Rc	
SULFUR, %	0.4	1 MAX	0.4 (DAF)
ASH, %	7.0		
OXYGEN, %	11.8	15 MAX	14.9 (DAF)

MINERAL ANALYSIS OF ASH, %

	PERFORMANCE	RANGE/MAXIMUMS	ANTICIPATED
PHOSPHATE PENTOXIDE (P_2O_5		1 MAX	0.5
SILICA (SiO_2)		55 MAX	37.0
FERRIC OXIDE (Fe_2o_3)		20 MAX	16.8
ALUMINA (Al_2O_3)		35 MAX	20.0
TITANIA (TiO_2)		1 MAX	0.6
LIME (CaO)		12 MAX	8.8
MAGNESIA (MgO)		8 MAX	5.8
SULFUR TRIOXIDE (SO_3)		1 MAX	1.0

POTASSIUM OXIDE (K_2O)		2 MAX	0.9
SODIUM OXIDE (Na_2O)		3.5 MAX	2.8
(MN_3O_4)			0.1
SODIUM AND POTASSIUM (K_2O+Na_2O) (COMBINED)		5 MAX	
VOLATILITY		39 MAX (AS Rc)	
DELIVERY SIZE		100 MM (4") MAX 20% MAX LESS THAN 28 MESH	98% LESS THAN 50 MM (2") 15% MAX LESS THAN 28 MESH
HARD GROVE GRINDABILITY INDEX		80 MAX	45
NOTE: ADB - AIR DRY BASIS DAF - DRY ASH FREE BASIS			

BARBERS POINT LIMESTONE

	PERFORMANCE	RANGE/MAXIMUMS	ANTICIPATED
$CaCO_3$		80% MIN	
$MgCO_3$		10% MAX	
OTHER INERTS (INCLUDING NaCl)		1% MAX	
MOISTURE		6% MAX	
DELIVERED SIZE		3/4 X 0 TO 1.2" MAX - NOT MORE THAN 25% PASSING 28 MESH	

BARBERS POINT SUPPLEMENTAL FUEL

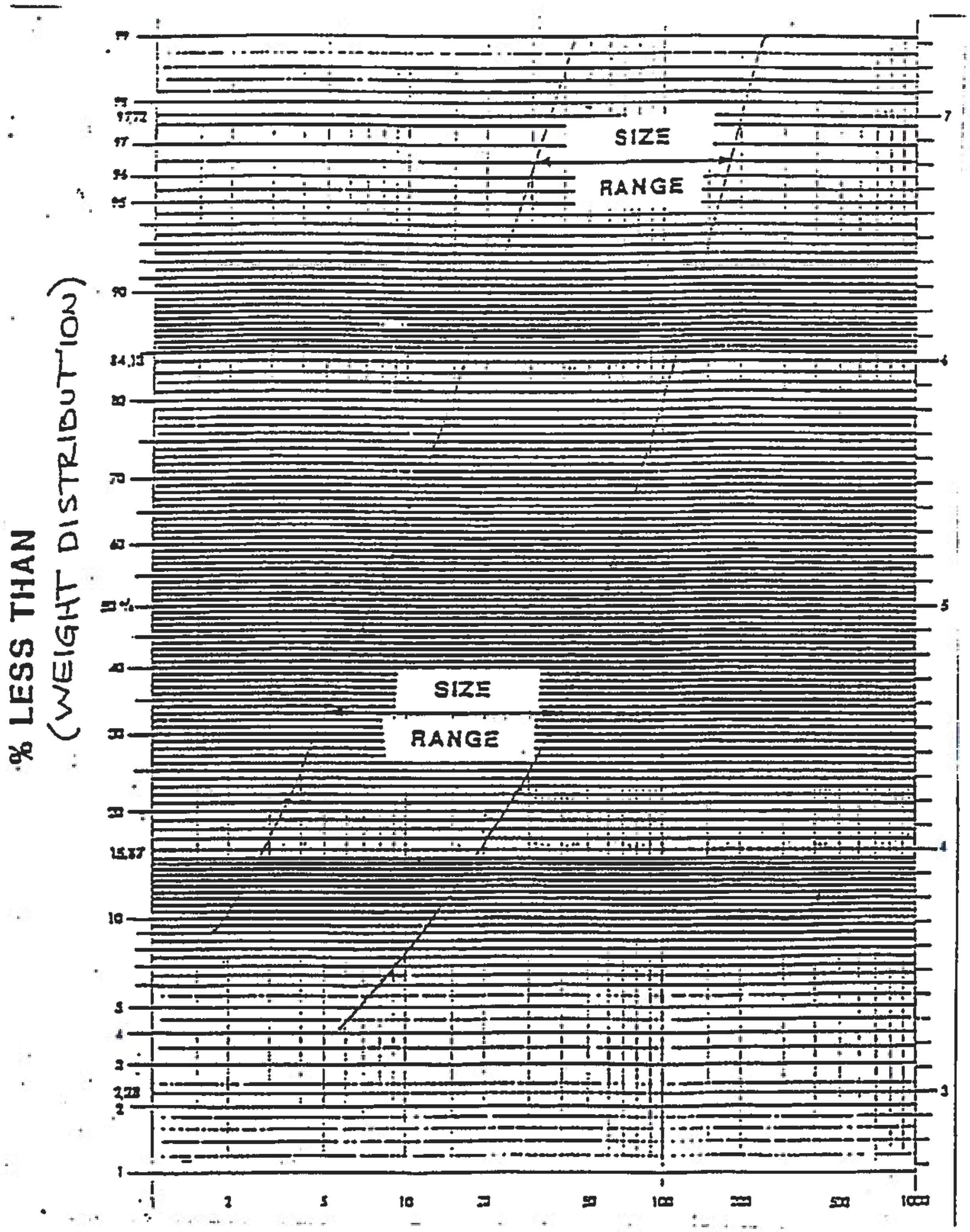
NO. 2 COMMERCIAL GRADE FUEL OIL IN ACCORDANCE WITH ASTM D396 OR SIMILAR FUEL.

FLYASH RE-INJECTION

THE FLYASH RE-INJECTION SYSTEMS WILL BE PLACED IN SERVICE OR REMOVED FROM SERVICE AT THE OWNER'S DISCRETION AND BASED ON THE AVAILABILITY OF FLYASH FOR RE-INJECTION. THE UNITS MAY BE OPERATED FOR EXTENDED PERIODS OF TIME WITH OR WITHOUT FLYASH RE-INJECTION. AN ASH PARTICLE SIZE DISTRIBUTION CURVE IS ATTACHED. THIS CURVE IS REPRESENTATIVE OF OPERATION WITHOUT ASH RE-INJECTION. SMALLER PARTICLES MAY RESULT WHEN RE-INJECTION IS EMPLOYED.

ASEA BROWN BOVERI Environmental Systems Division	AES - BARBERS POINT EMISSION CONTROL SYSTEM OPERATIONS AND MAINTENANCE MANUAL EQUIPMENT DESCRIPTION/INSTALLATION	PROJECT NO. 325 APRIL 19, 1991 SECTION 3 PAGE: 3 - 5 REV: 0

FLYASH PARTICLE SIZE RANGE (BAGHOUSE INLET)



3.2.2 Air-to-Cloth Ratios

Gross air-to-cloth ratio	1.4:1
Net air-to-cloth ratio, one compartment out for cleaning and one compartment out for maintenance.	2.2:1

3.2.3 Filter Fabric Bag Construction

Material	Woven fiberglass w/teflon finish.
Diameter	12 inches
Bag length	34.5 feet
Weight (oz/sq.yd.)	10.3 oz.
Weave	3 X 1 twill
Permeability, CFM/sq. ft.	1/2" W.G., 35-60 CFM sq. ft.

Top suspension method ----- "J" Hook, compression spring and cap. Compression band sewn into top of bag for retainment over cap.

Bottom Attachment --------- Filter bag slip over thimble and is secured with stainless steel clamp.

Filter Tube Rings --------- 3/16" dia. cadmium plated steel are sewn into bag so that the bag does not collapse upon itself during reverse air cleaning, eight (8) rings per bag.

Installation, Tension and Adjustment ------------ Tension is shown by deflection of spring. 75# tension is initial setting. (See Drawing No. 325-11-00-E-01, Section 10).

3.3 INSTALLATION

3.3.1 Preliminary Inspection

3.3.1.1 Before installing or storing this equipment, inspect all items for shipping damage. Check the delivery list to determine that all parts are accounted for.

CAUTION: OBSERVE ALL APPLICABLE NATIONAL AND LOCAL CODES WHEN PERFORMING ELECTRICAL INSTALLATION.

3.3.1.2 Installation of Fabric Filter System must conform to the arrangement drawings (Section 10) and the instructions supplied with system components in Section 11.

3.3.2 Storage Requirements

3.3.2.1 In the event this Fabric Filter System or its components are not installed immediately, attention must be directed to proper methods of storage. The table below lists shelf life requirements under specific conditions for Flakt supplied equipment.

EQUIPMENT	0 - 6 MONTHS	7 - 18 MONTHS	19 - 36 MONTHS
ELECTRICAL COMPONENTS, CONTROL EQUIPMENT	3	4	4
GATES, MECHANICAL ASSEMBLY, MACHINE CASTINGS	2	3	4
CLOSED CRATES AND BOXES	2	3	
STRUCTURAL STEEL	1	1	3
BAGS (IN-CARTONS)	5	5	

CODE:
1 - UNPROTECTED OUTDOOR STORAGE
2 - PROTECTED OUTDOOR STORAGE (ELEVATED AND COVERED)
3 - UNHEATED INDOOR STORAGE
4 - HEATED INDOOR STORAGE
5 - HEATED INDOOR STORAGE FOR NOT MORE THAN 12 MONTHS

3.3.1.1.1 Always store components and equipment in an upright position.

NOTE: INDOOR STORAGE IS PREFERABLE

3.3.1.1.2 Remove all fan belts and store in a heated enclosed area.

3.3.1.1.3 Rotate fans and motors once a month.

3.3.1.1.4 Filter bags are shipped in cartons. DO NOT remove filter bags from their protective carton until ready to install.

CAUTION: DO NOT STACK PALLETS OF BAG CARTONS.

3.3.3 Filter Bags

CAUTION: SHARP CREASES IN A BAG ARE POTENTIAL LEAKS. DO NOT STEP ON BAGS OR DRAPE THEM OVER STEEL MEMBERS OR PLANKS. DO NOT REMOVE BAGS FROM THEIR PROTECTIVE CARTONS UNTIL READY TO HANG.

3.3.3.1 Transport bags in protective cartons to bag tube sheet elevation of compartment.

3.3.3.2 Installation should proceed from the far corners os each compartment. Maintenance crews must avoid standing on bags during installing.

3.3.3.3 Apply a great deal of caution in handling of bags to ensure long life.

3.3.3.4 Remove bag carefully from cartons.

3.3.3.5 When removing bag, visually inspect for holes, heavy creases, abrasion damages, etc. Do not install the bag in less than perfect condition!

3.3.3.6 Attach hoisting line from bag cap and raise per Step 2, Drawing 325-11-00-E-01.

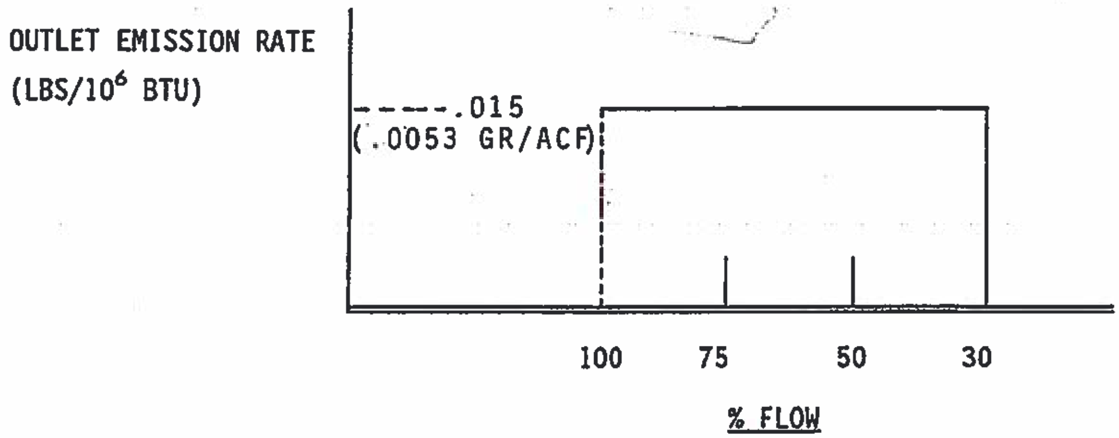
3.3.3.7 After raising bag, attach to bag support steel per Step 3, Drawing 325-11-00-E-01.

CAUTION: THE BAG SEAM MUST ALWAYS BE FACING THE CENTER AISLE OF THE COMPARTMENT (SEE DRAWING 325-11-00-E-01 FOR CORRECT ORIENTATION). DO NOT POSITION CLAMP SCREW HOLDER DIRECTLY OVER BAG SEAM. PERMANENT BAG DAMAGE MAY RESULT IF THE CLAMP SCREW HOLDER IS INSTALLED ON THE BAG SEAM.

3.3.3.8 Adjust bag to remove any noticeable slack.

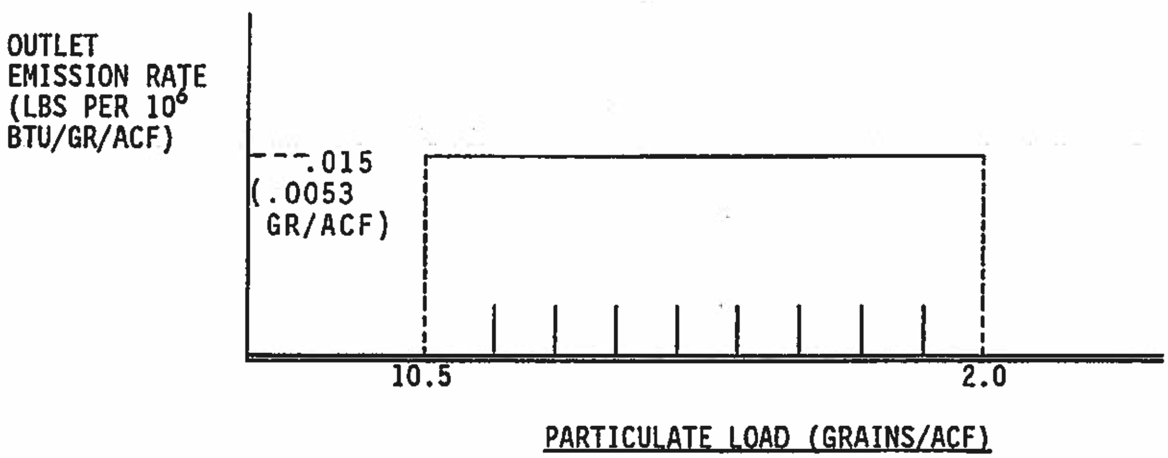
3.4 PERFORMANCE CURVES

<u>OUTLET EMISSION RATE VS. FLUE GAS FLOW RATE</u>

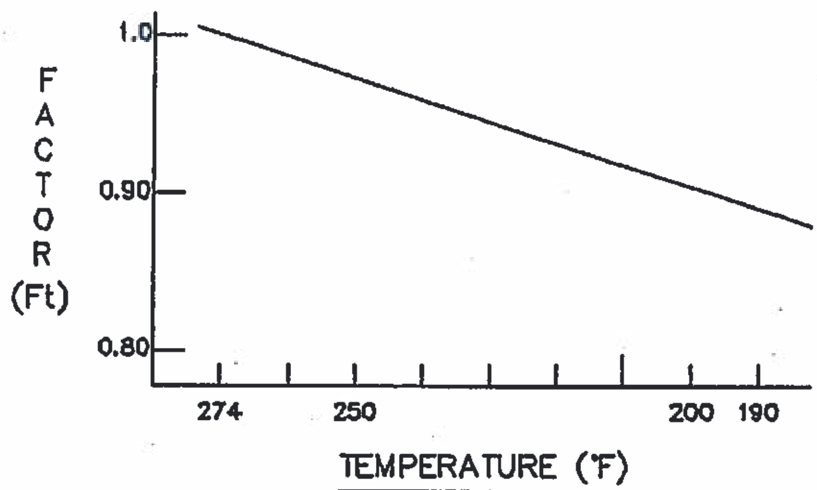


PERFORMANCE CURVE

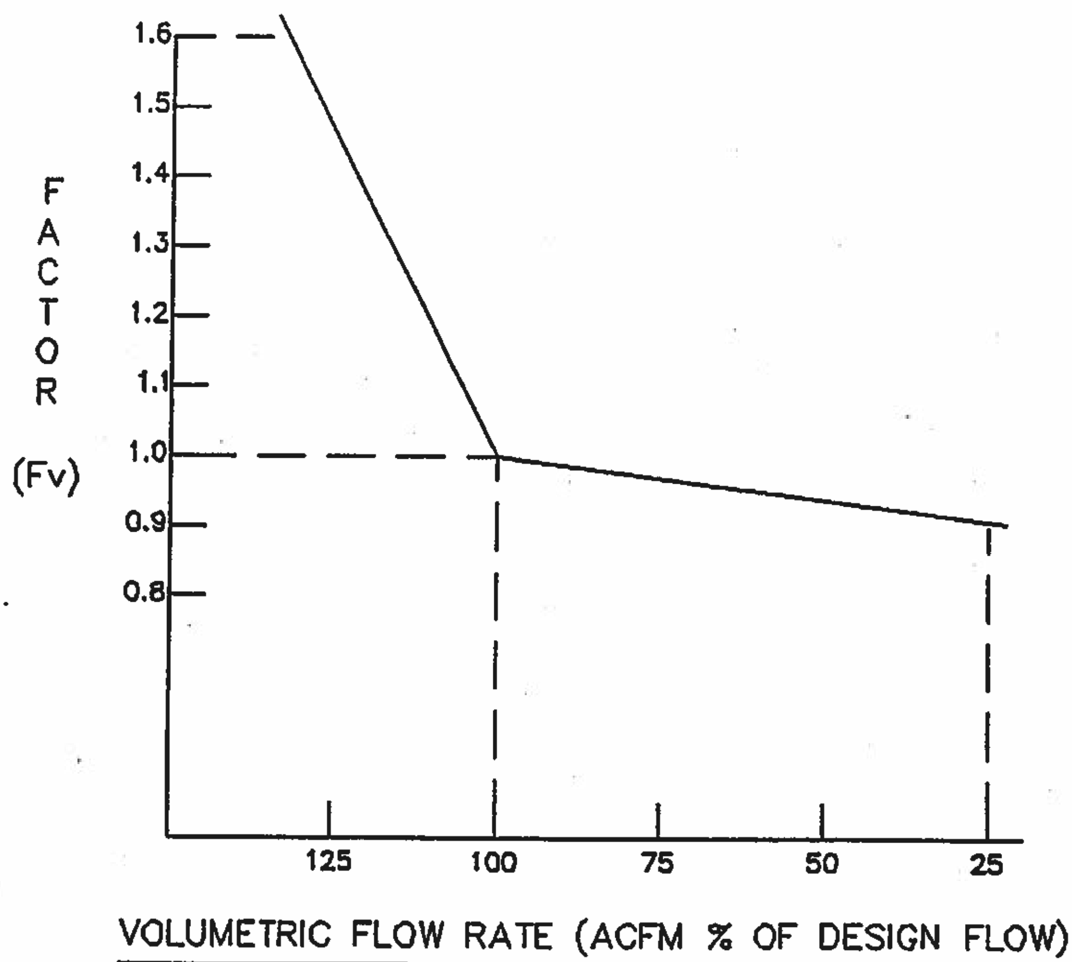
OUTLET EMISSION RATE VS. INLET PARTICULATE LOAD



BAGHOUSE PERFORMANCE FACTOR
CURVE FOR GAS TEMPERATURE (Ft)
(FOR USE WITH FORMULA TO DETERMINE BAGHOUSE PRESSURE LOSS)



PERFORMANCE CURVE FOR TOTAL AVERAGE PRESSURE DROP FOR ABB ES SCOPE OF WORK FOR BARBERS POINT



Appendix C – Equipment Specification Sheets

Attachment C-4 – Cooling Tower

I.1. COOLING TOWER SPECIFICATIONS AND EQUIPMENT DATA SHEET

IF ANY DIFFICULTIES OR PROBLEMS OCCUR, CALL:
GEA INTEGRATED COOLING TECHNOLOGIES, INC.
1-303-987-0123

Tower Model No.	545438-5I-32-FCF
Customer Name	AES HAWAII
Customer Order Number	1610-BOP-9902
GEA-ICT Job Number	99-011
Location	Kapolei, HI
Completion Date	2000

PERFORMANCE DATA

Water Circulation	104,000 US gpm
Inlet Water Temperature	107.8°F
Outlet Water Temperature	89.70°F
Design Wet Bulb Temperature	78.00°F
Evaporation Rate	1555gpm
Pump Head	28ft
Fan Break Power	197Hp
Elevation	0

TOWER DESIGN DATA

Type	Fiber Glass Counter Flow Cooling Tower
No. of Cells	5
Cell Size	54ft x 54ft
Overall Length/Width	270ft x 54ft
Basin Curb to Distribution Center Line	23ft
Air Inlet Height	12ft
Fan Deck Height	37.6ft
Fan Stack Height	10ft
Distribution Type	Upspray
Drift Eliminator Type	Cellular
Access to Top of Tower	2 Stair Towers
Fill Type	GEA V
Fill Height	5ft
Fan Deck Live Load	60lb/ft^2
Snow Load	0
Design Wind Velocity	130mph

MATERIALS

Tower Structure	Fiberglass
Bolting Hardware	SIL BRZ
Nailing Hardware	316ss
Base Anchors	SIL BRZ
Joint Connectors	SIL BRZ & FRP
Gear Support Members	Epoxy Coated HDG Steel
Fan Stack/Type	FRP
Distribution Headers	FRP-Class 3
Distribution Lateral Lines	PVC SDR 35
Distribution Spray Nozzles	PP
Drift Eliminators	PVC
Fill	PVC
Casing	12oz. Fire Ret. 4.2
Fan Deck	FRP Board w/Grit

FAN DATA

Manufacturer	Hudson
Model	APT-32H-8
Diameter	32ft
Blades/Fan	8
Blade Material	FRP
Hub Material	Epoxy Coated Steel
Fan Speed	119rpm
Tip Speed	11,962ft/min
Outlet ACFM/Fan at Design Conditions	1,415,763 ft^3/min
Total Static Pressure Drop	0.4557 in.of H_2O
Design Fan Pitch	12.5°

GEAR/DRIVE SHAFT DATA

Gear Manufacturer	Amarillo
Model	1712
Rated Capacity	200Hp
Reduction Ratio	15:1
Lubrication Type	Splash
Drive Shaft Manufacturer	Addax
Material	Composite
Service Factor	2.0 minimum
Vibration Switch	Robert Shaw

MOTOR DATA

Enclosure	TEFC
Frame Size	447T
Manufacturer	Siemens
Rated Capacity,	200Hp
Operating Speed	1800rpm
Phase/Cycle/Volts	3/60/460

I.2. A SHORT DESCRIPTION OF A COUNTERFLOW COOLING TOWER

A Cooling Tower consists of the following:

A. A fiberglass framework with fiber-reinforced, plastic, corrugated siding.
B. A system of water distribution pipes and nozzles within the framework.
C. A heat exchange medium (the fill) made up of modular PVC material.
D. A basin to collect the cooled water and direct it back to the circulating pumps.
E. Fans to move the air necessary for proper heat exchange.
F. Drift Eliminator medium to prevent water droplets from escaping from the tower in the air flow.

Operation of the tower centers around exposing warm water to moving air, to affect an evaporative, or latent, heat transfer. This heat is dissipated into the atmosphere. Keep the tower clean and the water distribution uniform to obtain continued maximum cooling capacity. Do not allow excessive deposits of scale or algae to build up on the fill media or the drift eliminators. Keep all nozzle orifices free of debris to assure correct distribution and cooling of water.

The water to be cooled is transported to the distribution level by riser pipes external to the tower. It flows from the risers into a horizontal distribution header pipe. From there it branches into a system of lateral distribution pipes, where nozzles spray the water downward in a predetermined pattern over the heat exchange medium, or fill.

Before the air flow is permitted to exit through the top of the tower, it must pass through the drift eliminators. These are simply a block of material shaped to cause the air to change directions and thus provides impact surfaces which prevent water droplets from being carried out of the tower with the air flow.

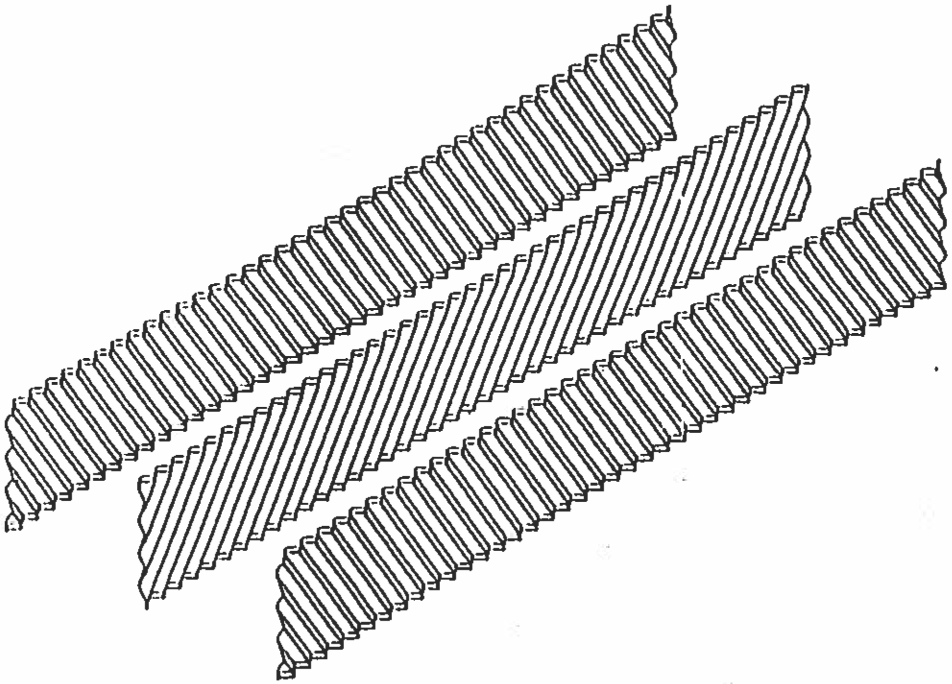
The falling water is caught by the cold water basin, which then directs the flow back to the circulation pumps. The normal water depth in the tower is about 6-12" below top of curb. Adjust make-up water supply to maintain this water level.

The capacity of a tower to cool water is a given cold water temperature varies with the wet-bulb temperature and the heat load on the tower. As the wet-bulb temperature drops, the cold water temperature also drops. However, the cold water temperature does not drop as much as the wet-bulb temperature. A tower does not control heat load. The quantity of water circulated determines the cooling range for a given heat load. The hot and cold water temperature increases with higher heat loads.

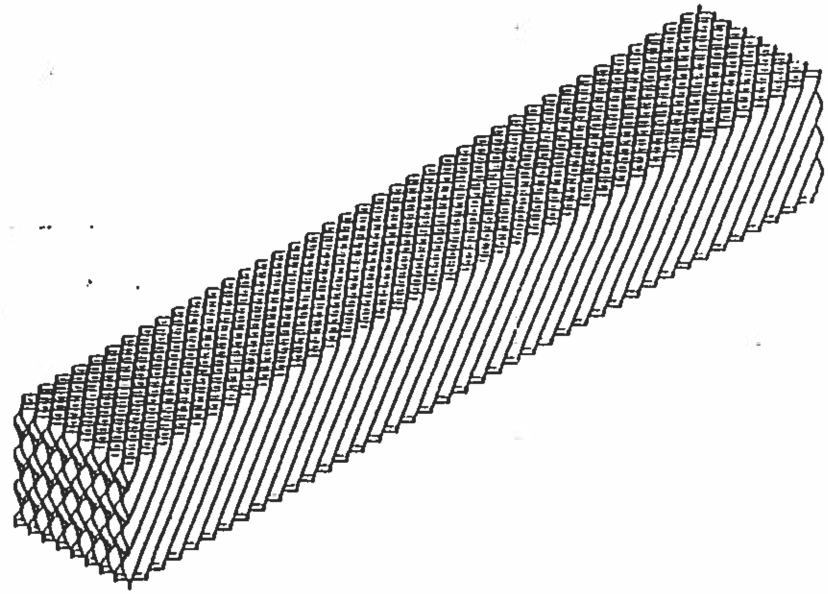
Wet-bulb temperature: the temperature indicated by the wet-bulb thermometer of a sling or mechanically aspirated psychrometer. Also, an indicator of the capacity of the ambient air to receive an amount of water vapor and heat.

Cooling range: the temperature difference between the hot water coming into the cooling tower and the cold water leaving the tower.

Refer to the Performance Curves in this manual for cold water temperature at varying flow rates and varying range.



ISOMETRIC VIEW OF UNASSEMBLED SHEETS
(NOTE: CORRUGATION SLOPE DIRECTION ALTERNATES EVERY SHEET)



ISOMETRIC VIEW OF ASSEMBLED FILL PACK
(NOTE: 12" FILL BLOCK CONSISTS OF 16 SHEETS)

GEA Thermal–Dynamic Towers, Inc.

Thermal Technology Division

SCALE: NONE		DWG TITLE: GEA–5 ISOMETRIC STANDARD DRAWING	
DRAWN BY: CLK	DATE: 1-21-11		
CHECKED BY:	DATE:		
ENGINEERING:	DATE:	DATE: ALL DRAWING CHANGES MUST BE DONE BY COMPUTER	DRAWING NUMBER: GEA–5
PROJECT:	DATE:		SHEET: 1 OF 1
			REV: A

Instructions for On-Site Hand Assembly of GEA Drift Eliminator Modules

P: PROJECT\CONSTRUCTION\ERECTION PROCEDURES\GEADEASSM.2-17-99

The GEA cellular drift eliminator module consists of two (2) types of parts:

- The "big wave"
- The "small wave"

The following pages include sketches for identifying the different parts and their characteristics.

Assembly Instructions

Step 1. Set up the glue box. Position with approximately twelve (12") inches (305 mm) of clear space in front of you (between you and the glue fixture).

Step 2. In the space in front of you, place a pile of "big wave" sheets in the upright position.

Step 3. In another convenient place, set a stack of "small wave" sheets in the upright position.

Step 4. Start by setting an unglued "big wave" in the bottom of the glue box in the upright position.

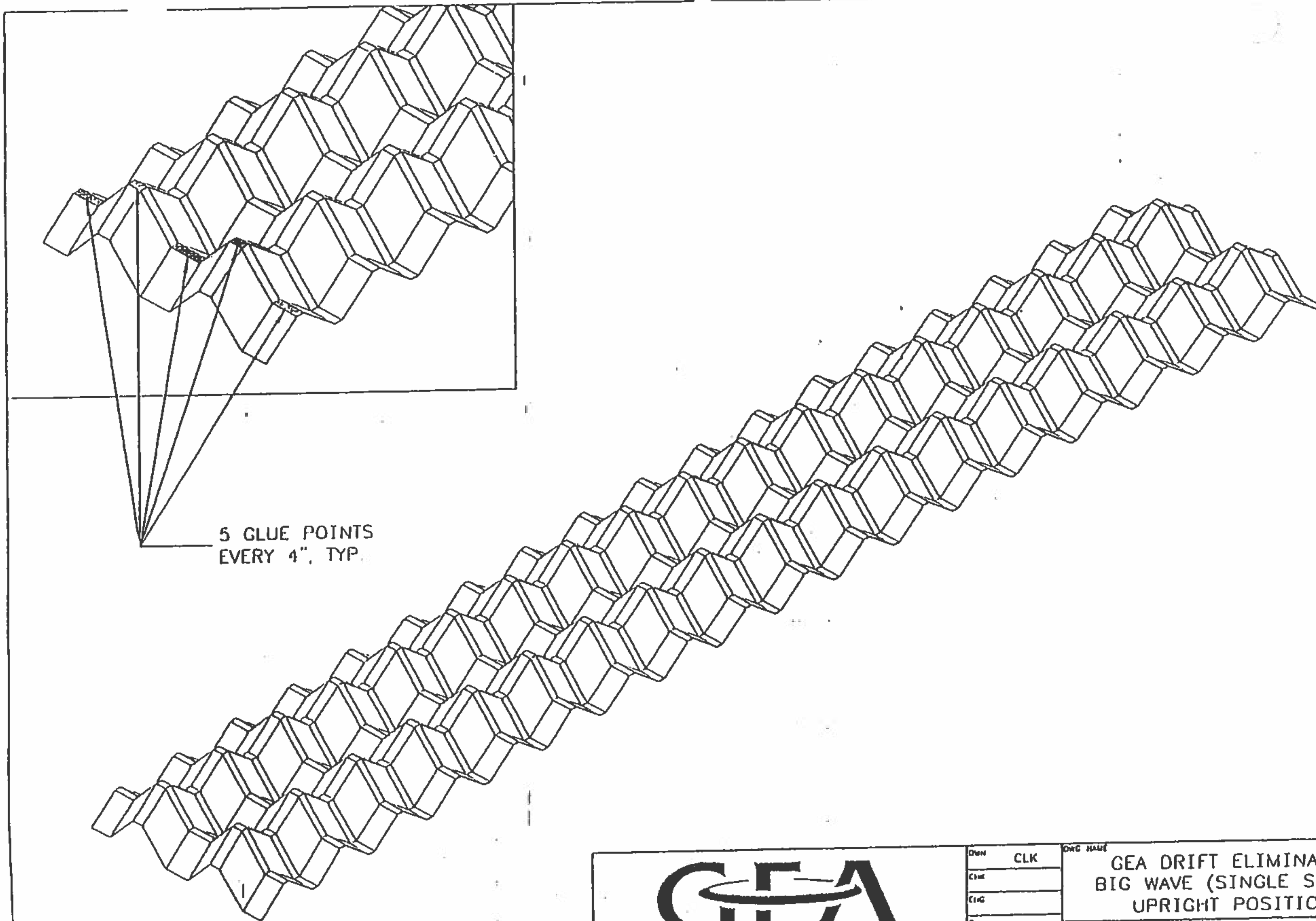
Step 5. Using glue bottle, apply a small amount of glue to each of the 5 glue points (enough glue to cover glue point, but not so much as to melt the wave) on top of the "big wave" in the glue box.

Step 6. Immediately after applying glue to the "big wave" sheet, stack one "small wave" sheet in the box on top e glued "big wave sheet", being careful to stack all wave sheets in the same fashion. With the "small wave" sheet in place in the glue box, apply glue on the bottom of the "big wave" sheet on the table in front of you. After glue is applied, flip the "big wave" sheet over and stack in the glue box. Apply glue to the top glue points on the newly glued "big wave" in the glue box. Stack another "small wave" sheet on top. Continue the gluing and stacking process until the desired number of sheets are stacked in the glue box.

Step 7. Between stacking each pair of newly glued sheets, take a moment to check each glue point in front and behind the module. Make sure each glue point is in line with the adjoining glue points and touching adjoining glue points. If the glue points do not line up properly, slide "out-of-line" sheets back and forth until they are properly aligned. If a glue point does not touch, take a clothespin, and clamp to close the glue point. Keep in mind to work with enough speed to complete each module in the least amount of time, before the glue sets up.

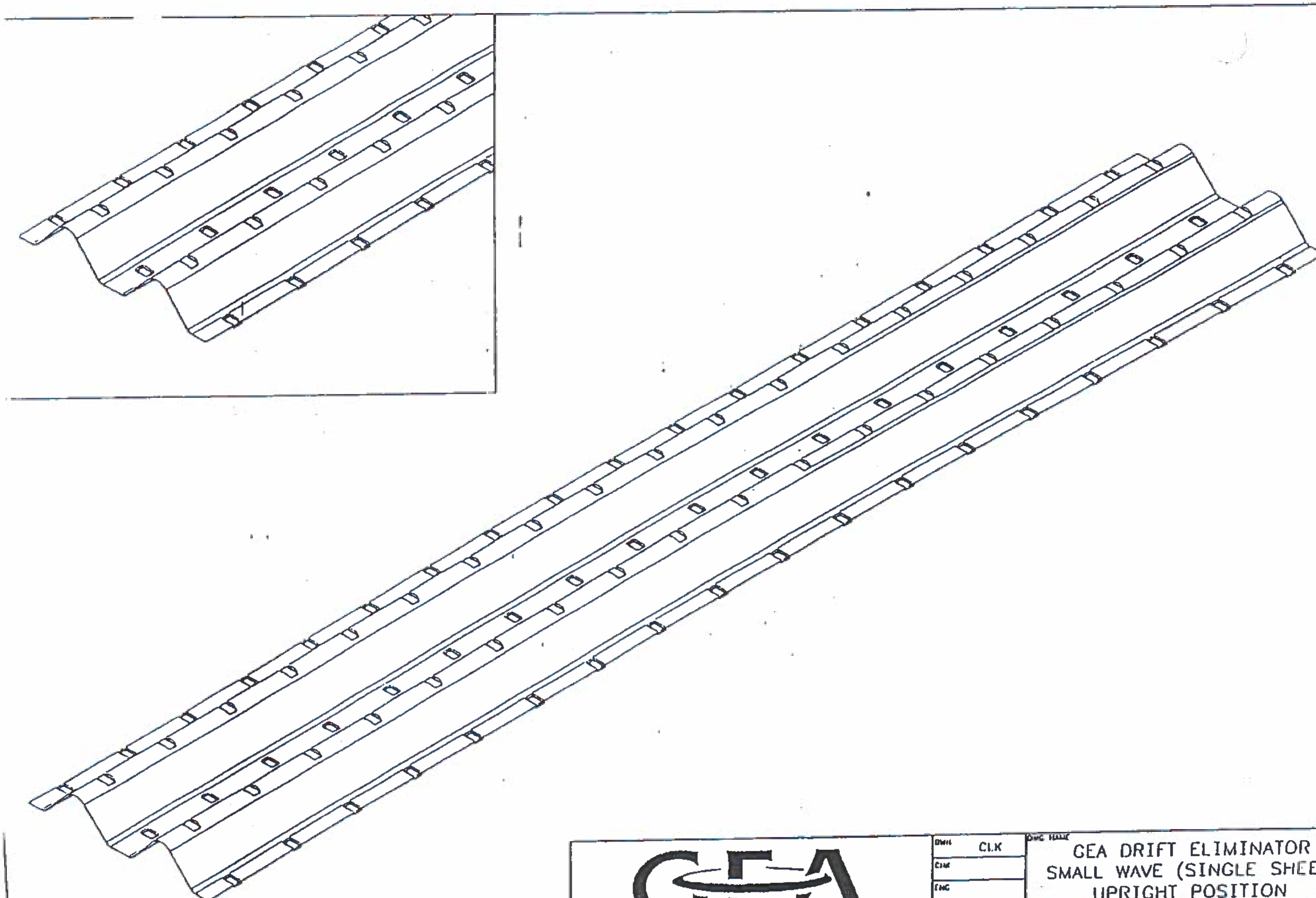
Step 8. When the desired number of sheets are stacked in the glue box, place the top insert board on top of the stack. The board should be placed with the rails down so that they follow the contours of the top sheet. This board provides the needed downward pressure, which slightly compresses the module during the glue curing process. The completed module, with the top insert board in place on top, should be allowed to set in the glue box for at least fifteen (15) minutes before removing from the box. A good practice in production is to build another module in a separate glue box while a completed module is drying or curing. This helps eliminate removing modules prematurely (before they are properly dried), and gets better use of you time when assembling drift eliminator modules.

p 9. The assembled drift eliminator packs will end up with the following dimensions + or – ¼" as set in the glue box (12" in height x 11" in width x 6'0" in length). The total amount waves that make up one assembled pack will be 16 compiled from 8 big waves & 8 small waves. Eventually these packs will be cut in half at the 11" dimension lengthways to produce two individual packs with the following dimensions (5 ½" in height x 1'0" in width x 6'0" in length).



GEA
THERMAL TECHNOLOGY DIVISION
Integrated Cooling Technologies

DWN	CLK	DWG NAME	GEA DRIFT ELIMINATOR BIG WAVE (SINGLE SHEET) UPRIGHT POSITION
CHK			
ENG			
PM			
DATE	2-22-99	SCALE NTS	DWG NO / REV



Thermal Technology Division

Integrated Cooling Technologies

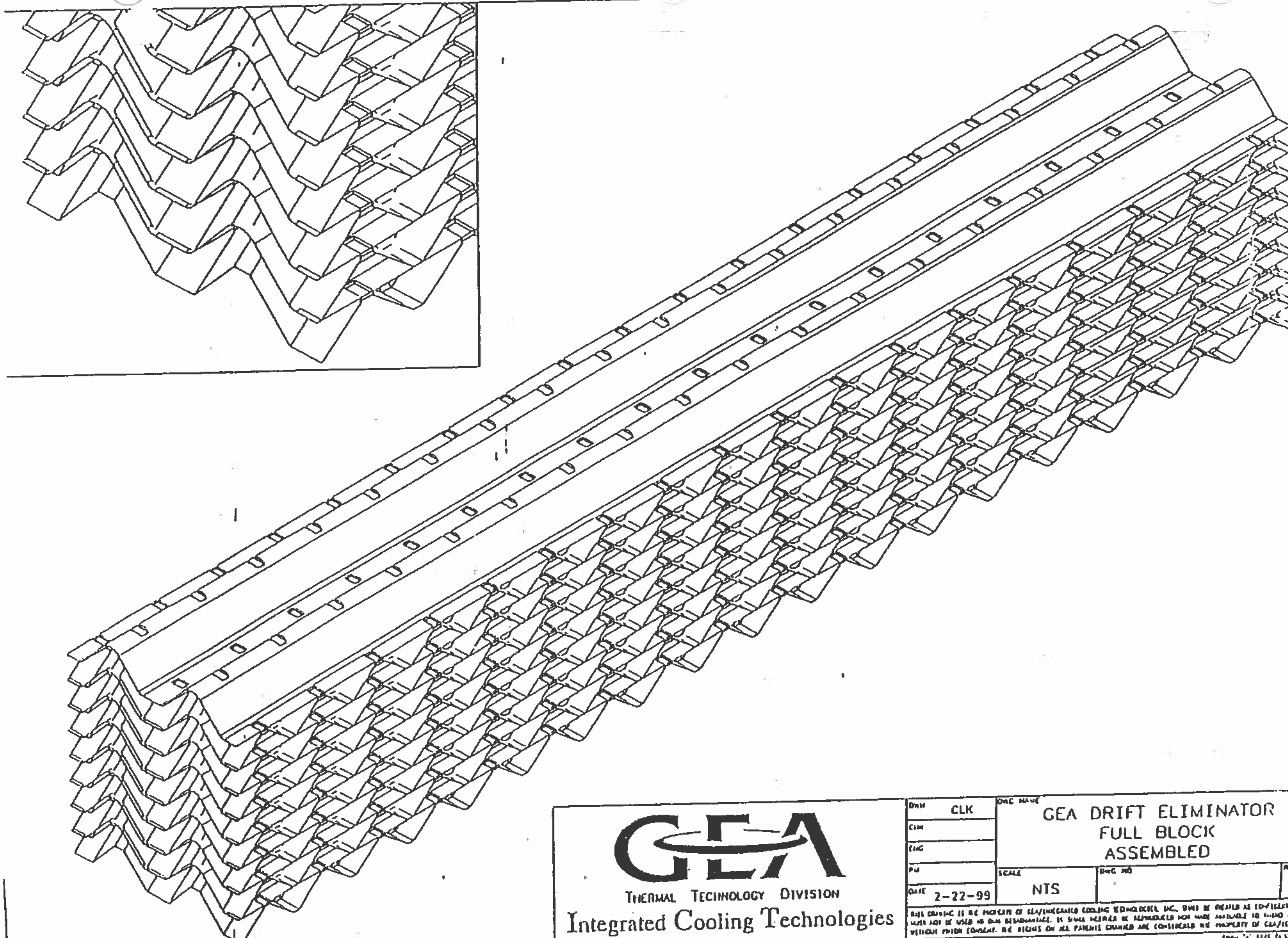
DWN	CLK
CHK	
ENG	
PM	
DATE	2-22-99

DWG NAME: GEA DRIFT ELIMINATOR SMALL WAVE (SINGLE SHEET) UPRIGHT POSITION

SCALE: NTS

DWG NO:

REV:



GEA
THERMAL TECHNOLOGY DIVISION
Integrated Cooling Technologies

DWN	CLK
CHK	
ENG	
PM	
DATE	2-22-99

DWG NAME
GEA DRIFT ELIMINATOR
FULL BLOCK
ASSEMBLED

SCALE	DWG NO	REV
NTS		

Appendix D – Compliance Assurance Monitoring Plan

COMPLIANCE ASSURANCE MONITORING PLAN
AES Hawaii, Inc.
91-086 Kaomi Loop, Kapolei, HI

June 28, 2007
005-11094-01

Prepared for
AES Hawaii, Inc.
91-086 Kaomi Loop
Kapolei, HI 96707

Prepared by
LFR Inc.
220 S. King Street, Suite 1290
Honolulu, HI 96813

TABLE OF CONTENTS

1.0 COMPLIANCE ASSURANCE MONITORING FOR BAGHOUSES CONTROLLING PM EMISSIONS FROM COAL-FIRED BOILERS

1.1 Background

Emissions Units

1.	Description:	Two 2,150 MMBTU/hr Steam Boilers
	Manufacturer:	Alhstrom Pyropower Corp.
	Identification:	N/A
	Facility:	AES Hawaii, Inc. Kapolei, Oahu, HI

Applicable Regulations, Emission Limits, and Pre-CAM Monitoring Requirements

Regulations:	Permit No. 0087-02-C: Attachment IIA, Section C Paragraphs 5 and 9, and Section D Paragraph 3; HAR 11-60.1 Air Pollution Control; Standards of Performance for New Stationary Sources, Subpart A, General Provisions; 40 CFR Part 60, Standards of Performance for New Stationary Sources Subpart Da Standards of Performance for Electric Utility Steam Generating Units;
Testing Requirement:	40 CFR Part 60, Methods 1-5 for PM; 40 CFR Part 60, Method 9 for Opacity
Emission Limits:	Particulate matter: 32.3 lb/hr from the steam boilers
Pre-CAM Monitoring Requirements:	Pressure drop meters on baghouses; opacity CEMS on boiler exhaust
Visible Emission Limit:	Boilers: 20% opacity for any 6 minute averaging period, except for one 6 minute period per hour of not more than 27% opacity.

Control Technology, Capture System, Bypass, PTE

Controls:	Baghouse
Capture System:	Closed-duct system
PTE before controls:	14,100 TPY (99% efficiency)
PTE after controls:	141 TPY

1.2 Monitoring Approach

The key elements of the monitoring approach are presented Table 1. Normal process operations will not produce conditions that adversely affect the baghouse without affecting pressure drop; therefore, no process operational parameters will be monitored.

1.3 Response to Excursion

Deviation from baghouse pressure drop thresholds and/or opacity limits will trigger an inspection of the baghouse. Maintenance personnel will inspect the baghouse immediately upon receiving notification and make needed repairs as soon as practicable. Operation will return to normal upon completed corrective action.

TABLE 1: Baghouse Monitoring Approach

	Indicator No. 1	Indicator No. 2	Indicator No. 3	Indicator No. 4
I. Indicator	Pressure drop	Inspection/ Maintenance	Source performance test for boilers	Visible Emission (VE)/ Opacity Emissions
Measurement Approach	Pressure drops through the boilers', baghouses are observed and recorded on a frequent basis using pressure drop meters.	Daily inspection according to I/M checklist; maintenance performed as needed.	Annual emissions testing using Methods 1-4 and 5.	Continuous opacity readings from the CEMS at the boilers' exhaust. Monthly opacity tests using 40 CFR Part 60, Appendix A, Method 9 or Ringelmann Chart for the coal crusher and limestone processing systems.
II. Indicator Range	Pressure drop between 1 and 9 inches of water column for the baghouses on the boilers.	NA	Opacity: 0 - 20%	Opacity: 0 – 20%
III. Performance Criteria				
A. Data Representativeness	Pressure drop across the baghouse is measured at the baghouse inlet and exhaust.	Inspections are performed at the baghouse.	Test sampling done at the exhaust of the baghouse.	VE observations/readings are indicators of PM emissions.

B. QA/QC Practices and Criteria	Pressure gauge calibrated periodically. Pressure taps checked for plugging.	Qualified personnel perform inspection.	Use reference method protocols.	QA/QC requirements of 40 CFR 60 Appendices B and F are followed to ensure proper operation of opacity CEMS;
C. Monitoring Frequency	Pressure drop is recorded daily.	Daily inspection.	Annual Testing.	Continuous VE observations.
D. Data Collection Procedures	Pressure gauge readings are recorded daily.	Records are maintained to document daily inspections and any required maintenance.	As required by Methods 1- 5.	Continuous at boilers' exhaust streams in accordance with permit CSP No. 0087-02-C, Attachment IIA, section D, paragraph 5.
F. Averaging period	None	NA	NA	1-hr

1.4 Justification

1.4.1 Background

The monitoring approach outlined here applies to the baghouses for the two steam boilers:

- Two Asea Brown Boveri baghouses control dust from two coal-fired 2,150 MMBTU per hour steam boilers. The model number is 2, and the serial numbers are 1CCB-CAB-1A and 1CCB-CAB-2A.

1.4.2 Rationale for Selection of Performance Indicators

The pressure drop across the baghouses is monitored daily. An increase in pressure drop can indicate that the cleaning cycle is not frequent enough, cleaning equipment is damaged, or the bags are becoming blinded. Decreases in pressure drop may indicate significant holes and tears or missing bags.

Implementation of a baghouse inspection and maintenance (I/M) program provides assurance that the baghouse is in good repair and operating properly.

Reference method testing for particulate will confirm the performance of the baghouse and that operation within the indicator ranges continues to assure compliance with the particulate limit.

Visible emission observations provide an immediate recognition of baghouse performance by determining the opacity level. Opacity levels greater than 20% for the boilers indicate baghouse operational issues.

1.4.3 Rationale for Selection of Indicator Range

The indicator range for the boilers' baghouse pressure drop is a pressure drop between 1 and 9 inches water. These ranges were selected based on historical data obtained during normal operation and manufacturers' recommendations. Deviation from this range indicates a potential baghouse issue.

When a problem with the baghouse is detected during an inspection, the problem is recorded on the inspection log and corrective action is initiated immediately.

Particulate matter emission limits of 32.2 lbs/hour for the boilers is included in the current CSP and was based on source test data. Other indicators were within acceptable ranges during the conduct of these tests. A visible emission limit of 20% was selected based on CSP No. 0087-02-C.

2.0 COMPLIANCE ASSURANCE MONITORING FOR SNCR SYSTEM CONTROLLING NOx EMISSIONS FROM COAL-FIRED BOILERS

2.1 Background

Emissions Unit

Description:	two 2,150 MMBTU/hr Steam Boilers
Manufacturer:	Alhstrom Pyropower Corp.
Facility:	AES Hawaii, Inc. Kapolei, Oahu, HI

Applicable Regulations, Emission Limits, and Pre-CAM Monitoring Requirements

Regulation:	Permit No. 0087-02-C, Attachment IIA, Section C, Paragraph 9 ; Section D, Paragraph 5; HAR 11-60.1 Air Pollution Control; Standards of Performance for New Stationary Sources, Subpart A, General Provisions; 40 CFR Part 60, Standards of Performance for New Stationary Sources Subpart Da Standards of Performance for Electric Utility Steam Generating Units;
Emission limits:	NO_2: 236.5 lb/hr;
Pre-CAM monitoring requirements:	NOx CEMS

Control Technology and Efficiency

Controls:	1. Selective Non-Catalytic Reduction (SNCR) with ammonia/urea injection system
SNCR efficiency:	70% reduction of NOx

2.2 Monitoring Approach

The key elements of the monitoring approach are presented Table 2. Normal process operations will not produce conditions that adversely affect the SNCR with ammonia/urea injection system without affecting the emissions from the boilers' exhaust stream; therefore, no process operational parameters will be monitored.

2.3 Response to Excursion

Excursion of emission limits will trigger an inspection of the SNCR with ammonia/urea injection system. Maintenance personnel will inspect the units upon receiving notification and make needed repairs as soon as practicable. Operation will return to normal upon completed corrective action.

TABLE 2: SNCR Monitoring Approach

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator	Output data from Continuous Emission Monitoring System (CEMS)	Inspection/maintenance of SNCR System	Source performance Test
Measurement Approach	Emissions at the boilers' exhaust streams are measured continuously for NOx, SO_2, CO_2, O_2, and opacity using the CEMS.	Periodic inspection according to manufacturer suggested I/M checklist; maintenance performed as needed.	EPA Method 1-4 and 19 for NOx
II. Indicator Range	NOx: 0 to 236.5 lb/hr	NA	NOx: 0 to 236.5 lb/hr
III. Performance Criteria			
A. Data Representativeness	Real-time NOx emissions data within acceptable range will indicate proper operation of SNCR system	Following the manufacturer's suggested I/M procedures will ensure ongoing proper operation of the SNCR system.	Test sampling done at the exhaust of the boilers.
B. QA/QC Practices and Criteria	Quarterly accuracy audits and daily calibration checks are performed in accordance with 40 CFR Part 60, Appendix F; RATA is conducted at least once a year. I/M procedures are conducted in accordance with CEMS manufacturer recommendations.	Qualified personnel perform inspections in accordance with manufacturer's suggested procedures.	Use reference method protocols.

C. Monitoring Frequency	Continuous measurements during all periods of operation; Annual RATA; and Quarterly accuracy audits.	At intervals in accordance with manufacturer's suggested procedures.	Annually
D. Data Collection Procedures	Continuous data recording during all periods of operation.	Records are maintained to document daily inspections and any required maintenance.	As required by method 1-4 and 19
F. Averaging period	1-hour	NA	NA

2.4 Justification

2.4.1 Background

The monitoring approach outlined here applies to the SNCR system for boiler NOx control. The CEMS monitors emissions of NOx, SO_2, CO_2, O_2, and opacity emissions to verify compliance with permit limits and proper operation of the SNCR system.

2.4.2 Rationale for Selection of Performance Indicators

The CEMS monitors emissions from the boilers' stack exhaust continuously. A increase in NOx emissions above indicator ranges can indicate that the SNCR system is not working properly.

2.4.3 Rationale for Selection of Indicator Ranges

The NOx indicator range for the CEMS is as follows: 0 to 236.5 lb/hr. This range was selected based on manufacturer recommendation on proper operation as well as permit limits.

When a problem with the CEMS is detected during an inspection, the problem is recorded on the inspection log and corrective action is initiated immediately.

3.0 COMPLIANCE ASSURANCE MONITORING FOR LIMESTONE INJECTION SYSTEM CONTROLLING SO2 EMISSIONS FROM COAL-FIRED BOILERS

3.1 Background

Emissions Unit

Description:	two 2,150 MMBTU/hr Steam Boilers
Manufacturer:	Alhstrom Pyropower Corp.
Facility:	AES Hawaii, Inc. Kapolei, Oahu, HI

Applicable Regulations, Emission Limits, and Pre-CAM Monitoring Requirements

Regulation:	Permit No. 0087-02-C, Attachment IIA, Section C, Paragraph 9 ; Section D, Paragraph 5; HAR 11-60.1 Air Pollution Control; Standards of Performance for New Stationary Sources, Subpart A, General Provisions; 40 CFR Part 60, Standards of Performance for New Stationary Sources Subpart Da Standards of Performance for Electric Utility Steam Generating Units;
Emission limits:	SO_2: 645 lb/hr;
Pre-CAM monitoring requirements:	SO2 CEMS

Control Technology and Efficiency

Controls:	1. Limestone injection system
SNCR efficiency:	75% reduction of NOx

2.2 Monitoring Approach

The key elements of the monitoring approach are presented Table 2. Normal process operations will not produce conditions that adversely affect the limestone injection system without affecting the emissions from the boilers' exhaust stream; therefore, no process operational parameters will be monitored.

2.3 Response to Excursion

Excursion of emission limits will trigger an inspection of the limestone injection system. Maintenance personnel will inspect the units upon receiving notification and make needed repairs as soon as practicable. Operation will return to normal upon completed corrective action.

TABLE 2: Limestone Injection System Monitoring Approach

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator	Output data from Continuous Emission Monitoring System (CEMS)	Inspection/maintenance of SNCR System	Source performance Test
Measurement Approach	Emissions at the boilers' exhaust streams are measured continuously for NOx, SO_2, CO_2, O_2, and opacity using the CEMS.	Periodic inspection according to manufacturer suggested I/M checklist; maintenance performed as needed.	EPA Method 1-4 and 6 for SO2.
II. Indicator Range	SO_2: 0 to 645 lb/hr.	NA	SO2: 0 to 645 lb/hr
III. Performance Criteria			
A. Data Representativeness	Real-time NOx emissions data within acceptable range will indicate proper operation of SNCR system	Following the manufacturer's suggested I/M procedures will ensure ongoing proper operation of the SNCR system.	Test sampling done at the exhaust of the boilers.
B. QA/QC Practices and Criteria	Quarterly accuracy audits and daily calibration checks are performed in accordance with 40 CFR Part 60, Appendix F; RATA is conducted at least once a year. I/M procedures are conducted in accordance with CEMS manufacturer recommendations.	Qualified personnel perform inspections in accordance with manufacturer's suggested procedures.	Use reference method protocols.

C. Monitoring Frequency	Continuous measurements during all periods of operation; Annual RATA; and Quarterly accuracy audits.	At intervals in accordance with manufacturer's suggested procedures.	Annually
D. Data Collection Procedures	Continuous data recording during all periods of operation.	Records are maintained to document daily inspections and any required maintenance.	As required by method 1-4 and 6
F. Averaging period	1-hour	NA	NA

2.4 Justification

2.4.1 Background

The monitoring approach outlined here applies to the limestone injection system for boiler SO2 control. The CEMS monitors emissions of NOx, SO_2, CO_2, O_2, and opacity emissions to verify compliance with permit limits and proper operation of the limestone injection system.

2.4.2 Rationale for Selection of Performance Indicators

The CEMS monitors emissions from the boilers' stack exhaust continuously. A increase in SO2 emissions above indicator ranges can indicate that the injection system is not working properly.

2.4.3 Rationale for Selection of Indicator Ranges

The SO2 indicator ranges for the CEMS is as follows: 0 – 645 lb/hr. This range was selected based on manufacturer recommendation on proper operation as well as permit limits.

When a problem with the CEMS is detected during an inspection, the problem is recorded on the inspection log and corrective action is initiated immediately.

Appendix E – Precipitation and Wind Speed Data

HONOLULU INTL AP, HAWAII

Period of Record General Climate Summary - Precipitation

Station:(511919) HONOLULU WB AIRPORT 703														
From Year=1949 To Year=2012														
	Precipitation											Total Snowfall		
	Mean	High	Year	Low	Year	1 Day Max.		>= 0.01 in.	>= 0.10 in.	>= 0.50 in.	>= 1.00 in.	Mean	High	Year
	in.	in.	-	in.	-	in.	dd/yyyy or yyyymmdd	# Days	# Days	# Days	# Days	in.	in.	-
January	3.17	13.33	1957	0.18	1986	6.40	07/1963	9	4	2	1	0.0	0.0	1950
February	2.30	13.68	1955	0.06	1983	5.52	23/1955	8	3	1	1	0.0	0.0	1950
March	2.73	20.79	1951	0.01	1957	15.32	05/1958	9	3	1	1	0.0	0.0	1950
April	1.14	8.92	1963	0.01	1960	3.90	14/1972	8	3	0	0	0.0	0.0	1950
May	0.93	7.23	1965	0.03	2000	3.44	02/1965	7	2	1	0	0.0	0.0	1950
June	0.38	2.46	1971	0.00	1959	2.00	30/1967	6	1	0	0	0.0	0.0	1950
July	0.51	2.33	1989	0.03	1950	2.18	20/1989	7	1	0	0	0.0	0.0	1950
August	0.57	3.74	2004	0.00	1974	2.92	04/2004	6	1	0	0	0.0	0.0	1950
September	0.64	2.08	1974	0.05	1977	1.35	17/1963	7	2	0	0	0.0	0.0	1950
October	1.76	11.15	1978	0.07	1996	7.47	30/1978	8	3	1	0	0.0	0.0	1949
November	2.74	18.79	1996	0.03	1962	5.39	28/1954	9	3	1	1	0.0	0.0	1949
December	3.33	17.29	1987	0.04	2002	7.89	12/1987	10	4	2	1	0.0	0.0	1949
Annual	20.20	42.78	1965	4.52	1998	15.32	19580305	95	31	10	5	0.0	0.0	1950
Winter	8.80	21.65	1988	0.90	1977	7.89	19871212	28	12	4	2	0.0	0.0	1950
Spring	4.80	21.51	1951	0.44	1993	15.32	19580305	24	8	2	1	0.0	0.0	1950
Summer	1.46	6.17	1967	0.27	2012	2.92	20040804	19	3	1	0	0.0	0.0	1950
Fall	5.15	19.64	1996	0.81	1977	7.47	19781030	24	8	2	1	0.0	0.0	1950

Table updated on Oct 31, 2012
For monthly and annual means, thresholds, and sums:
Months with 5 or more missing days are not considered
Years with 1 or more missing months are not considered
Seasons are climatological not calendar seasons
Winter = Dec., Jan., and Feb   Spring = Mar., Apr., and May
Summer = Jun., Jul., and Aug.   Fall = Sep., Oct., and Nov.

Average wind speeds are based on the hourly data from 1996-2006 from automated stations at reporting airports (ASOS) unless otherwise noted.

HAWAII

AVERAGE WIND SPEED - MPH

STATION	ID	Years	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
BRADSHAW ARMY AIRFIELD	PHSF	1996-2006	12.0	11.5	12.0	12.3	11.0	11.7	13.0	12.1	10.8	11.1	11.8	13.5	11.9
HILO INTL AIRPORT ASOS	PHTO	1996-2006	6.5	7.1	7.0	6.9	6.6	6.6	6.4	6.2	6.2	6.1	6.1	6.3	6.5
HONOLULU INTL AP ASOS	PHNL	1996-2006	8.8	9.5	9.9	11.6	10.6	12.1	12.5	12.0	10.7	10.2	9.5	9.4	10.6
KAHULUI AIRPORT ASOS	PHOG	1996-2006	11.1	11.6	11.6	13.3	12.8	15.2	15.2	14.6	13.4	12.3	11.4	11.3	12.8
KAILUA-KONA INTL AP ASOS	PHKO	1996-2006	8.4	8.4	8.4	8.2	8.1	8.1	8.2	8.3	8.0	7.8	7.9	8.0	8.1
KANEOHE BAY MCAS	PHNG	1996-2006	7.4	8.4	8.4	9.4	8.1	9.3	9.7	8.7	8.2	8.0	7.7	7.8	8.4
KAPOLEI-KALAELOA AP ASOS	PHJR	1999-2006	8.6	7.8	8.4	8.6	7.9	8.2	9.0	8.8	7.8	7.5	7.4	7.6	8.1
LAHAINA-KAPALUA AP AWOS	PHJH	1996-2006	14.4	15.1	14.9	16.7	15.7	16.9	17.1	16.8	15.8	15.1	14.2	14.6	15.6
LANAI AIRPORT	PHNY	1996-2006	9.5	10.4	10.1	11.4	10.0	10.5	12.1	11.1	10.3	9.5	10.1	9.5	10.4
LIHUE AIRPORT ASOS	PHLI	1996-2006	12.0	12.5	12.5	14.4	12.8	14.2	14.8	13.6	13.0	12.7	12.8	12.5	13.1
MOLOKAI AIRPORT ASOS	PHMK	1996-2006	10.2	10.7	10.6	12.5	11.3	13.2	14.0	13.3	11.8	11.4	10.8	10.3	11.7
WAHIAWA-WHEELER ARMY AF	PHHI	1996-2006	8.9	9.2	9.3	9.9	9.4	10.1	10.0	9.8	9.3	8.1	7.6	8.3	9.1

Source: http://www.wrcc.dri.edu/htmlfiles/westwind.final.html

Available Weather History (Wind) for Kalaeloa, HI from WeatherUnderground.com Period since last permit renewal application to determine whether any new data has higher monthly max wind speeds.		Max Month Determination
Date	Max Wind Speed (mph)	Monthly average of max wind speed
2/1/2015	13	15.32
2/2/2015	21	15.32
2/3/2015	23	15.32
2/4/2015	22	15.32
2/5/2015	24	15.32
2/6/2015	21	15.32
2/7/2015	13	15.32
2/8/2015	13	15.32
2/9/2015	18	15.32
2/10/2015	25	15.32
2/11/2015	21	15.32
2/12/2015	10	15.32
2/13/2015	21	15.32
2/14/2015	30	15.32
2/15/2015	9	15.32
2/16/2015	8	15.32
2/17/2015	9	15.32
2/18/2015	12	15.32
2/19/2015	14	15.32
2/20/2015	8	15.32
2/21/2015	12	15.32
2/22/2015	13	15.32
2/23/2015	13	15.32
2/24/2015	10	15.32
2/25/2015	10	15.32
2/26/2015	14	15.32
2/27/2015	10	15.32
2/28/2015	12	15.32

Appendix F – Stack Test Results, Specification Used Oil Content

TABLE 2-1

BOILER A TEST RESULTS

PARAMETER	UNIT	RUN 1	RUN 2	RUN 3	AVERAGE	PERMIT LIMIT
Particulate Matter/	lb/hr	4.28	4.37	4.60	4.42	32.2
PM10*	lbs/MMBtu	0.00439	0.00442	0.00471	0.00450	0.03
	gr/dscf@12% CO_2	0.00195	0.00195	0.00210	0.00200	7.0E-3
Sulfur Oxides	lb/hr	157	168	171	165	645.0
	lbs/MMBtu	0.151	0.158	0.158	0.155	1.2
	ppmvd@15%O_2	26.2	27.4	27.5	27.0	48
VOCs (as Propane)	lb/hr	1.44	0.0254	0.339	0.602	32.2
	ppmvd@15%O_2	0.349	0.00602	0.0792	0.145	3.5
Nitrogen Oxides	lb/hr	100	103	105	103	236.5
	lbs/MMBtu	0.0960	0.0965	0.0973	0.0966	0.5
	ppmvd@15%O_2	23.2	23.3	23.5	23.4	25
Carbon Monoxide	lb/hr	84.6	77.1	73.3	78.3	408.4
	ppmvd@15%O_2	32.3	28.8	27.0	29.3	70
Hydrogen	lb/hr	1.43	1.95	1.78	1.72	4.30
Chloride	lbs/MMBtu	0.00146	0.00197	0.00182	0.00175	0.002
Sulfuric Acid Mist	lb/hr	< 0.45	< 0.46	< 0.46	< 0.46	4.10
	lbs/MMBtu	< 0.000648	< 0.000752	< 0.000747	< 0.000715	1.9E-3
Fluorides	lb/hr	0.0136	0.0140	0.0137	0.0138	0.2
	lbs/MMBtu	0.0000137	0.0000140	0.0000143	0.0000140	9.3E-5
Beryllium	lb/hr	1.54E-05	2.25E-05	1.67E-05	1.82E-05	0.067
	lbs/MMBtu	1.56E-08	2.27E-08	1.69E-08	1.84E-08	3.1E-5
Lead	lb/hr	0.00164	0.00118	0.000880	0.00123	5.7
	gr/dscf@12%CO_2	7.48E-07	5.34E-07	3.99E-07	5.60E-07	1.2E-3
Mercury**	lb/hr	3.21E-05				0.17
	lbs/MMBtu	2.78E-08				1.2E-06

*PM10 emission rate assumed to be 100% of the total particulate matter (TSP) emission rate.

** Mercury results are from annual Hg LEE results conducted from March 3 to April 9, 2016.

TABLE 2-2

BOILER B TEST RESULTS

PARAMETER	UNIT	RUN 1	RUN 2	RUN 3	AVERAGE	PERMIT LIMIT
Particulate Matter/	lb/hr	12.4	8.50	11.2	10.7	32.2
PM10*	lbs/MMBtu	0.0120	0.00822	0.0115	0.0106	0.03
	gr/dscf@12% CO_2	0.00545	0.00375	0.00516	0.00479	7.0E-3
Sulfur Oxides	lb/hr	161	149	177	162	645.0
	lbs/MMBtu	0.153	0.144	0.169	0.156	1.2
	ppmvd@15%O_2	26.6	25.1	29.4	27.0	48
VOCs (as Propane)	lb/hr	0.80	0.62	0.49	0.64	32.2
	ppmvd@15%O_2	0.22	0.17	0.13	0.17	3.5
Nitrogen Oxides	lb/hr	102	98.0	103	101	236.5
	lbs/MMBtu	0.0971	0.0952	0.0988	0.0970	0.5
	ppmvd@15%O_2	23.5	23.0	23.9	23.5	25
Carbon Monoxide	lb/hr	88.9	70.1	70.0	76.3	408.4
	ppmvd@15%O_2	34.5	27.4	27.1	29.7	70
Hydrogen	lb/hr	4.78	2.37	3.51	3.551	4.30
Chloride	lbs/MMBtu	0.00462	0.00229	0.00362	0.00351	0.002
Sulfuric Acid Mist	lb/hr	< 0.231	< 0.210	< 0.207	0.116	4.10
	lbs/MMBtu	< 0.000808	< 0.000721	< 0.000723	< 0.000404	1.9E-3
Fluorides	lb/hr	0.0227	0.0280	0.0183	0.0230	0.2
	lbs/MMBtu	0.0000224	0.0000267	0.0000178	0.0000223	9.3E-5
Beryllium	lb/hr	9.37E-05	6.44E-05	6.88E-05	7.56E-05	0.067
	lbs/MMBtu	9.28E-08	6.33E-08	6.87E-08	7.49E-08	3.1E-5
Lead	lb/hr	8.46E-04	7.43E-04	8.28E-04	8.05E-04	5.7
	gr/dscf@12%CO_2	3.76E-07	3.27E-07	3.68E-07	3.57E-07	1.2E-3
Mercury**	lb/hr	2.66E-05				0.17
	lbs/MMBtu	2.22E-08				1.2E-06

*PM10 emission rate assumed to be 100% of the total particulate matter (TSP) emission rate.

** Mercury results are from annual Hg LEE results conducted from March 3 to April 9, 2016.

Specification Used Oil

	Parameter	Ash	Lead
	Limit	N/A	100
		%	ppm
1	1/3/2012	0.30	11.00
2	1/9/2012	0.38	11.00
3	1/10/2012	0.67	6.40
4	1/17/2012	0.71	9.70
5	1/31/2012	0.42	8.60
6	2/10/2012	0.48	14.00
7	2/20/2012	0.58	11.00
8	3/2/2012	0.63	8.10
9	3/8/2012	0.37	11.00
10	3/13/2012	0.50	11.00
11	3/15/2012	0.47	12.00
12	4/2/2012	0.73	10.00
13	4/12/2012	0.73	7.20
14	4/19/2012	0.76	7.50
15	4/26/2012	0.35	10.00
16	6/12/2012	0.62	6.70
17	6/14/2012	0.48	11.00
18	7/6/2012	0.36	12.00
19	8/16/2012	0.45	8.30
20	8/31/2012	0.56	5.70
21	9/20/2012	0.65	7.10
22	10/4/2012	0.36	3.20
23	10/22/2012	0.63	4.20
24	11/1/2012	0.44	8.00
25	11/16/2012	0.43	6.10
26	11/20/2012	0.66	5.80
27	11/26/2012	0.63	4.20

AVG.	0.53	8.5
LIMIT	N/A	100
MAX/MIN	0.76	14.0