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

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Background

AES Hawaii, LLC (AES) has applied for a significant modification to CSP No. 0087-02-C for its cogeneration plant to incorporate a facility-wide GHG emissions cap as defined in Hawaii Administrative Rules (HAR) §11-60.1-202. Site specific GHG emission limits were previously established in AES's GHG emission reduction plan for modifying the permit. 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 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 cap 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 emitted from affected facilities operated by HECO, HELCO, MECO, and three (3) IPPs not to exceed 7,023,258 short tons (6,371,392 metric tons) per calendar year;
2. Individual facility-wide limit on CO_2e emissions from AES's cogeneration plant 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; and
3. An equation allocating GHG emissions in excess of the total combined cap for facilities violating the individual and total combined GHG emission caps.

Affected facilities of 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 Lime Injection	Alstrom Pyropower Corporation	2,150 MMBtu/hr
Circulating Fluidized Bed Boiler B with Lime 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 process 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%
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 tons per year.

2. Baseline Emission Rate and Cap.

   Pursuant to HAR §11-60.1-204(b) and (c), AES is proposing to establish an annual facility-wide GHG emissions cap for its cogeneration plant as shown in the table on page 9 of this permit application review. 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. The combined emissions cap was determined by multiplying the total combined baseline GHG emissions (less any biogenic CO_2 emissions) for partnering facilities by 0.84 (1.0-0.16).

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 sixteen percent (16%) GHG reduction from the established GHG baseline is met.

The combined emissions cap will be made part of the permit for each partnering facility pursuant to HAR §11-60.1-204(d)(6)(C) and must be achieved by 2020 and maintained thereafter. 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 greenhouse gas, 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 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).

The total combined GHG baseline and GHG emission caps proposed for the partnering facilities are as follows:

Actual GHG Baseline and Proposed 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)	Proposed	
AES	0087-02-C	1,681,605	0	1,681,605	1,691,605	-0.6%
Hamakua	0243-01-C	182,975	0	182,975	153,699	16.0%
Kalaeloa	0214-01-C	1,094,813	0	1,094,813	1,094,813	0%
HECO CIP	0548-01-C	19,179	4,233	14,946	53,740	-259.6%
HECO Honolulu [a]	0238-01-C	133,609	0	133,609	0	100.0%
HECO Kahe	0240-01-C	2,776,073	0	2,776,073	2,133,752	23.1%
HECO Waiau	0239-01-C	1,074,359	0	1,074,359	808,286	24.8%
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	0232-01-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 [b]	7,023,257 [b]	16.0%

[a]The HECO Honolulu Generating Station is currently deactivated (not operating but could restart if necessary).
[b]Total combined partnering facility proposed GHG baseline and GHG emission cap are 8,361,022 and 7,023,258 short tons, respectively. Totals may not sum due to independent rounding.

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 is the same as that proposed by partnering facilities that have combined their facility-wide emission caps in meeting a combined GHG emission cap in accordance with HAR Subparagraph 11-60.1-204(d)(6)(A). Please refer to the table titled “Actual Baseline and Proposed CO_2e Facility Emission Caps” on Page 10 of this permit application review. The total combined CO_2e emissions in the table below for the notional cap are 7,023,258 short tons per year. The total combined CO_2e emission level proposed, as shown in the table on Page 10, is 7,023,258 short tons per year.

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	1,074,359	0	1,074,359	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	0232-01-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	8,361,021	7,023,258	16.0%

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

The CAB also 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 data is 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 0.855% 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 of more electricity than 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.

Federal Requirements:

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 combined CO_2 emissions 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. 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.

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
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	1,040	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).

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		5.66				1,040
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
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

Pollutant	Steam Boilers [1] (TPY)	Coal Processing (TPY)	Limestone Processing (TPY)	Ash Handling (TPY)	Cooling Tower (TPY)	Storage Tanks (TPY)	Total (TPY)
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)	229	25	5,725	5,194
Nitrous Oxide (N_2O)	33.3	298	9,923	9,002
Maximum Potential CO_2e Emissions			2,190,308	1,987,014

AES is proposing an individual CO_2e emissions cap of 1,691,605 short tons (1,534,598 metric tons) per calendar year for its coal fired cogeneration plant. This individual cap is an approximate 0.6% increase from the facility's baseline 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 start of 2020.

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. 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.

Generating Station	CSP Permit No.	CO_2e Emission Cap	
		Metric Tons per Calendar Year	Short Tons per Calendar Year
AES Coal-Fired Cogeneration Plant	0087-02-C	1,534,598	1,691,605
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	139,433	153,699
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	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)

Reason: Required by HAR §11-60.1-204(d)(6)(A).

2. All partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of 6,371,392 metric tons (7,023,258 short tons) per calendar year.

   Reason: Required by HAR §11-60.1-204(d)(6)(A).

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 emissions 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. Total combined emissions cap cannot be less than sixteen percent (16%) of total combined baseline emission.

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. By **August 29, 2019**, and **within sixty (60) days** following the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31) thereafter**,** the AES coal-fired cogeneration plant shall submit written reports to the Department for monitoring CO_2e emissions to verify compliance with:

   a. The individual GHG emissions cap and allocating excess emissions pursuant to Attachment II – GHG, Special Condition No. C.1.c.v; and
   b. The total combined GHG emissions limit and allocating excess emissions pursuant to Attachment II – GHG, Special Condition No. C.1.c.v.

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

<u>Conclusion and Recommendation</u>

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.

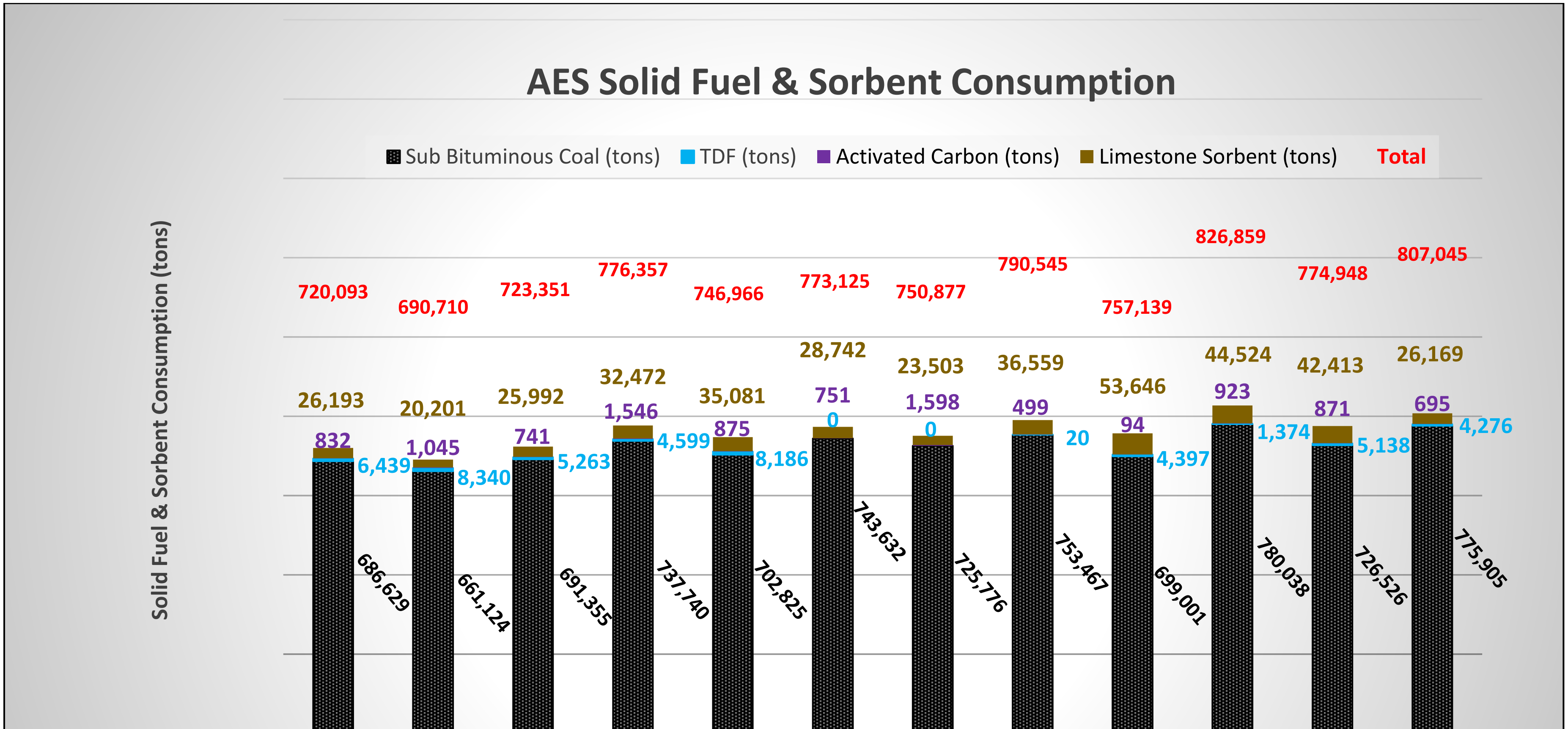
The HECO, HELCO, MECO, and IPP plants are proposing a sixteen percent (16%) GHG emissions reduction from the total combined baseline GHG emissions; and to use a total combined GHG emission cap by partnering pursuant to HAR §11-60.1-204(d)(6)(A).

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. 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
March 14, 2019

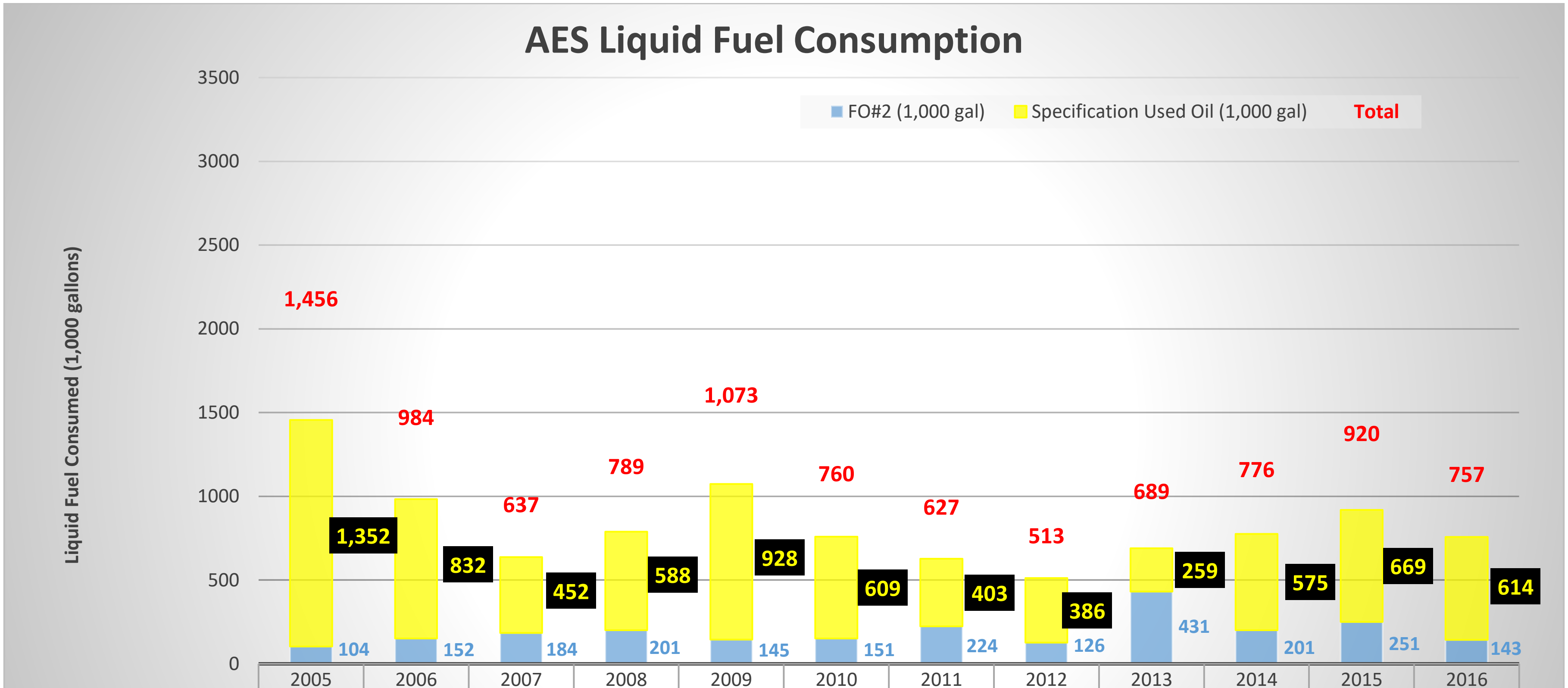
ENCLOSURE 1



	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

AES														
SOLID FUEL-LIME SORBENT CONSUMPTION DATA														
Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(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

Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AES														
LIQUID FUEL CONSUMPTION DATA														
(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

Ref	Source Derivation	Calendar Year ->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CALCULATE CO_2e EMISSIONS AND COMPARE WITH BASELINE IN GHG REDUCTION PLAN														
(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)						1,534,598						
(d)		**Deviation from CAB Calculations**						**0.855%**						
(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+0.006)*((e)-(g))	2020 CO_2e Emissions Cap (tons)	1,580,555	1,522,440	1,579,113	1,686,790	1,616,527	1,687,320	1,541,402	1,594,657	1,489,729	1,773,047	1,661,787	1,768,818
(j)	AES GHG Plan	AES CO_2e Emissions CAP (tons)						1,691,605						
	(i)-(j)	Low er (-) or Higher than CAB Estimate (tons)						4,285						

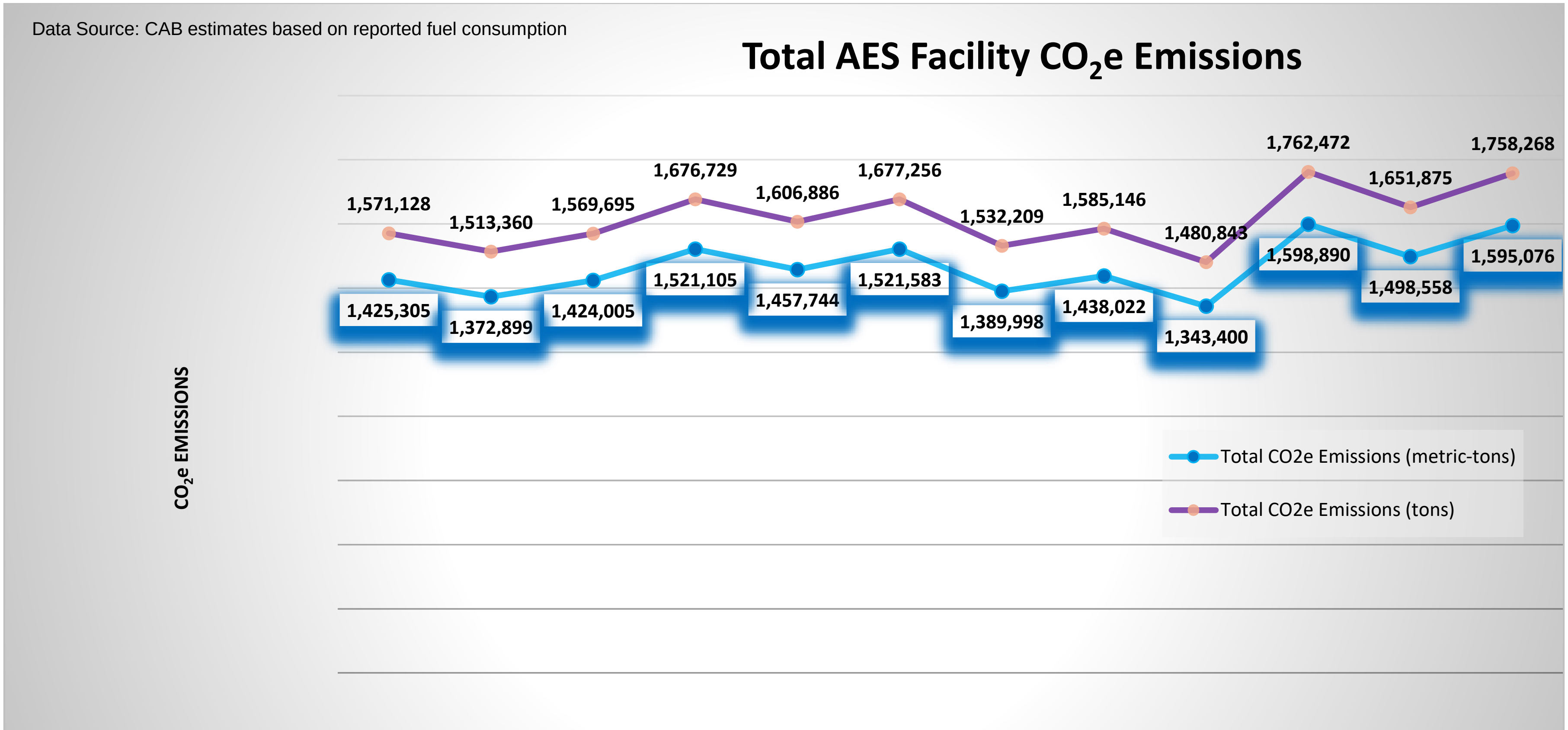
a: Based on information from https://w w w .betalabservices.com/renew able-carbon/tire-derived-fuels.html that biomass fraction of scrap tires are 18.3% on average for used passenger car tires and 29.1% on average for used truck tires. The average of the tw o percent averages is 23.7%. The percentages of biomass in the tire dirived fuel (TDF) w as 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.

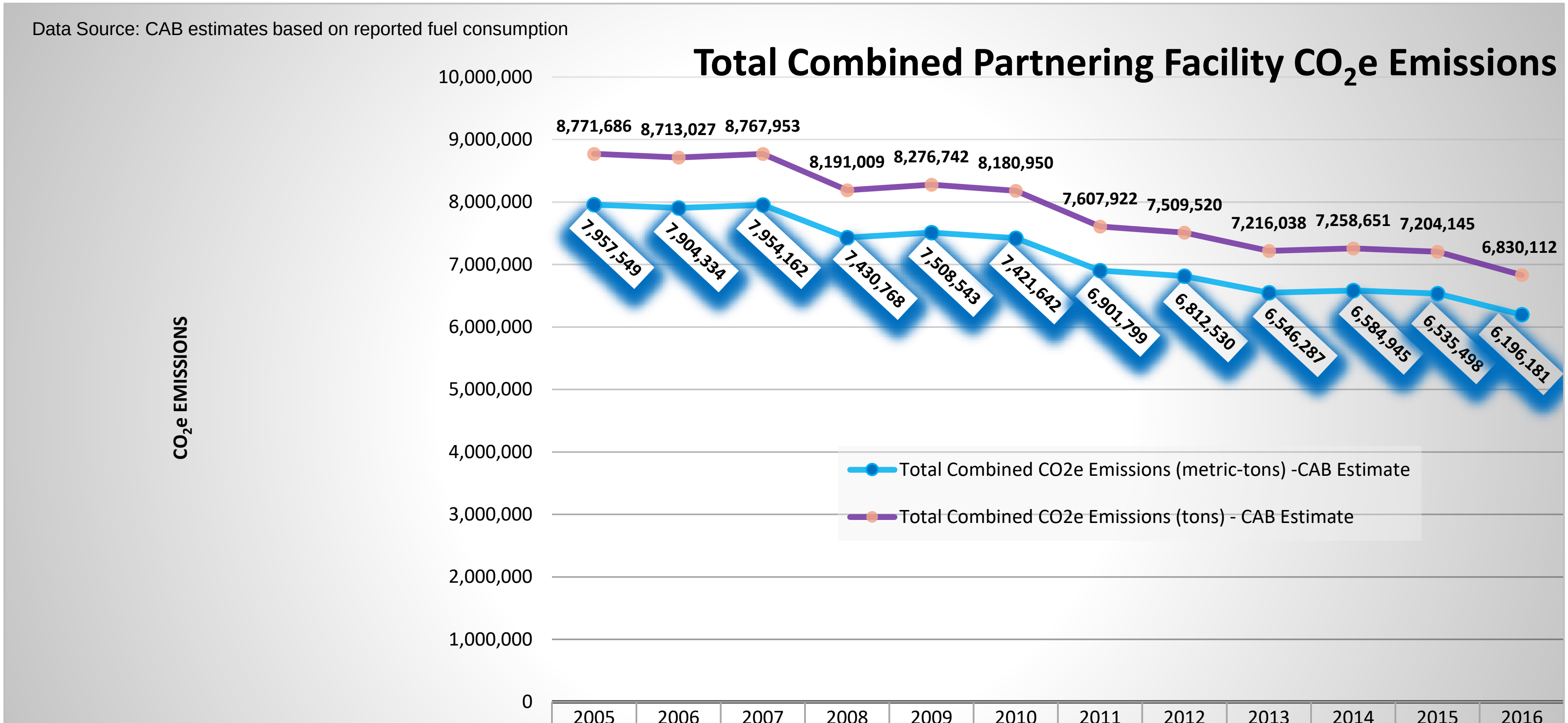
ENCLOSURE 7

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+0.006)*(a)	2020 CO_2e Emissions Cap (metric-tons)						1,530,712						
(d)	(1.00+0.006)*(b)	2020 CO_2e Emissions Cap (tons)						**1,687,320**						
(e)	AES GHG Plan	AES Baseline Emissions (tons)						1,681,605						
(f)	AES GHG Plan	AES CO_2e Emissions CAP (tons)						1,691,605						
(g)	(f)-(d)	Higher or Lower (-) than CAB Estimated Cap (tons)						4,285						
(h)	(g)/(d)	Higher or Lower (-) than CAB Estimated Cap (%)						0.25%						

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.