Significant Modification to a Covered Source Permit Review Summary

Application File No.:	0087-05
Permit No.:	0087-02-C
Applicant:	Applied Energy Services (AES) Hawaii, Inc.
Facility:	203 MW Coal-Fired Cogeneration Plant Located at 91-086 Kaomi Loop, Campbell Industrial Park, Kapolei, Oahu
Mailing Address:	AES Hawaii, Inc. 91-086 Kaomi Loop Kapolei, Hawaii 96707
Responsible Official:	Mr. Jeff Walsh President and General Manager Ph: 682-5330
Point of Contact:	Richard Aust NAW Environmental Manager Ph. (713) 740-2215
Application Date:	Received on July 15, 2011, Additional information dated November 4, 2011 and January 24, 2012.

Proposed Project:

SICC: 4911 (Electric Services)

General Information
The AES Hawaii, Inc. (AES) facility is a 203 MW (maximum), 180 MW (nominal) coal-fired cogeneration plant. This facility is located at Campbell Industrial Park on the southwest corner of Oahu, approximately 3,000 feet north of Barbers Point.

Proposed Modification
AES Hawaii, Inc. proposes to authorize an additional fuel (biomass) for use in its steam boilers at its cogeneration plant in Kapolei. The boilers are currently authorized to burn coal, spec. used oil, spent activated carbon, distillate oil, and tire-derived fuel to produce up to 203 MW of power.

The existing boilers, fuel feed systems, and ash handling systems can accommodate the biomass fuel without any physical modifications. The preparation of the biomass fuel (grinding, chipping, drying, etc.) will be completed off-site, and the biomass will be handled primarily in the same systems used to transport and store coal. The total authorized production capacity for the plant is unchanged; rather the biomass fuel will displace the use of other authorized fuels.

Although the existing fuel feed systems could accommodate biomass, some minor changes to the feed system will be made to support improved monitoring and metering of biomass feed rate. These modifications are necessary only to provide an auditable means of accounting for biomass consumption because the market requirements for power produced from renewable fuels. Changes to the feed system may include the following changes:

- Addition of a day bin for biomass fuel;
- Addition of separate pneumatic feed system to allow for the addition of biomass to coal just prior to combustion in the boilers; and
- Potential addition of one or two additional small baghouses to control pneumatic conveyance of biomass.

The emissions characteristics for biomass are generally more favorable than the other fuels. A brief summary of the impacts resulting from the authorization of biomass are as follows:

- The biomass fuel is considered greenhouse gas neutral (unlike the authorized fossil fuels). The single most significant impact from the proposed project is a reduction in fossil-fuel CO_2 emissions;
- The biomass has significantly lower sulfur content than other authorized fuels;
- The biomass has significantly lower metals content than other authorized fuels;
- The biomass has significantly lower fuel-bound nitrogen content than other authorized fuels;
- The biomass fuel may contain a higher percentage of chlorine than currently authorized fuels;
- The increased chlorine content may result in increases of hydrogen chloride (HCl) and dioxins emissions; and
- Published emissions factors for other hazardous air pollutants from biomass combustion differ than those published for the other authorized fuels.

A test burn of biomass fuel was conducted in 2011 which demonstrated no observable increase in pollutants currently measured with the site's Continuous Emissions Monitoring System (NO_x and SO_2). Sampling was also conducted during the test burn to evaluate the effectiveness of existing emissions control for HCl emissions.

Please note that although chlorine is present in the currently authorized fuels at the plant, the HCl emissions resulting from their combustion had not been previously quantified and incorporated into the permit. As a result, the applicant has included an emissions estimate with this application for HCl emissions from the combustion of currently authorized fuels as a correction to the existing permit.

Based on the results of the test burn, comparing fuel analyses, and available published emission factors, emissions calculations have been completed for the combustion of the biomass fuel. While no increases in emissions in authorized emission rates are projected for any criteria pollutants, the potential increase in HCl emissions exceeds 500 lbs/yr, making this application a significant modification to the covered source permit.

This application proposes the addition of another alternative fuel. Biomass is prepared off-site and is received in bulk or in bales. Biomass will be stored onsite in piles and/or stacked bales. Emissions associated with material handling of biomass will be insignificant due to the moisture content and the material properties of biomass. In addition, particulate emissions from the blending of biomass and coal will not exceed the represented emission rates for coal handling.

Air dispersion modeling has been completed and is being submitted concurrently with this application. The modeling demonstrates that no adverse impacts are anticipated as a result of the proposed modification.

An application fee of $3,000 for a significant modification application was submitted and processed.

Estimated Throughput Limits for Permit Basis

Fuel	Represented Heating Value (Btu/lb)	Maximum Throughput (lb/hr)	Maximum Heat Input (MMBtu/hr)	Throughput Scenario 1	Throughput Scenario 2	Throughput Scenario 3	Throughput Scenario 4
Coal	10,000	215,000	2150	215,000	200,000	193,501	178,501
TDF	10,000	15,000	150	0	15,000	0	15,000
Wood	5,500	39,090	215	0	0	39,090	39,090
Total (lb/hr)				215,000	215,000	232,591	232,591
Combined Heat Input (MMBtu/hr)				2150	2150	2150	2150
Rounding (lb/hr)				215,000	215,000	233,000	233,000

Maximum Permit Allowable Heat Input (combined) = 2,150 MMBtu/hr

Equipment Description:

1. Two (2) boilers A and B manufactured by Alhstrom Pyropower Corporation.

    a. Total maximum design heat input of 2,150 MMBtu/hr fired on coal, TDF, fuel oil no. 2, spec. used oil, spent activated carbon and biomass (proposed modification).
    b. Air pollution control devices for the boiler are low-temperature staged combustion, selective non-catalytic reduction (SNCR) with ammonia/urea injection (Thermal DeNO_x), limestone injection, and two (2) baghouses (ABB Flakt Model 2). The combined emissions flow through one stack.
    c. 25,000 gal pressurized anhydrous ammonia storage tank.
    d. Fuel use:

        i. Coal – The maximum annual consumption of coal (<1.5% S by wt) in the boilers is 941,700 tons/yr based on the normal coal feed rate of 107.5 tons/hr (on a dry basis) for 8760 hrs/yr.
        ii. TDF – The maximum annual consumption of TDF in the boilers is 65,700 tons/yr based on the permitted TDF feed rate of 7.5 tons/hr for 8760 hrs/yr. TDF is fed to the boilers mixed with coal at a combined feed rate not to exceed 215,000 lbs/hr (107.5 tons/hr)(on a dry basis).
        iii. Spec. Used Oil – A maximum of 3,000,000 gallons of spec used oil may be fed into the boilers during any rolling 12-month period.
        iv. Spent Activated Carbon – Activated carbon has similar characteristics as coal. No limit is included in CSP No. 0087-02-C for this type of fuel.
        v. Fuel Oil No. 2 (≤ 0.5% S by wt) – Used to support combustion operations during hot or cold startups. Based on historical records, the maximum fuel oil no. 2 annual consumption for the boiler is 475,000 gal/yr.

vi. Biomass (wood) – The maximum annual consumption of biomass in the boilers is 175,200 tons/yr based on an hourly feed rate of 20 tons/hr (on a dry basis) for 8760 hrs/yr. Biomass is fed to the boilers mixed with coal at a combined feed rate not to exceed 233,000 lbs/hr (116.5 tons/hr)(on a dry basis).

vii. Mixture of coal, TDF and biomass at a combined feed rate not to exceed 233,000 lbs/hr (116.5 tons/hr)(on a dry basis).

2. Coal processing

    a. Overland coal conveyor from the deep draft harbor to the stockpiles.
    b. Two (2) coal lowering wells.
    c. Four (4) coal conveyors.
    d. Coal reclaim hopper.
    e. 275 tph coal crusher
    f. Four (4) coal storage silos.
    g. Mikro-Pulsaire baghouse for the coal crusher (model no. 64S-12-40).

3. Limestone processing

    One (1) Limestone storage hopper with two (2) complete Micron Powder Systems Limestone Processing Systems each with a maximum feed rate of 22 tph and each consisting of the following equipment:

    a. Limestone feeder.
    b. 4.75 MMBtu/hr limestone dryer (1A and 1B). Fired on fuel oil no. 2 and spec used oil.
    c. Mikro pulverizer (model no. 300 ACM).
    d Mikro-Pulsaire baghouse (model no. 420S-10-50 “C”).
    e. Conveyors.

4. One (1) GEA Integrated Cooling Technologies, Inc. five-cell induced draft cooling tower (model no. 545438-5l-32FCF) - 104,000 gal/min, maximum drift rate 0.002%.

5. Ash handling
    a. Fly Ash Reinjection Surge Hopper
    b. Bed Ash Storage Hopper
    c. One (1) Fly Ash Silo
    d. One (1) Bed Ash Silo
    e. Aggregate Mixer

6. One (1) 60,000 gal fuel oil no. 2 above ground fixed roof storage tank - 18 ft high, 24 ft diameter, cone roof, with white shell (230.7 m^3).

Air Pollution Controls:

<u>CFB Boilers</u>

1. SNCR with Ammonia Injection (70% NO_x reduction)
    NO_x emissions are further 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, Thermal $DeNO_x$ designed and manufactured by Alhstrom Pyropower, is capable of meeting 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 down 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. Limestone injection also acts to control HCl emissions.

3. Good Combustion
   Proper boiler operation and good combustion practices will help control PM, PM_{10}, CO, and VOC emissions. Also, low temperature-staged combustion design of the boilers reduces NO_x emissions. SO_2 is also controlled by using coal with a maximum sulfur content of 1.5% by weight.

<u>Baghouses (99.99% PM/PM_{10} reduction)</u>
PM/PM_{10} and opacity are controlled by the use of the baghouses shown in the table below:

Emissions Unit	Baghouse (No./Manufacturer/Model)	Operating Pressure
Boilers	2/Asea Brown Boveri/2	1-9" H_2O
Limestone Driers/Crushers	2/Mikro-Pulsaire/420S-10-50 H1/H2	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-12-40	1-7" H_2O
Coal Storage Silos *	1/Mikro-Pulsaire/100S-12-40	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
Biomass Conveyance	2/To be determined/To be determined	1-7" H_2O

* Baghouses that are insignificant since estimated emissions are small.

<u>Fugitive Dust Suppression</u>
Fugitive dust is controlled using the methods shown in the table below throughout the facility:

Emissions Unit	Control	Expected Efficiency
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:

Hawaii Administrative Rules (HAR)
- Title 11 Chapter 11-59, Ambient Air Quality Standards
- Title 11 Chapter 11-60.1, Air Pollution Control
  - Subchapter 1, General Requirements
  - 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
  - Subchapter 5, Covered Sources
  - Subchapter 6, Fees for Covered Sources
    - 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
  - Subchapter 7, Prevention of Significant Deterioration
  - Subchapter 8, Standards of Performance for Stationary Sources
  - Subchapter 9, Hazardous Air Pollutants
  - Subchapter 10, Field Citations

40 Code of Federal Regulations (CFR) Part 60 - New Source Performance Standard (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

40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)
Subpart A – General Provisions
Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units

Non-Applicable Requirements:
40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)
Subpart Q – National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers
This cooling tower is not subject to NESHAPS, Subpart Q, because it did not use chromium-based water chemicals at the time this NESHAPS was promulgated, nor does AES use this chemical at the present time.

Prevention of Significant Deterioration (PSD):

40 CFR 52.21 - Prevention of Significant Deterioration of Air Quality (PSD) is applicable to the cogeneration facility according to the previous terms and conditions that were a part of PSD No. HI 88-02.

No new PSD review is applicable to the facility as shown in the table below. There is no increase in emissions of criteria pollutants associated with the combustion of biomass in the boilers because the overall capacity of the units and the authorized emissions will remain unchanged.

Period	PM_{10}	SO_2	CO	NO_X	VOC
(--)	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**
2009	127.50	1,769.60	544.80	746.30	22.86
2010	128.10	1,794.00	546.60	758.90	22.85
Baseline[2]	141.00	2,830.00	1,790.00	1,038.00	141.00
Current MAER	141.00	2,830.00	1,790.00	1,038.00	141.00
Proposed MAER	141.00	2,830.00	1,790.00	1,038.00	141.00
Actual to Potential[3]	0	0	0	0	0

[1] MAER - Maximum Allowable Emission Rate limit from Covered Source Permit
[2] Baseline = The baseline has been adjusted to reflect the allowable emission rates that were relied upon in issuing the existing PSD permit. Any creditable increase would have to exceed the current allowable emission rates.
[3] Actual to Potential = Proposed MAER – Baseline

The regulatory basis for non-applicability of PSD for criteria pollutant emissions associated with this project is as follows:

- Per 40 CFR 52.21(a)(2)(ii), PSD requirements apply to the construction of any new major stationary source or the major modification of any existing major stationary source.

- In 40 CFR 52.21(b)(2)(i) Major modification is defined as *"any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source."*
- In 40 CFR 52.21(b)(3)(iii)(a), increases or decreases are creditable for the determination of *Net emissions increase* only if *"The Administrator or other reviewing authority has not relied on it in issuing a permit for the source under this section, which permit is in effect when the increase in actual emissions from the particular change occurs".*

In the case of this project, the site is a major stationary source and the operational changes qualify as a modification; however, the changes do not qualify as a major modification because there is no significant net emissions increase. The proposed project will not result in an increase in actual emissions beyond possible demand growth in power consumption. Increases in emissions resulting from demand growth are excluded from consideration as the unit does not require physical modifications to meet the demand and the facility has an issued PSD covered source permit covering the physical capacity of the facility. Furthermore, the difference between past actual and proposed (but unchanged) allowable emissions is not a creditable increase because the full allowable emission rates were authorized in the original PSD permit. Furthermore, the only increases in emissions associated with this application are for HCl and other HAPs which vary from the emissions associated with coal or other fuels already authorized at the site. These pollutants are not considered regulated NSR pollutants pursuant to PSD based on the following citation.

> *40 CFR 52.21(b)(50)(v) Notwithstanding paragraphs (b)(50)(i) through (iv) of this section, the term regulated NSR pollutant shall not include any or all hazardous air pollutants either listed in section 112 of the Act, or added to the list pursuant to section 112(b)(2) of the Act, and which have not been delisted pursuant to section 112(b)(3) of the Act, unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.*

The project is expected to result in a decrease in net greenhouse gas emissions. This is because the biomass combusted is from a renewable source, and are used as an alternative to fossil fuels. EPA has clarified that biomass combustion is not currently subject to PSD for greenhouse gas emissions in the signing of a final rule on July 1, 2011. The rule defers for a period of three (3) years the application of the Prevention of Significant Deterioration (PSD) and Title V permitting requirements to biogenic carbon dioxide (CO_2) emissions from bioenergy and other biogenic stationary sources. During this three year period biogenic CO_2 emissions are not required to be counted for applicability purposes under the PSD and Title V permitting programs. State, local, and tribal permitting authorities may adopt the deferral at their option but the deferral is effective upon publication for the PSD and Title V permit programs that are implemented by EPA. EPA encourages states to adopt and implement the deferral as part of delegated GHG permitting programs.

Best Available Control Technology (BACT):

As defined in HAR §11-60.1-1, a Best Available Control Technology (BACT) review is required for new or modified sources that trigger "significant" emission limits. No new or modified sources that trigger "significant" emission limits are proposed as part of this application.

The only new or modified sources or physical modifications to existing sources that are proposed with this application are the changes to the fuel feed system to allow for more accurate metering and accounting of biomass. The sources of emissions associated with changes are insignificant under HAR §11-60.1-82(f)(7) with potential emissions less than 2 tons/yr of each regulated pollutant.

The operational changes associated with using biomass as an alternative authorized fuel may result in a "significant" increase. The facility proposes to meet BACT by complying with the MACT emission limitation for HCl (0.002 lb/MMBtu) for coal-fired boilers (which includes co-firing of biomass). Because the MACT standard, at minimum, must be set at BACT levels, this emission limit has been established at a federal level as meeting or exceeding BACT. The facility will demonstrate compliance as required by the MACT standard and will meet the emissions limitation using existing emissions controls, including limestone injection.

Current BACT requirements, implemented by PSD Permit HI 88-02, include the following:

1. Limestone injection into the fluidized bed to reduce SO_2;
2. SNCR to reduce NO_x;
3. Good combustion practices to reduce CO, VOC, and hazardous air pollutant vapors; and
4. Baghouse/fabric filters to reduce PM and hazardous air pollutant particles.

Compliance Assurance Monitoring (CAM):

CAM is to provide a reasonable assurance that compliance is being achieved with large emissions units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 Code of Federal Regulations, 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 precontrol emissions that are greater than the major source level [>100 tpy]; and (5) not otherwise be exempt from CAM. CAM is applicable to the boilers for SO_2, NO_2, and PM since items 1 through 5 above apply. AES has met CAM requirements with the use of CEMS for SO_2, NO_x, and opacity. Monitoring opacity is sufficient since opacity is a direct correlation to PM emissions.

The CAM plan for the facility is not being changed with this application. The emissions of HCl are exempt from CAM because CAM does not apply to emission limitations or standards proposed by the EPA after November 15, 1990 under the Federal Clean Air Act Chapter 111 (Standards of Performance for New Stationary Sources) or Chapter 112 (Hazardous Air Pollutants). In this case, the standard in 40 CFR 63 Subpart UUUUU was proposed by EPA after November 15, 1990 and regulates the emissions of HCl.

Consolidated Emissions Reporting Rule (CERR)/In-house Reporting Applicability:

40 CFR Part 51, Subpart A – Emission Inventory Reporting Requirements, determines CER based on the emissions of criteria air pollutants from Type A or Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the CER triggering levels as shown in the table below.

Pollutant	Type A CERR Trigger Level [1,3] (tpy)	Type B CERR Trigger Level [1] (tpy)	Pollutant	In-house Total Facility Trigger Level [2] (tpy)	Total Facility Emissions (tpy)
NO_x	≥ 2500	≥ 100	NO_x	≥ 25	1040.66
SO_x	≥ 2500	≥ 100	SO_x	≥ 25	2841.53
CO	≥ 2500	≥ 1000	CO	≥ 250	1790.75
PM			PM	≥ 25	350.62
PM_{10}	≥ 250	≥ 100	PM_{10}	≥ 25	350.62
$PM_{2.5}$	≥ 250	≥ 100	$PM_{2.5}$		350.62
VOC	≥ 250	≥ 100	VOC	≥ 25	141.13
Pb	≥ 5	≥ 5	Pb	≥ 5	25.0
			HAPS	≥ 5	26.90

[1] Based on actual emissions
[2] Based on potential emissions
[3] Type A sources are a subset of the Type B sources and are the larger emitting source by pollutant

This facility emits above the CER triggering levels. Therefore, CER requirements are applicable.

The Clean Air Branch also requests annual emissions reporting from those facilities that have facility-wide emissions of a single air pollutant exceeding in-house triggering levels. Annual emissions reporting is required for this facility for in-house recordkeeping purposes because it is a covered source and facility-wide emissions of NO_x, SO_x, CO, PM/PM_{10}, VOC, Pb and HAPS exceed in-house triggering levels.

Insignificant Activities:

The following equipment are insignificant sources:

1. Three (3) 300 gal above ground storage tanks, insignificant per HAR §11-60.1-82(f)(1);
2. Emergency generator and emergency boiler feedwater pump, insignificant per HAR §11-60.1-82(f)(5);
3. Fuel burning equipment with a total heat input of less than 1 million Btu/hr, insignificant per HAR §11-60.1-82(f)(2);
4 Hand held equipment for various purposes, insignificant per HAR §11-60.1-82(g)(2);
5. Laboratory equipment used for chemical and physical analysis, insignificant per HAR §11-60.1-82(g)(3);
6. Mobile generators, air compressors, welders, and pressure washer, insignificant per HAR §11-60.1-82(d)(4);
7. Fire fighting system, insignificant per HAR §11-60.1-82(g)(6);
8. One (1) 17,631 gallon spec used oil tank, insignificant per HAR §11-60.1-82(f)(1);
9. One (1) 25,000 gallon pressurized anhydrous ammonia storage tank, insignificant per HAR §11-60.1-82(f)(1);
10. Four (4) limestone feeders, each is equipped with a baghouse, insignificant per HAR §11-60.1-82(f)(7);

11. One (1) pulverized limestone storage hopper services with a baghouse, insignificant per HAR §11-60.1-82(f)(7);
12. Fabric filter/baghouses associated with solid fuel conveyance, insignificant per HAR §11-60.1-82(f)(7); and
13. Biomass handling operations, insignificant per HAR §11-60.1-82(f)(7).

Alternate Operating Scenarios:

1. Haul trucks may be used to transport coal to the facility in lieu of the covered overland conveyor. Fugitive emissions should be similar for both scenarios since the added paved road will be offset with the subtraction of the overland conveyor, lowering wells, and conveyor 1.
2. Alternative fuels were proposed as alternate scenarios, but they will be considered as normal operations since the emissions were calculated as such and are used intermittently with coal.
3. The permittee may stockpile a maximum of 10,000 tons of conditioned ash at any given time in the facility's workyard in the event the ash silos reach their maximum capacity.

Synthetic Minor Source:

A synthetic minor source is a source that is potentially major (as defined in HAR §11-60.1-1), but is made nonmajor through federally enforceable permit conditions. This facility is not a synthetic minor source because it is a major source (potential to emit ≥100 tpy).

Project Emissions:

The primary emissions from the boiler consist of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO) and volatile organic compounds (VOC). Lesser amounts of hazardous air pollutants (HAPs) are also emitted from the boiler.

The potential emissions from the coal combustion in the boilers were derived from source performance test data and continuous emissions monitoring systems (CEMS). All other potential emissions for fuel oil combustion in the boilers were based on AP-42 emission factors.

The following table contains the maximum permitted emission rates for the boilers' stack as referenced from PSD HI 88-02 and NSPS Da. Hydrogen chloride (HCl) emission factors are proposed in this application based on 40 CFR Part 63, Subpart UUUUU.

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	8.1E-5	--	--
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^{0}F 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^{0}F 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.

Potential Emissions Calculations from Boilers Fired with Coal

Parameters	Value	Unit	Source
Coal HHV	10,000	Btu/lb	Average Value
Operating Hours	8,760	hr/yr	24 hours per day operating 365 days per year
Maximum Hourly Coal Heat Input	2,150	MMBtu/hr	Approximately 20 MW production
Annual Coal Heat Input	18,834,000	MMBtu/yr	8760 hrs operation with coal heat input
Maximum Hourly Coal Fuel Consumption	107.5	tons/hr	Coal HHV/Max Heat Input
Annual Coal Fuel Consumption	941,700	tons/yr	8760 hrs operation with maximum consumption

Potential Emissions Calculations from Boilers Fired with Biomass

Parameters	Value	Unit	Source
Biomass HHV	5,500	Btu/lb	Ahistrom Technical Report dated January 11, 2011
Operating Hours	8,760	hr/yr	24 hours per day operating 365 days per year
Maximum Hourly Biomass Heat Input	215	MMBtu/hr	Approximately 20 MW production
Annual Biomass Heat Input	1,883,400	MMBtu/yr	8760 hrs operation with biomass heat input
Maximum Hourly Biomass Fuel Consumption	20	tons/hr	Biomass HHV/Max Heat Input
Annual Biomass Fuel Consumption	175,200	tons/yr	8760 hrs operation with maximum consumption
Baghouse Control Efficiency	99	% control	Applies to Metals – Excludes Mercury

The following table contains the boilers maximum potential annual emissions for coal and wood firing based on operating 8,760 hr/yr with air pollution controls:

Pollutant	Steam Boilers Coal (lb/hr)	Steam Boilers Coal (tpy)	Steam Boilers Wood (lb/hr)	Steam Boilers Wood (tpy)
SO_x	645	2830		
NO_x	237	1038		
PM	32	141		
CO	408	1790		
VOC	32.2	141		
Lead	32.2	25.0		
Mercury	0.2	0.745		
Beryllium	0.07	0.293		
Fluorides	0.2	0.876		
Sulfuric Acid Mist	4.1	18.0		
Hydrogen Chloride (HCl)	4.30	18.83	0.43	1.88
Acetaldehyde			1.78E-01	7.82E-01
Acetophenone			6.88E-07	3.01E-06
Acrolein			8.60E-01	3.77E+00
Benzene			9.03E-01	3.96E+00
bis(2-Ethylhexyl)phthalate			1.01E-05	4.43E-05
Bromomethane			3.23E-03	1.41E-02
Carbon tetrachloride			9.68E-03	4.24E-02
Chlorobenzene			7.10E-03	3.11E-02
Chloroform			6.02E-03	2.64E-02
Chloromethane			4.95E-03	2.17E-02
1,2-Dichloroethane			6.24E-03	2.73E-02
Dichloromethane			6.24E-02	2.73E-01
1,2-Dichloropropane			7.10E-03	3.11E-02
2,4-Dinitrophenol			3.87E-05	1.70E-04
Ethylbenzene			6.67E-03	2.92E-02
Formaldehyde			9.46E-01	4.14E+00
Naphthalene			2.09E-02	9.13E-02
4-Nitrophenol			2.37E-05	1.04E-04

Pentachlorophenol			1.10E-05	4.80E-05
Phenol			1.10E-02	4.80E-02
Propionaldehyde			1.31E-02	5.74E-02
Styrene			4.09E-01	1.79E+00
Tetrachlorethane			8.17E-03	3.58E-02
Toluene			1.98E-01	8.66E-01
Trichloroethylene			6.45E-03	2.83E-02
2,4,6-Trichlorophenol			4.73E-06	2.07E-05
Vinyl Chloride			3.87E-03	1.70E-02
o-Xylene			5.38E-03	2.35E-02
Antimony			1.70E-05	7.44E-07
Arsenic			4.73E-05	2.07E-06
Cadmium			8.82E-06	3.86E-07
Chromium			4.52E-05	1.98E-06
Chromium (VI)			7.53E-06	3.30E-07
Manganese			3.44E-03	1.51E-04
Nickel			7.10E-05	3.11E-06
Phosphorus			5.81E-05	2.54E-06
Selenium			6.02E-06	2.64E-07
Acenaphthene			1.96E-04	8.57E-04
Acenaphthylene			1.08E-03	4.71E-03
Anthracene			6.45E-04	2.83E-03
Benzo(a)anthracene			1.40E-05	6.12E-05
Benzo(a)pyrene			5.59E-04	2.45E-03
Benzo(b)fluoranthene			2.15E-05	9.42E-05
Benzo(e)pyrene			5.59E-07	2.45E-06
Benzo(g,h,i)perylene			2.00E-05	8.76E-06
Benzo(j,k)fluoranthene			3.44E-05	1.51E-04
Benzo(k)fluoranthene			7.74E-06	3.39E-05
Chrysene			8.17E-06	3.58E-05
Dibenzo(a,h)anthracene			1.96E-06	8.57E-06
Fluoranthene			3.44E-04	1.51E-03
Fluorene			7.31E-04	3.20E-03
Indeno(1,2,3-cd)pyrene			1.87E-05	8.19E-05
2-Methlnaphthalene			3.44E-05	1.51E-04
Naphthalene			2.09E-02	9.13E-02
Perylene			1.12E-07	4.90E-07
Phenanthrene			1.51E-03	6.59E-30
Pyrene			7.96E-04	3.48E-03
Monochlorobiphenyl			4.73E-08	2.07E-07
Dichlorobiphenyl			1.59E-07	6.97E-07
Trichlorobiphenyl			5.59E-07	2.45E-06
Tetrachlorobiphenyl			5.38E-07	2.35E-06
Pentachlorobiphenyl			2.58E-07	1.13E-06
Hexachlorobiphenyl			1.18E-07	5.18E-07
Heptachlorobiphenyl			1.42E-08	6.22E-08
Decachlorobiphenyl			5.81E-08	2.54E-07
Tetrachlorodibenzo-p-dioxins			6.36E-08	2.78E-07
Pentachlorodibenzo-p-dioxins			7.73E-08	3.38E-07
Hexachlorodibenzo-p-dioxins			7.00E-08	3.06E-07
Heptachlorodibenzo-p-dioxins			1.15E-07	5.02E-07
Octachlorodibenzo-p-dioxins			2.35E-07	1.03E-06
Tetrachlorodibenzo-p-furans			1.77E-07	7.74E-07
Pentachlorodibenzo-p-furans			3.81E-07	1.67E-06
Hexachlorodibenzo-p-furans			2.90E-07	1.27E-06
Heptachlorodibenzo-p-furans			1.56E-07	6.81E-07
Octachlorodibenzo-p-furans			6.21E-08	2.72E-07

Greenhouse Gas (GHG) Emissions:

On June 3, 2010, EPA issued the Tailoring Rule and established two steps to implement PSD and Title V,

- Tailoring Rule Step 1 began on January 2, 2011. Step 1 applies to sources subject to

PSD or Title V anyway due to their emissions of other pollutants ("anyway" sources) and that have the potential to emit 75,000 tpy CO_2e (or increase emissions by that amount for modifications);

- Tailoring Rule Step 2 began on July 1, 2011. In addition to anyway sources, Step 2 applies to new facilities emitting GHGs in excess of 100,000 tpy CO_2e and facilities making changes that would increase GHG emissions by at least 75,000 tpy CO_2e, and that also exceed 100/250 tpy of GHGs on a mass basis.

On July 20, 2011, EPA had deferred for a period of three years the application of PSD and Title V permitting requirements to CO_2 emissions from bioenergy and other biogenic stationary sources (biogenic CO_2).

The applicant did not address GHGs in this application since excluding CO_2 effectively eliminates the possibility of reaching the 75,000 tpy CO_2e PSD trigger.

Ambient Air Quality Impact Assessment (AAQIA):

An ambient air quality impact analysis (AAQIA) was performed as part of the initial covered source permit application to show compliance with the ambient air quality standards. The changes in proposed emission rates associated with biomass combustion have been evaluated using current EPA modeling practices as described below.

<u>Project Overview</u>
The project addressed by this air dispersion modeling analysis is a significant modification to a covered source permit to authorize biomass firing at the AES Hawaii, Inc. site. The application proposes to authorize an increase in permitted emissions of HAPs and dioxins. A health effects review and associated air dispersion modeling was performed by the applicant to demonstrate compliance with Hawaii Administrative Rules (HAR) §11-60.1-179.

<u>Air Quality Monitoring Data</u>
Background concentrations were not required for this health effects analysis. Therefore, monitoring data is not applicable.

<u>Modeling Emissions Inventory</u>
All HAPs and dioxins with a proposed permitted emissions increase are included in the health effects review. The only emission sources affected by this application are the two circulating fluidized bed (CFB) steam boilers.

<u>Stack Parameter Justification</u>
Modeling was conducted using the following scenarios:

- 8-hr concentrations assuming the boilers are operating at full load conditions (full proposed emission rate and full stack velocity),
- 8-hr concentrations assuming the boilers are operating at reduced load conditions (50% of proposed emission rate and 50% of full stack velocity),
- Annual concentrations assuming the boiler is operating at full load conditions year round, and
- Annual concentrations assuming the boiler is operating at reduced load conditions year round.

The two boilers release their emissions through a single stack (Emission Point/Model ID No. 1). The stack was modeled as a point source using the actual stack release height (86.9 m) and actual stack diameter (3.66 m). The stack was modeled with an exhaust temperature of 402.6 K, an exhaust velocity of 35 m/s for the full load case, and an exhaust velocity of 17.5 m/s for the reduced load case.

Scaling Factors

- Because the health effects analysis includes a large number of HAPs and dioxins, a scaling approach was used. The scaling approach is discussed below.

Models Proposed

Refined modeling was performed using EPA's AERMOD Model Version 09292. The regulatory default options were used.

Selection of Dispersion Option

The selection of either urban or rural dispersion coefficients for this modeling analysis is based on the land use method. The land use procedure involves classifying the land use within a 3000-m radius about the source by using the meteorological land use typing scheme. If the land use Types I1, I2, C1, R2, and R3 account for 50% or more of the total land area, urban dispersion coefficients should be used; otherwise, rural dispersion should be used.

The estimated land use is documented in Attachment A and is based on the USGS 7.5-minute series Ewa, HI quadrangle. The land use within a 3000-m radius of the stack is primarily water surface (classification A5, rural), with the remainder being undeveloped or industrial land. Since the percent urban area is less than 50%, the rural dispersion coefficient was used in this modeling analysis.

Building Wake Effects (Downwash)

The building downwash parameters input into the AERMOD model were prepared using the BPIP building downwash model (dated 04274). The "P" flag was set for preparing downwash related data for a model run utilizing the AERMOD program. The locations of all buildings and structures are provided on the plot plan.

Receptor Grid – Terrain

Receptor elevations were considered. Receptor elevations were extracted from a national elevation dataset (NED) file (NAD 1983 datum). The NED file was obtained from the USGS National Map Seamless Server. AERMAP generated error messages when it did not have NED data to assign to specific receptor coordinates. These errors occurred over the ocean; therefore, the missing elevations were assigned a value of 0 meters.

Receptor Grid – Design

Receptor grids are based on UTM coordinates (NAD 1983). Receptors were placed on the property line every 25 meters. A 25 meter receptor spacing was used out to 100 meters from the property line. A 100 meter receptor spacing was used out to 1000 meters from the property line. A 50 meter receptor spacing was used out to 10000 meters from the property line. A fine receptor grid (25 m) was then used to zone in on the areas where maximum concentrations were predicted. The modeling results were checked to ensure that the maximum distance was sufficient to capture the maximum off-property concentration.

Meteorological Data

AERMET was used to process the most recent available 5 years of meteorological data (2006-2010). The closest surface data station to the site is the Kalaeloa Airport. However, this data set was not used because it was insufficiently complete. Surface data from the Honolulu International Airport was used instead. This data station is located at 21.328 N, 157.943 W, which is approximately 18 miles east of the AES, Hawaii plant site. The surface station base elevation is 4.6 m. Upper-air data from Lihue/Kauai was used. This data station is located at 21.98 N, 159.35 W.

Due to the absence of NLCD92 data for Hawaii, the EPA's AERSURFACE program cannot be used to obtain the surface characteristics for this data set. The state of Alaska's Department of Environmental Conservation Division produced a memo on April 23, 2008 with suggested calculation methods for determining these values as required by the AERMOD Implementation Guide. This method was used for this data set.

Modeling was conducted using the following scenarios:

- 8-hr concentrations assuming the boilers are operating at full load conditions (full proposed emission rate and full stack velocity),
- 8-hr concentrations assuming the boilers are operating at reduced load conditions (50% of proposed emission rate and 50% of full stack velocity),
- Annual concentrations assuming the boiler is operating at full load conditions year-round, and
- Annual concentrations assuming the boiler is operating at reduced load conditions year-round.

The highest concentration occurred within the 500 m receptor grid. Therefore, the model was also run using a fine receptor spacing (25 m) in that area to ensure the maximum concentration was determined. The tables below summarize the modeling results for the scaling emission rates of 1 g/s (full load) and 0.5 g/s (reduced load).

Scaling Modeling Results – Full Receptor Grid

Model ID	Scenario	Year	Maximum Impact 8-hr Average ($\mu g/m^3$)	Maximum Impact Annual Average ($\mu g/m^3$)
1	Full Load	2006	1.68329	0.06705
		2007	0.83142	0.07610
		2008	0.68768	0.06536
		2009	1.48845	0.06909
		2010	0.73042	0.07370
	Full Load Case Maximum Impact		1.68329	0.07610
1B	Reduced Load	2006	1.18798	0.07423
		2007	0.58286	0.08304
		2008	0.44075	0.07099
		2009	0.72937	0.07532
		2010	0.51689	0.07935
	Reduced Load Case Maximum Impact		1.18798	0.08304
	Maximum Impact		1.68329	0.07610*

* Worst case impacts occur when the Full Load Case maximum impact is multiplied by the full proposed annual allowable. The impact from the Reduced Load Case multiplied by half the proposed annual allowable will be less than the Full Load Case value.

Scaling Modeling Results – Fine Receptor Grid

Model ID	Scenario	Year	Maximum Impact 8-hr Average (μg/m^3)	Maximum Impact Annual Average (μg/m^3)
1	Full Load	2006	1.68882	0.06704
		2007	0.83325	0.07623
		2008	0.70288	0.06543
		2009	1.54157	0.06932
		2010	0.73064	0.07372
	Full Load Case Maximum Impact		1.68882	0.07623
1B	Reduced Load	2006	1.25367	0.07422
		2007	0.61915	0.08309
		2008	0.46668	0.07107
		2009	0.73156	0.07578
		2010	0.53848	0.07934
	Reduced Load Case Maximum Impact		1.25367	0.07934
	Maximum Impact		1.68882	0.07623*

* Worst case impacts occur when the Full Load Case maximum impact is multiplied by the full proposed annual allowable. The impact from the Reduced Load Case multiplied by half the proposed annual allowable will be less than the Full Load Case value.

For both the 8-hr and annual averaging times, the full load scenario produced the maximum off-property impacts. Therefore, the full load scenario was used to demonstrate compliance. The resulting maximum off-property impacts were then scaled by the proposed emission rate for each HAP and dioxin species.

The scaled maximum off-property impacts for each VOC or trace metal species were compared to the following thresholds:

- For all species, the maximum 8-hr off-property concentration was compared to 1/100 of the TLV-TWA, per HAR §11-60.1-179(c)(1),
- For non-carcinogens, the maximum annual off-property concentration was compared to 1/420 of the TLV-TWA, per HAR §11-60.1-179(c)(1), and
- For carcinogens, the maximum annual off-property concentration was compared to the EPA Region 9 Regional Screening Level (June 2011) to determine if the concentration may result in an excess individual lifetime cancer risk of more than ten in one million assuming continuous exposure for seventy years, per HAR §11-60.1-179(c)(3).

The modeling and calculations indicate that all HAP concentrations will be below the significant ambient air concentration levels. No exceedances of the allowable maximum 8-hr or annual off-property concentrations are predicted. Therefore, the proposed project is predicted to have an acceptable impact on public health.

Significant Permit Conditions:

Significant permit conditions included the following:

- Added 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units, as an applicable Federal Regulation in Attachment IIA, Section B – Applicable Federal Regulations.
- Added wood fuel burning conditions in Attachment IIA, Section C – Operational and Emission Limitations as follows:

2. Wood Fuel

   a. The boilers may also be fired on a mixture of coal and wood fuel such that the combined feed rate does not exceed 233,000 lb/hr (116.5 tons/hr).
   b. The maximum amount of wood fuel fired into the boilers shall not exceed 20 tons/hr and 175,200 tons per any rolling twelve-month (12-month) period.
   c. The maximum heat input from wood fuel firing shall not exceed 215 MMBtu/hr and 1,883,400 MMBtu per any rolling twelve-month (12-month) period.
   d. All wood fuel, including wood processed into pellets which may utilize a *polyethylene binder*, fired by the boilers shall be untreated and uncontaminated by paint, glues, preservatives, oils, added chemicals, or similar foreign substances. Use of construction demolition debris of any type as wood fuel is explicitly prohibited.
   e. Wood fuel shall consist of chips or pellets of uncontaminated whole tree wood, including stumps, branches, bark, chips, and sawdust.

- Added coal, TDF and wood fuel burning conditions in Attachment IIA, Section C – Operational and Emission Limitations as follows:
  3. Tire Derived Fuel (TDF)
     b. The boilers may also be fired on a mixture of coal, TDF, and wood such that the combined feed rate does not exceed 233,000 lb/hr (116.5 tons/hr).
- Added HCl emission limits of 4.30 lb/hr and 0.002 lb/MMBtu in the Maximum Emission Limits table in Attachment IIA, Section C – Operational and Emission Limitations, Special Condition No. C.10.
- Added wood fuel monitoring and recordkeeping requirements in Attachment IIA, Section D – Monitoring and Recordkeeping Requirements as follows:
  2. Wood Fuel

     a. Wood Feed Rate

        The permittee shall install, operate and maintain a non-resetting weigh scale for the continuous and permanent recording of the total amount of wood fuel fed to the boilers, in pounds. All wood fuel fed to the boilers shall be recorded by the weigh scale monitoring system.

        1) The following information shall be recorded on a daily basis:

           a) Date of the meter reading;
           b) Beginning meter reading for the day;
           c) Ending meter reading for the day; and
           d) Total amount of wood fed to the boilers, in pounds, for the day.

        2) The following information shall be recorded on a monthly basis:

           a) Total amount of wood fed to the boilers, in pounds, for each month; and

b) Total amount of wood fed to the boilers, in pounds, on a rolling twelve-month (12-month) basis.

3) The weigh scale shall be calibrated on a monthly basis or more frequently as recommended by the manufacturer. Each calibration of the weigh scale shall be recorded on the Inspection, Maintenance, and Repair Log of Attachment IIA, Special Condition No. D.4. Upon written request and justification, the Department of Health may approve a less frequent calibration schedule if it can be demonstrated that the weigh scale, due to minimum variations, need not be calibrated on a monthly basis. The calibration schedule for the weigh scale shall be no less frequent than on a monthly basis for the first year of operation or as recommended by the manufacturer.

4) The installation of any new non-resetting meters or the replacement of any existing non-resetting meters shall be designed to accommodate a minimum of five (5) years of equipment operation, considering any operational limitations, before the meter returns to a zero reading.

b. Wood Heat Input

Total wood heat input to the boilers shall be recorded on a monthly and rolling twelve-month (12-month) basis. The total monthly wood heat input to the boiler shall be determined by multiplying the total pounds of wood fed to the boiler for each month from Attachment IIA, Special Condition No. D.2.a.2)a) by the wood's higher heating value of Attachment IIA, Special Condition No. D.2.c.1) for the month.

c. Wood Sampling and Analysis

1) On a **monthly basis**, the wood shall be sampled and analyzed in accordance with the wood sampling protocol of Attachment IIA, Special Condition No. E.6.a., to determine the higher heating value of the fuel. Samples shall be collected for analysis at least once per calendar month. Samples shall be collected at least **twenty (20) days** from the last sample collected or less as approved by the Department of Health.

2) On a **quarterly basis**, the wood shall be sampled and analyzed in accordance with the wood sampling protocol of Attachment IIA, Special Condition No. E.6.a., to determine the proximate and ultimate analysis, and the chlorine content of the fuel. Samples shall be collected for analysis at least once per calendar quarter. Samples shall be collected at least **sixty (60) days** from the last sample collected or less as approved by the Department of Health. Upon written request and justification, the Department of Health may approve a less frequent sampling and analysis schedule if it can be demonstrated that there are minimum

variations in the wood fuel characteristics. The sampling and analysis schedule shall be no less frequent than on a quarterly basis for the first year of operations.

d. Vendors or Sources of Wood Fuel

Records shall be maintained on vendors or sources furnishing wood fuel for use in the boilers. Records shall include:

1) Date that wood fuel for the boilers is delivered to the facility;
2) Name of the vendor or source;
3) Description of the wood fuel accepted for use in the boilers (the description shall include tree species and tree section such as bark, leaves, branches, trunk, etc.); and
4) Amount of wood fuel (pounds or tons).

- Added wood sampling and analysis requirements in Attachment IIA, Section E – Notification and Reporting Requirements as follows:

6. Wood Sampling and Analysis

a. Protocol

At least **sixty (60) days** prior to commencement of biomass (wood) combustion in the boilers, the permittee shall submit to the Department of Health for approval, in writing, a wood sampling and analysis protocol for determining the wood's proximate and ultimate analysis, the chlorine content, and higher heating value of the fuel. The protocol shall address in detail the sampling and testing methodology to ensure the samples collected are representative of the wood fired in the boilers during the sampling period. The protocol shall also identify the requirement that the collection of each sample include a recorded description of the wood samples collected (such as the tree species and tree section such as bark, leaves, branches, trunk, etc.). The permittee shall obtain approval for the sampling protocol prior to the commencement of biomass (wood) combustion in the boilers.

Manufacturer's literature on the weigh scale required by Attachment IIA, Special Condition No. D.2.a. shall be submitted to the Department of Health along with the wood sampling and analysis protocol. The literature should include information on the accuracy, manufacturer's recommended calibration methods and frequency, and operating details of the weigh scale.

b. Submittal of Wood Sampling and Analysis Results

Results of the wood sampling and analysis shall be submitted to the Department of Health **within sixty (60) days after** *the end of each semi-annual calendar period* (January 1 to June 30 and July 1 to December 31). The results shall include the sampling collection date, analyzed date, the proximate and ultimate analysis, the chlorine content of the fuel, the higher heating value of the fuel, a description of the wood samples collected and certification that the wood samples were collected and analyzed according to the wood sampling protocol of Attachment IIA, Special Condition No. E.6.a.

- Added HCl testing requirements in Attachment IIA, Section F – Testing Requirements as follows:

2. HCl Emissions

a. Within **sixty (60) days** after achieving the maximum biomass (wood) firing rate in the boilers, but not later than **one hundred eighty (180) days** after commencement of biomass (wood) combustion in the boilers, and **annually** thereafter, the permittee shall conduct, or cause to be conducted, performance tests on the boilers to determine the emission rate of HCl for the purpose of determining compliance with the emission limit provided for under Attachment IIA, Special Condition No. C.10. The source test for HCl emissions shall be performed with the boilers firing the maximum allowable biomass rate in combination with the minimum anticipated coal feed rate that would be reasonably anticipated during biomass firing.

b. The following test methods (referenced in Appendix A of 40 CFR, Part 60) or U.S. EPA-approved equivalent methods with prior written approval from the Department of Health shall be used:

Methods 1-4 and 26 or 26A for the emissions of HCl.

c. The test report (as required by Attachment IIA, Special Condition No. F.8.) for the source performance tests for HCl shall include:

1) The operating conditions of the boilers at the time of the test;
2) The HCl emission rate in lb/MMBtu and lb/hr;
3) The proximate and ultimate analysis, the chlorine content of the fuel, the higher heating value of the fuel, and a description of the wood samples collected for each of the three (3) test runs. The collection of the wood sample and the analysis shall follow the wood sampling protocol of Attachment IIA, Special Condition No. E.6.a. to ensure the samples collected during the test are representative of the fuel fired in the boilers at the time of the test; and
4) The records or a summary of the records containing all of the information maintained in accordance with Attachment IIA, Special Condition No. D.2.d. from the start of boiler operations up until the date of the current performance test.

d. The permittee shall conduct a performance test as specified in Attachment IIA, Special Condition No. F.2.a. to F.2.c. within **ninety (90) days** from the implementation of operational or physical modifications that have the potential to increase emissions of HCl above that of the prior performance test.

Conclusion and Recommendations:

The proposed addition of biomass (wood) as an additional fuel for the steam boilers complies with all State and Federal rules, regulations and standards with regards to air pollution. Therefore, a Significant modification to Covered Source Permit (CSP) No. 0087-02-C for AES Hawaii, Inc. is recommended based on the information provided in the air permit application, the significant permit conditions above, and subject to a 30-day public review period and 45-day EPA review period.

Reviewer: Darin Lum
Date: 2/2012