COVERED SOURCE PERMIT REVIEW - NO. 0620-01-C

Initial Permit - 12 MM Gallon/Year Ethanol Plant

Application No. 0620-01

Applicant: Kauai Ethanol LLC.
Facility: 12-million gallon per year ethanol manufacturing plant
Equipment Location: TMK 1-7-06-1, Kaumakani, Kauai

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Proposed Project:

Kauai Ethanol LLC (KE) is proposing to build and operate a 12 million gallon per year ethanol manufacturing facility on Kauai. The fuel grade ethanol will be manufactured by processing molasses. The basic process involves fermenting, distilling, and dehydrating. Support processes include power and steam generation and ethanol storage and distribution. The facility is expected to operate 24 hours per day and 8,360 hours per year.

Process Description:

Manufacturing ethanol from molasses consists of 3 main processes - yeast propagation and fermentation, distillation, and dehydration.

Yeast Propagation and Fermentation

Soon after the initial start-up of the plant, yeast culture will be propagated in culture and activation vessels. The mature yeast is mixed with molasses in fermenters. During the reaction period, the mixture is circulated through coolers to remove reaction heat. Once the reaction period is complete, the fermented *'mash'* is sent to a yeast settling tank where the yeast is separated from the fermented mash. The separated yeast is a concentrated *'cream'* that is reactivated by adding air and molasses. Once reactivated, the yeast is sent back to the fermenters to start another fermented mash cycle. During the fermentation process, the gases are vented to a CO_2 scrubber. The gases include ethanol, CO_2, air and water. The CO_2 scrubber uses water to remove the entrained alcohol and then vents the scrubbed CO_2 to the atmosphere.

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The fermented mash from the settling tank is pumped to the distilling section where it is heated and pumped into a mash column. An evaporator in the column removes the vapors from the fermented mash. The remainder of the fermented mash is called *'vinasse'*. Some of the vinasse is recycled back into the fermentation process to reduce the quantity of dilution water required. The remaining portion is sent to an evaporator to be concentrated to approximately 60 percent solids and then disposed of as solid waste. Two 172,700 gallon fixed roof storage tanks will be used to store the vinasse.

Distillation

The vapors from the mash column are then fed to a rectifier column which condenses the vapors. The condensate from the rectifier is returned to the mash column as reflux. Both of the columns operate under a vacuum and do not have any emission points. Uncondensed gases are drawn through a ethanol scrubber. The counter-current sieve tray scrubber uses water to remove alcohol and water from the uncondensed distillation gases. The ethanol scrubber will exhaust CO_2, air, water, and ethanol to the atmosphere.

An intermediate product called *'fusel oils'* is drawn from the mash column and stored in a 3,000-gallon fixed roof storage tank. Fusel oils are higher order alcohols that are formed during the fermentation process and has a vapor pressure of 0.9 psi at 20º C. With the plant running at design capacity, KE expects to draw 50 gallons of fusel oil per day.

The hydrous ethanol vapor from the distillation columns are sent to a feed preheater and then fed to a vaporizer flash tank. The vapors are then drawn through a molecular sieve superheater. Heat to the superheater is provided by condensing steam. The heated vapor then passes through the molecular sieve dehydrator. Water vapor is adsorbed by the molecular sieve media and the ethanol that passes through is dehydrated. The dehydrated ethanol vapors are then drawn through two condensers. The heat from the condensing ethanol is used to heat process water. Before being stored in the day storage tanks, the ethanol is further cooled by sending it though a heat exchanger.

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Dehydration

The molecular sieve media needs to be regenerated once the adsorption limit of the media is reached. Regeneration of the media is done by drawing anhydrous ethanol vapor, the regenerant, through the sieve. This process desorbs the water from the media. The regenerant vapors are then sent through a condenser where the heat from the condensation heats process water. The regenerant vapors that do not condense in the condenser are discharged to the atmosphere. This exhaust stream will contain small amounts of ethanol.

Ethanol Storage and Transfer

The ethanol in the day tank is transferred to one of five 39,000 gallon fixed roof storage tanks. The ethanol is blended with a gasoline in the 39,000 gallon storage tanks and is stored as denatured ethanol. The denatured ethanol contains 5 percent gasoline by volume and, as such, the vapor pressure, 1.22 psia is only slightly higher than that of pure ethanol, 1.18 psia. The gasoline will be stored in a 5,000 gallon above-ground storage tank.

The ethanol will be loaded into gasoline tank trucks at a bottom-loading tank truck load rack. The tank truck load rack will have two load arms with each capable of loading 650 gallons per minute. KE however, will only use one arm at a time. A John Zink vapor combustion unit will be used to control the emissions from the tank truck load rack.

Steam and Electricity Generation

The facility will use a 50,000 lb/hr stoker-fired steam boiler to provide superheated process steam and electricity for the facility. High pressure steam will drive a steam turbine and the saturated steam exhaust will be used in the plant processes. The boiler will use an air heater which will use the exhaust gases to preheat the boiler feed water.

The primary fuel for the boiler will be Australian coal. The washed and processed coal will be stored on-site and conveyers will be used to move the coal to a coal day tank. In the event that coal is not available, fuel oil no. 2 will be used. Specification used oil and waste ethanol will also be burned in small quantities. The waste ethanol is actually contaminated gasoline product from the service stations. As such, the waste ethanol will be considered as spec used oil. The maximum heat input to the boiler is 70 MMBtu/hr continuous and 77 MMBtu/hr peak while firing on coal. When the boiler is firing on liquid fuels, the maximum heat input will be 56 MMBtu/hr. KE plans to operate the boiler for 8,360 hours per year.

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A diesel engine generator will provide back-up power to the facility when the boiler is not operating. A 2,083 bhp Caterpillar diesel engine will drive a 1.45 MW generator. The diesel engine will fire on fuel oil no. 2 and will operate for 266 hours per year.

Equipment Description:

The following equipment will be covered under this permit.

1. One (1) Praj Industries Carbon Dioxide Scrubber with six (6) sieve trays.
2. One (1) Praj Industries Ethanol Scrubber with eight (8) sieve trays.
3. One (1) 70 MMBtu/hr stoker-fired steam boiler, Alpha Boilers Inc., model Alpha ATT 25-27 MP, with lime injection system.
4. Air Pollution Control Equipment for the Boiler:
   a. Limestone injection system;
   b. Selective non-catalytic reduction (SNCR) with ammonia/urea injection system;
   c. One 2,500 gallon urea storage tank; and
   d. Baghouse
5. Bottom-loading petroleum tank truck loading rack with of two (2) 650 gpm loading arms.
6. John Zink Vapor Combustion Unit, model no. ZCT-1-4-20-X-1/4.
7. One (1) 1.45 MW Caterpillar Diesel Engine Generator set, model no. 3516B
8. One (1) 145 bhp Clark diesel engine fire pump, model no. JU4H-UF54.
9. One (1) Marley Sigma F Series cooling tower, model no. F1262, and its' associated appurtenances

Air Pollution Controls:

The 70 MMBtu/hr steam boiler will utilize the following post-combustion control devices.

SNCR with Urea Injection

NO_X emissions will be controlled with SNCR using urea injection. This process breaks down the NO_X into water and atmospheric nitrogen.

Limestone Injection

SO_2 emissions will be controlled with the injection of limestone into the combustion zone. The limestone absorbs the SO_2 and forms gypsum. The lighter particles of limestone and gypsum are carried by the flue gases

Baghouse

Particulate emissions will be controlled with a baghouse. The baghouse utilizes filter bags to capture the particulates from the combustion of coal and the lighter particles limestone/gypsum that are carried by the flue gases.

Vapor Combustion Unit

A John Zink vapor combustion unit (VCU) will be used to capture and burn the VOC vapors from the bottom-loading tank truck load rack. The VCU uses two pilot burners, firing on propane, to ignite the VOC vapors collected during tank truck loading operations. The system, which includes the vapor collection system, has a guaranteed VOC destruction efficiency of

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98 percent. John Zink also guarantees that the VCU will emit no more than 10 mg of CO per liter of fuel loaded and 4 mg of NO_X per liter of product loaded.

Applicable Requirements:

Hawaii Administrative Rules (HAR):

Chapter 11-59, Ambient Air Quality Standards
Chapter 11-60.1 Air Pollution Control
- Subchapter 1, General Requirements
- Subchapter 2, General Prohibitions
  - 11-60.1-31 Applicability
  - 11-60.1-32 Visible Emissions
  - 11-60.1-33 Fugitive Dust
  - 11-60.1-37 Process Industries
  - 11-60.1-38 Sulfur Oxides from Fuel Combustion
  - 11-60.1-41 Pumps and Compressors
- Subchapter 5, Covered Sources
- Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
  - 11-60.1-111 Definitions
  - 11-60.1-112 General Fee Provisions for Covered Sources
  - 11-60.1-113 Application Fees for Covered Sources
  - 11-60.1-114 Annual Fees for Covered Sources
  - 11-60.1-115 Basis of Annual Fees for Covered Sources
- Subchapter 8, Standards of Performance for Stationary Sources
  - 11-60.1-161 New Source Performance Standards

BACT:

A Best Available Control Technology (BACT) analysis is required for each new or modified emissions unit located within a stationary source that has a net emissions increase equal to or greater than the significant levels defined in HAR §11-60.1-1. As shown in Table 1 below, the steam boiler is subject to a BACT analysis for NO_X, SO_X, and PM_{10}. KE has proposed to use selective noncatalytic reduction (SNCR), lime injection, and a baghouse as BACT for NO_X, SO_X, and PM_{10} respectively.

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Table 1. Potential Emissions from the Steam Boiler Firing Coal

Pollutant	Emissions (TPY)	BACT Trigger (TPY)
NO_X	80	40
SO_X	83	40
CO	64	100
PM_{10}	15	15
VOC	13	40

The RBLC database does not contain any listing for a coal fired boiler with a heat input less than 100 MMBtu/hr. However, the proposed control technology has been deemed as BACT for larger boilers firing on coal and liquid fuels. KE proposed the following emission limits based on the control technology:

Table 2. Control Technologies and Control Efficiencies for NO_X, SO_X, and PM_{10} Firing Coal

Pollutant	Control Technology	BACT Emission Rate (lb/MMBtu)	AP-42 Emission Rate (lb/MMBtu)	Control Efficiency (%)
NO_X	SNCR	0.27	0.46	42%
SO_X	lime injection	0.28	0.80	65%
PM_{10}	Baghouse	0.051	0.56	91%

The control efficiencies of the proposed control technologies are on the lower end of typical control efficiencies listed in the AP-42, miscellaneous U.S. EPA documents, and literature from various manufacturers. However, since a BACT determination is based on the technology, the emission limits maybe lowered in the future based on performance tests and other reliable literature. As such, the control technologies listed in Table 2 above shall be deemed BACT for the respective pollutants while firing on coal. Special conditions of the permit will include provisions to allow the Department to revise the allowable emission limits for NO_X, SO_X, and PM_{10}.

KE proposed to use the same emission rates while firing on liquid fuels. However, the proposed emission rate for NO_X, 0.27 lb/MMBtu, is higher than the AP-42 emission rate, 0.15 lb/MMBtu. Further, the proposed SO_x emission rate, 0.28 lb/MMBtu, provides for a much lower control

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efficiency. Since SO_2 emissions are a direct function of the amount of sulfur in the fuel and the sulfur content per MMBtu is much lower for oil as compared to coal, the SO_2 emissions from the boiler should be much lower than the proposed emission limit. Also, since the proposed control technologies are post-combustion controls, the control efficiencies of the control devices should be relatively consistent regardless of the fuel fired. In addition, the Department has reviewed other BACT determinations and in all instances the maximum allowable emission rates are lower than what the permittee is proposing. The permittee has stated that the manufacturer will not provide a guarantee for emission rates below the proposed limits. As such, the Department will initially use the proposed coal emission limits for the boiler while firing liquid fuels. The Department will reevaluate the emission limits after the initial source performance test and has incorporated a condition to lower the allowable emission limits based on the test results.

NSPS:

40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry.

40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

Synthetic minor:

A synthetic minor is a facility that without limiting conditions, physical or operational, emits above the major triggering levels as defined by HAR 11-60.1-1 for either criteria pollutant(s) or hazardous air pollutant(s). Without operational limits on the diesel engine generator, the facility would be a major source for CO and NO_x. Thus, KE is a synthetic minor.

<u>Non-Applicable Requirements:</u>

CAM:

The purpose of Compliance Assurance Monitoring (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

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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 100% of the major source level; and (5) not otherwise be exempt from CAM. Since the facility is not a major source, CAM does not apply.

CERR (Consolidated Emission Reporting Rule):

40 CFR part 51, Subpart A – Emission Inventory Reporting Requirements, determines the annual emissions reporting frequency based on the actual emissions of each pollutant from any individual emission point within the facility that emits at or above the triggering levels. Since the trigger levels are at or above the major source levels and this facility is not a major source, the facility is not subject to annual emission reporting under CERR.

The Department does however, require facilities to report their annual emissions if the facility-wide emissions exceed the Department's trigger levels. The Department uses the data for in-house recordkeeping purposes. The ethanol manufacturing plant exceeds the Department's trigger levels and is required to submit annual emissions. Table 3 below summarizes the Department's trigger levels and illustrates the facility's applicability.

Table 3 Comparison of Emissions to CAB Trigger Levels

Pollutant	Steam Boiler (TPY)	CAB trigger (TPY)
NO_X	80	25
SO_X	83	25
CO	64	250
PM_{10}	15	25
VOC	13	25

NSPS:

40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. The storage tanks that contain VOLs with a vapor pressure greater than 3.5 but less than 15 kPa are exempt because the storage capacity of each tank is less than 40,000 gallons. None of the storage tanks with a storage capacity of at least 20,000 gallons store a VOL with a vapor pressure greater than 15 kPa.

40 CFR 60, Subpart XX - Standards of Performance for Bulk Gasoline Terminals. The tank

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truck load rack is not subject to Subpart XX because the facility is not considered a Bulk Gasoline Terminal.

40 CFR Part 60, Subpart III - Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes. The facility is not subject to Subpart III because ethanol and yeast are not listed as chemicals subject to Subpart III.

40 CFR Part 60, Subpart NNN - Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations. Ethanol is listed as one of the chemicals subject to Subpart NNN. However, as stated in the Federal Register volume 67 no. 7, published on January 10, 2002, the U.S. EPA exempts ethanol manufacturing by biological synthesis from Subpart NNN. Since the ethanol is produced by fermentation, a biological synthesis, the facility is not subject to Subpart NNN.

40 CFR Part 60, Subpart RRR, Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes. Ethanol is listed as one of the chemicals subject to Subpart RRR. However, as with Subpart NNN, the U.S. EPA exempts ethanol manufacturing by biological synthesis from Subpart RRR. Since the ethanol is produced by fermentation, a biological synthesis, the facility is not subject to Subpart RRR.

NESHAP/MACT:

40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines is not applicable to the diesel engines because the facility is not a major source of HAPs.

PSD:

PSD does not apply since this facility is not a major stationary source.

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Insignificant Activities:

The facility will have the following insignificant activities.

1. Five 39,000 gallon fixed roof ethanol storage tanks. These tanks are less than 40,000 gallons. HAR 11-60.1-82(f)(1).

2. One 5,000 gallon above ground gasoline storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

3. Two 172,700 gallon fixed roof vinasse storage tanks. The vapor pressure of the vinasse is less than 1.5 psia and the total emissions from storing vinasse will be less than 2 tons per year VOC. HAR 11-60.1-82(f)(7).

4. Two 172,700 gallon fixed roof molasses storage tanks. The vapor pressure of the molasses is less than 1.5 psia and the total emissions from storing molasses will be less than 2 tons per year VOC. HAR 11-60.1-82(f)(7).

5. One 10,000 gallon above-ground diesel fuel storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

6. One 5,000 gallon above-ground diesel fuel storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

7. One 5,000 gallon above-ground waste ethanol storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

8. One 5,000 gallon above-ground spec used oil storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

9. One 10,000 gallon above-ground spent lees storage tank. This tank is less than 40,000 gallons. HAR 11-60.1-82(f)(1).

10. Yeast propagator. The yeast propagator vents to the atmosphere, but the process and reaction only emits water and CO_2.

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Alternate Operating Scenarios:

The applicant listed firing the boiler on either coal, fuel oil, or a combination of the two. When the boiler is firing on coal, the maximum heat input will be 70 MMBtu/hr continuous and 77 MMBtu/hr peak for 3 hours in a 24-hour period. When the boiler is firing on fuel oil, the maximum heat input will be 55.3 MMBtu/hr.

KE may also burn spec used oil in the boiler. The spec used oil will be blended with the fuel oil. As such, the maximum heat input to the boiler while firing spec used oil will be same as firing fuel oil, 55.3 MMBtu/hr. The applicant self-imposed a consumption limit of 161,812 MMBtu/yr, or 1,181,110 gallons per year of spec used oil. All spec used oil must be received from approved sources.

The Department is allowing KE to temporarily replace the 1.45 MW Caterpillar diesel engine with a similar diesel engine should the Caterpillar diesel engine need repairs that would require the engine to be removed. The Department is also allowing KE to use alternate fuels and fuel additives provided prior written approval from the Department is obtained.

Project Emissions:

Steam Boiler - firing coal

Emissions from the steam boiler while firing on coal were estimated using the BACT emission limits and AP-42 section 1.1, revised 9/98. For NO_X, SO_X and PM_{10}, the emission limits from the BACT analysis were used to calculate the potential emissions. CO and VOC emissions were estimated using tables 1.1-3 and 1.1-19, respectively, of the AP-42. Heat input and fuel consumption were calculated by using the fuel feed rate, a HHV of 11,800 Btu/lb, and assuming the 70 MMBtu/hr boiler will operate at peak load, 77 MMBtu/hr, for 3 hours each day. The boiler will operate for 8,360 hours per year, or 1,045 hours at peak load and 7,315 hours at continuous load. With a continuous feed rate of 3 tons per hour and a peak feed rate of 3.3 tons per hour, the total coal consumption is 25,394 tons per year. The table 4 below summarizes the emissions from the steam boiler firing on coal.

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Table 4. Steam Boiler Emissions - Firing Coal

Pollutant	Emission Factor	Emissions g/s [3]	lb/hr [3]	TPY [4]
NO_X	0.27 lb/MMBtu	2.62	20.80	80.0
SO_X	0.28 lb/MMBtu	2.72	21.60	83.0
CO	5 lb/ton	2.08	16.50	63.5
PM_{10} [1]	0.051 lb/MMBtu	0.50	3.93	15.1
VOC [2]	1.0 lb/ton	0.42	3.30	12.7

1 - all particulates assumed to be PM_{10}
2 - as methane
3 - based on peak load, 77 MMBtu/hr
4 - based on 7,315 hours at continuous load and 1,045 hours at peak load

Steam Boiler - firing fuel oil and spec used oil

Emissions from the steam boiler while firing on fuel oil no. 2 and spec used oil were estimated using the BACT emission limits and AP-42 section 1.3, revised 9/98. The emission rates from the BACT analysis were used to calculate the emissions of NO_X, SO_X, and PM_{10}. VOC emissions were estimated using the emission factors listed in sections 1.3 and 1.11 of the AP-42. The emission rate for CO is from the manufacturer and is higher than the AP-42. Heat input was based upon the fuel feed rate and the HHV values of the various liquid fuels. The HHV value used for fuel oil and spec used oil was 137,000 Btu/gal. With a fuel feed rate of 404 gallons per hour, the maximum heat input into the boiler is 462,709 MMBtu per year. The table below summarizes the emissions from the steam boiler firing on liquid fuels.

Table 5. Steam Boiler Emissions - Firing Liquid Fuels

Pollutant	Emission Factor	Emissions g/s	lb/hr	TPY
NO_X [1]	0.27 lb/MMBtu	1.88	14.94	62.5
SO_X [1]	0.28 lb/MMBtu	1.95	15.50	64.8
CO	6.3 lb/1,000 gal	0.32	2.55	10.6
PM_{10} [1]	2 lb/1,000 gal	0.10	0.81	3.4
VOC [2]	1 lb/1,000 gal	0.01	0.40	
VOC [3]	0.252 lb/1,000 gal			0.74

1 - NO_X and SO_X emission factors are the emission limits from the BACT analysis.
2 - VOC emission factor is for used oil, table 1.11-3 of the AP-42, used for short-term emissions
3 - VOC emission factor from table 1.3-3 of the AP-42. Annual emissions based on 843,650 gallons of spec used oil and 2,533,790 gallons of fuel oil no. 2.

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Ammonia Emissions

KE proposed a ammonia slip rate of 20 ppmvd at 3 percent O_2 or 0.01 lb/MMBtu. For the boiler firing on coal, the ammonia emissions based on that slip rate would be 3 tons per year. The proposed slip rate is slightly higher than what is being reported for similar systems. The Department will impose an ammonia emission limit of 0.7 lb/hr and 20 ppmvd at 3 percent O_2 while firing coal at 70 MMBtu/hr, 0.8 lb/hr and 22 ppmvd at 3 percent O_2 while firing coal at 77 MMBtu/hr, and 0.6 lb/hr and 20 ppmvd at 3 percent while firing liquid fuels. Maximum ammonia emissions are based on firing coal for 7,315 hours at 70 MMBtu/hr and 1,045 hours at 77 MMBtu/hr.

NH_3 = {[0.7 lb/hr * 7,315 hours] + [0.8 lb/hr * 1,045 hr]} / 2,000 lb/ton
= 3.0 tons per year

Diesel Engine Generator

Except for SO_2, emissions from the diesel engine generator were estimated using the not to exceed emissions data from the manufacturer. SO_2 emissions were estimated assuming all of the sulfur in the vapor converts to SO_2. The molecular weight of sulfur is 32 lb/lb mole and for SO_2, the molecular weight is 64 lb/lb mole. As such, the emissions of SO_2 will be twice the sulfur content. SO_2 emission factor was calculated using the sulfur content of the fuel, the fuel consumption rate, and the fuel density. The diesel engine generator is subject to NSPS Subpart IIII and as required by Subpart IIII, the diesel engine will fire on diesel fuel no. 2 with a sulfur content not to exceed 0.05 percent by weight. The table below summarizes the emissions from the diesel engine generator operating for 266 hours per rolling 12-month period.

Table 6. Diesel Engine Generator Emissions

Pollutants	Emission Factor (lb/hr)	Emissions - 266 hours (TPY)
NO_X	26.50	3.52
CO	24.44	3.25
SO_2 [1]	0.72	0.10
PM_{10} [2]	0.71	0.09
VOC [3]	0.65	0.09

1 - emission factor = 0.05% sulfur * 2 * 7.1 (lb/gal) * 101.6 (gal/hr)
2- all particulate assumed to be PM_{10}
3 - all hydrocarbons, including non-methane hydrocarbons assumed to be VOC

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Ethanol Processes

Emissions from the production of ethanol were estimated using information provided by the process manufacturer, Praj Industries. Most of the processes involved in producing ethanol are closed systems. The sources of emissions from the ethanol production are from the CO_2 scrubber, the ethanol scrubber, and the molecular sieve regenerator.

The gases from the fermentation process are vented to the atmosphere through the CO_2 scrubber. The scrubber uses water to capture the ethanol and releases CO_2 and uncaptured ethanol to the atmosphere. Using the vapor feed rate to the scrubber, the concentration of ethanol in the vapor, and the efficiency of the scrubber, the emissions from the CO_2 scrubber are:

VOC (lb/hr) = vapor feed rate * ethanol concentration * [1 - efficiency]

where: vapor feed rate = 7,850 lb/hr
ethanol concentration = 1.19%
recovery efficiency = 95%

VOC (lb/hr) = 7,850 lb/hr * 0.0119 * 0.05 = 4.67 lb/hr

The ethanol plant will operate for 8,360 hours per year. So,

VOC (TPY) = 4.67 lb/hr * 8,360 hr/yr / 2,000 lb/ton = 19.5 tons per year

Uncondensed gases from the distillation process are vented to the atmosphere through the ethanol scrubber. The sieve tray scrubber is 99 percent efficient and water to scrub the ethanol from the vapor. Emissions from this scrubber were estimated using the same equation above where:

vapor feed rate = 645 lb/hr
ethanol concentration = 53.5%
recovery efficiency = 99%
VOC (lb/hr) = 645 lb/hr * 0.535 * 0.01 = 3.45 lb/hr
VOC (TPY) = 3.45 lb/hr * 8,360 hours / 2,000 lb/ton = 14.4 tons per year

In the dehydration process, ethanol vapors are used to regenerate the molecular sieve media. Ethanol vapor is drawn through the media and the ethanol vapor desorbs the water from the media. The water laden vapor is then condensed and the remaining vapor that does not condense is discharged to the atmosphere. The manufacturer estimates that no more than 2 kg/day of ethanol is emitted. Assuming 24 per day operation and 8,360 annual operating hours,

VOC (lb/hr) = 2 kg/day * 2.2 lb/kg / 24 hr/day = 0.18 lb/hr
VOC (TPY) = 0.18 lb/hr * 8,360 hrs / 2,000 lb/ton = 0.8 tons per year

Table 7. Ethanol Production Emissions

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Pollutant	Source			Total
	CO_2 Scrubber	Ethanol Scrubber	Molecular Sieve Regenerator	
VOC	19.5	14.4	0.8	34.7

Fixed Roof Storage Tanks

Emissions from storing the ethanol denatured with 5 percent gasoline by volume, were estimated using AP-42 section 7.1, revised 9/97. The calculations assume a reid vapor pressure of 3.4 psia and a true vapor pressure of 2.28 psia. VOC emissions from each of the 39,000 gallon storage tanks were estimated at 2 tons per year. The calculations are shown in the appendix.

Fugitives

Fugitive emissions from the pumps, valves, fittings, and other connections were estimated using U.S. EPA's "*Protocol for Equipment Leak Emission Estimates*", dated February 1995. Emission factors and calculations are shown in the appendix. Total VOC emissions from the valves, pumps, and fitting were estimated at 0.3 tons per year.

Tank Truck Load Rack and Vapor Combustion Unit

Loading losses at the load rack were estimated using equation 1 of AP-42 section 5.2, revised 1/95. Since KE will not use tank trucks dedicated to ethanol service, it was assumed that the previous cargo in the tank trucks was gasoline. As such the value for M in the equation below is for gasoline and not ethanol. The vapor collection system is guaranteed to be 90 percent efficient.

$L_L = 12.46\ (SPM/T)(1 - VCE)$

where:

L_L = loading loss (pounds per 1,000 gallons of ethanol loaded)

S = saturation factor = 1

P = true vapor pressure of the gasoline = 8.08

M = molecular weight of gasoline vapors = 66 lb/lb-mole

T = temperature of the liquid loaded = 537 ºR

VCE = vapor collection efficiency = 90%

$L_L = 12.46 * (1 * 8.08 * 66 / 537) * (1 - 0.9) = 1.24$ lb/1,000 gallons

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For an annual production rate of 12 millions gallons of ethanol plus the 5 percent gasoline by volume denaturant, the total loading loss per rolling 12 months will be:

12,600,000 gal / 1,000 gal * 1.24 lb/1,000 gal * 1/2,000 ton/lb = 7.8 VOC

Emissions from the combustion of vapors in the vapor combustion unit (VCU) were estimated using the performance specifications from John Zink, the vapor combustion unit manufacturer. John Zink guarantees the VCU will destroy 98 percent of the VOC vapors. Of all the vapors generated during the loading operation, 90 percent is captured and sent to the VRU by the vapor collection system. Since the VCU is 98 percent efficient in destroying the VOC vapors, 2 percent is emitted, or

VOC emitted = (1 - 0.98) * total vapor

total vapor = 12.46 (SPM/T) * VCE * throughput in gallons / 1,000 gal

= 12.46 * (1 * 8.08 * 66 / 537) * (0.90) * 12,600

= 140,318 lbs

VOC emitted = (1 - 0.98) * 140,318 lbs

= 2,806 lbs.

The NO_X and CO emissions from the combustion of vapors in the VCU were estimated using the emission factors from John Zink. John Zink VCU is guaranteed to emit no more than 4 mg/liter of product loaded for NO_X and 10 mg/liter of product loaded for CO. Since the VCU only receives 90 percent of the vapor generated during the loading operations, the NO_X and CO emissions will be estimated using 90 percent of the product throughput, or

NO_X = 4 mg/l * 12,600,000 gallons * 3.7854 liters/gallon * 2.2046 e-6 lbs/mg * 0.90

= 379 lbs

CO = 10 mg/l * 12,600,000 gallons * 3.7854 liters/gallon * 2.2046 e-6 lbs/mg * 0.90

= 946 lbs

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SO_2 emissions were estimated assuming all of the sulfur in the vapor coverts to SO_2. The molecular weight of sulfur is 32 lb/lb mole and for SO_2, the molecular weight is 64 lb/lb mole. As such, the emissions of SO_2 will be twice the sulfur content. This is conservative as in reality, not all sulfur converts to SO_2 and further, sulfur does not readily vaporize at standard temperature and pressure. Using the typical sulfur content of 0.04 percent by weight for gasoline,

SO_2 = 0.04% * 2 * total vapor
= 0.04% * 2 * 140,318 lbs
= 112 lbs

Particulate emissions from the combustion of the vapors are considered negligible based on the design of the VCU and AP-42 section 13.5, Industrial Flares, revised 9/91. The VCU utilizes a blower to inject combustion air into the combustion unit. The injection of air also enhances air fuel mixing which promotes complete combustion and reduces smoke and particulate emissions. Per AP-42 section 13.5, the emission factor for a nonsmoking flare is 0.

Emissions from the 5.2 MMBtu/hr gas assist burner of the VCU were estimated using AP-42 section 1.5, LPG Combustion, revised 10/96. Emission factors were expressed in lb/10^3 gallons, so the fuel consumption rate was calculated using a HHV for propane of 90,5000 btu/gal. At 5.2 MMBtu/hr, the propane feed rate is 57.5 gallons per hour.

Table 8. Emissions from the 5.2 MMBtu/hr Burner

Pollutant	**Emission Factor (lb/10^3 gal)**	**Emissions (lbs)**	
		3,000 hrs	**8,760 hrs**
PM	0.4	69	202
SO_2	1.5	259	756
NO_2	14	2,415	7,052
CO	1.9	328	957
VOC[1]	0.2	35	101

1 - TOC as VOC

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The table below represents the total emissions from the operations at the tank truck load rack.

Table 9. Emissions from Tank Truck Loading Operations

Pollutant	Point Emissions (TPY)			Area Source (TPY)
	Vapor Combustion	VCU Burner (3,000 hrs)	Total	Fugitives from Collection System
PM_{10} [1]	negligible	0.03	0.03	n/a
SO_2	0.06	0.13	0.19	n/a
NO_2	0.19	1.21	1.40	n/a
CO	0.47	0.16	0.63	n/a
VOC [2]	1.40	negligible	1.40	7.8

1 - includes PM
2 - includes TOC

<u>Cooling Tower</u>

Emissions from the cooling tower were estimated using the total dissolved solids (TDS) concentration of the cooling water, the drift rate of the mist eliminator, and the feed rate of the cooling water. Multiplying the TDS, or the amount of solids in the cooling water, by the drift rate, which is the percent of cooling water that passes through the mist eliminator, will estimate how much solids are exhausted to the atmosphere by the cooling fan. It is assumed that the water in the drift evaporates and the remaining solids are PM_{10}.

PM_{10} = TDS (mg/l) * drift (%) * recirculation rate (gpm) * 8.345e-6 (lb-l/mg-gal) * 60 (min/hr)
= 5,000 * 0.00005 * 7,640 * 8.345e-6 * 60
= 0.96 lb/hr

For operating hours of 8,360 hours per year,

PM_{10} = 0.96 * 8,360 / 2,000 (lb/ton)
= 4.0 tons per year

<u>Diesel Engine Fire Pump</u>

Emissions from the diesel engine fire pump were estimated using the emission factors from the manufacturer. The 145 hp diesel engine is manufactured by John Deere and could be considered an insignificant activity as it will be operated only during testing, maintenance, and emergency conditions. However, the diesel engine is subject to NSPS Subpart IIII and will be included in the operating permit. As required by Subpart IIII, the diesel engine will fire on diesel fuel no. 2

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with a sulfur content not to exceed 0.05 percent by weight. The diesel engine is limited by Subpart IIII to operating 100 hours per year for maintenance and readiness testing. The table below shows the emissions from operating the diesel engine for 100 hours per rolling 12-month period.

Table 10. Emissions from the Diesel Engine Fire Pump

Pollutant	Emission Rate (g/hp-hr)	Emission Rate (lb/hr^3)	Emissions - 100 hrs (TPY)
NO_X	4.70	1.50	0.08
CO	1.98	0.63	0.03
SO_2	0.12	0.04	0.00
PM_{10} [1]	0.38	0.12	0.01
VOC [2]	0.27	0.09	0.00

1 - all particulate assumed to be PM_{10}
2 - all hydrocarbons, including non-methane hydrocarbons assumed to be VOC
3 - lb/hr = g/hp-hr * 2.2046e-3 (lb/g) * 145 (hp)

Facility Total

The table below summarizes the total emissions from the ethanol manufacturing facility.

Table 11. Total Emissions of the Facility

Emission Source	Emissions (TPY)				
	NO_X	SO_X	PM/PM_{10}	CO	VOC
CO_2 Scrubber	n/a	n/a	n/a	n/a	19.5
Ethanol Scrubber	n/a	n/a	n/a	n/a	14.4
Molecular Sieve Regeneration	n/a	n/a	n/a	n/a	0.8
Fugitive VOC	n/a	n/a	n/a	n/a	0.3
Storage Tanks	n/a	n/a	n/a	n/a	10.4
Load Rack	n/a	n/a	n/a	n/a	7.8
Cooling Tower	n/a	n/a	4.0	n/a	n/a
VCU	1.4	0.2	0.1	0.6	1.4
Steam Boiler firing coal	80.0	83.0	15.1	63.5	12.7
Diesel Engine Generator	3.5	0.1	0.1	3.3	0.1
Diesel Engine Fire Pump	0.1	0.1	0.1	0.1	0.1
Total	**85**	**83**	**19**	**68**	**68**

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Air Quality Assessment:

KE conducted an ambient air quality analysis with the Lakes Environmental software package using ISCST3, a U.S. EPA approved model, to determine source compliance with federal and state ambient air quality standards (AAQS). The maximum model-predicted concentrations were calculated to determine the maximum ambient air impacts. The model, methodology and assumptions used by KE in the ambient air quality analysis were determined to be consistent with state and federal guidelines as discussed below.

ISCST3 was run with the regulatory default option selected. The default options include the use of rural dispersion coefficients, stack tip downwash, default wind speed profile exponents, upper bound concentrations for downwash, and the calm processing routine.

The meteorological data used by KE for the analysis was collected by Kauai Island Utility Cooperative in 1991. The data was collected at Burns Field, approximately two miles from the project site. The upper air data set from Lihue airport was used with the Burns field data set in the model.

Wake effects from downwash were considered in the model. Wake effects are treated in the ISCST3 model by including direction specific building dimensions and locations for each emission source. The dimensions and locations were analyzed using the Lakes Environmental software which processes the data using the EPA Building Profile Input Program (BPIP). The BPIP program determines the dominant structure for each 10-degree increment. The dominant structure could be a building or a combination of buildings.

In the initial screening analysis, receptors were placed in a 25-meter spacing grid at the fence line and in a 180-meter grid elsewhere to locate the areas of high concentrations. Refined modeling used receptors spaced at 30-meter increments in areas of high concentrations predicted in the initial coarse grid modeling. Terrain features and ground level elevations were taken from the applicable U.S.G.S. DEM data and 7.5 minute topographic maps.

The tables below shows the input values for the parameters used in the model. The higher emission rates for the short-term averaging periods for the boiler reflect the three-hour peak load per day of 77 MMBtu/hr. The difference in the short-term emissions for the diesel engine reflect the throughput limit of 194,245 gallons in any rolling 12-month period. Emission of SO_2 and PM_{10} were deemed negligible for the vapor combustion unit. Annual emission of PM_{10} from the cooling tower were corrected to reflect annual operating hours of 8,360 hours per year.

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Table 12. Source Parameters

Source	UTM Coordinate (m)		Base Elevation (m)	Stack Height (m)	Stack Diameter (m)	Exit Temp (°K)	Exit Vel. (m/s)
	East	North					
Boiler	434,991	2,423,720	24.38	30.48	0.61	505.8	41.38
DEG	435,115	2,423,781	24.38	10.67	0.46	801.3	33.37
VCU	435,126	2,423,782	24.38	6.10	1.22	533.0	40.55
Cooling Tower Cell 1	435,132	2,423,765	24.38	7.62	5.49	304.4	9.22
Cooling Tower Cell 2	435,139	2,423,771	24.38	7.62	5.49	304.4	9.22

Table 13. Emission Rates for the Sources

Source	Pollutant/ Averaging Period	Emission Rate (g/s)
Boiler	NO_2 / annual	2.27
	SO_2 / 3-hr	2.72
	SO_2 / 24-hr	2.5
	SO_2 / annual	2.36
	CO / 1-hr	2.08
	CO / 8-hr	1.96
	PM_{10} / 24-hr	0.46
	PM_{10} / annual	0.43
DEG	NO_2	0.10
	SO_2 / 3-hr, 24-hr	0.73
	SO_2 / annual	0.02
	CO	3.08
	PM_{10} / 24-hr	0.09
	PM_{10} / annual	0.003
VCU	NO_2	0.006
	CO	0.41
Cooling Tower, each cell	PM_{10} / 24-hr	0.06
	PM_{10} / annual	0.057

The predicted concentrations are shown in the table below. Concentration levels are for the

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annual operations of 8,360 hours per year. Ozone Limiting Method was used to estimate NO_2 concentrations. Based on these assumptions, the facility should comply with state and federal ambient air quality standards for SO_2, NO_2, CO, and PM_{10}.

Table 14. Maximum Projected Impacts

Pollutant/ Averaging Time	Concentrations (µg/m^3)				Percent of Standard
	Facility	Background	Total	State Standard	
NO_2 / annual	1.7	9	10.7	70	15%
SO_2 / 3hr	711	10	721	1,300	55%
SO_2 / 24- hr	283	4	287	365	79%
SO_2 / annual	1.0	0.3	1.3	80	2%
CO / 1-hr	3,591	2,394	5,985	10,000	60%
CO / 8-hr	1,880	983	2,863	5,000	57%
PM_{10} / 24-hr	34.7	28	62.7	150	42%
PM_{10} / annual	3.6	16	19.6	50	39%

Although ammonia is not a criteria pollutant, there is a threshold limit value (TLV) set by the American Congress of Governmental Industrial Hygienists (ACGIH). The TLV is a concentration level which the ACGIH believes that workers may be repeatedly exposed to day after day without any adverse health effects. The TLV concentrations are time-weighted averages (TWA) for an eight hour day. The ACGIH TLV-TWA for ammonia is 25 ppm, or 17.7 mg/m^3.

Although not listed as a hazardous air pollutant (HAP), the Department at its' discretion will treat ammonia as a non-carcinogenic HAP and assess the emission concentration in accordance with §11-60.1-179(c) of the HAR. Under that portion of the HAR, emission concentrations of non-carcinogenic HAPs are compared to fractions of the TLV-TWA. Because the TLV-TWA is based on a healthy worker and not the general public, the Department requires the 8-hour average emission concentration of a HAP to be lower than 1/100 of the TLV-TWA and the annual average emission concentration to be lower than 1/420 of the TLV-TWA. In other words, the 8-hour ammonia concentration must be below 177 µg/m^3 and the annual average ammonia concentration must be below 42.2 µg/m^3.

KE modeled the ammonia concentrations for 1-hour and annual time averages. For the model inputs, the stack parameters remained the same. The emission rate used for the 1-hour time average was 0.257 g/s which reflects the boiler firing on coal at peak load, 77 MMBtu/hr, and the

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ammonia slip at 20 ppmvd at 3 percent O_2. The emission rate used for the annual concentration was 0.224 g/s which was calculated assuming 1,045 hours of peak operation (77 MMBtu/hr) and 7,315 hours of continuous operation (70 MMBtu/hr).

The predicted 1-hour maximum concentration was 7.68 $\mu g/m^3$. Using a scaling factor of 0.7 to convert the 1-hour average to an 8-hour average, the 8-hour average concentration for ammonia was 5.38 $\mu g/m^3$. The predicted 8-hour average for ammonia is much less than the 1/100 of the TLV-TWA.

$5.4\ \mu g/m^3 << 177\ \mu g/m^3$

The model predicted the maximum annual concentration for ammonia was 0.10 $\mu g/m^3$ and is much less than the 1/420 of the TLV-TWA.

$0.10\ \mu g/m^3 << 42.2\ \mu g/m^3$

The predicted 8-hour average and annual average ammonia concentrations are much less than the significant ambient air concentration specified in HAR §11-60.1-179. As such, it can be concluded that the ammonia emissions will not adversely impact the surrounding ambient air quality.

Other Issues:

Support Facility

The KE ethanol production plant will be located next to the Gay and Robinson (G&R) sugar mill on Kauai. There are ownership overlaps that between G&R and KE that can be construed as common ownership and control. As such, since molasses will be the feedstock for the ethanol production, the issue of the sugar mill being a support facility needs to be addressed.

As defined in 40 CFR §52.21(b)(5), a stationary source is defined as *any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act*. The terms building, structure, facility, or installation are defined in 40 CFR§52.21 (b) as *all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e. which have the same first two digit code) as described in the Standard Industrial Classification Manual . . ..* In essence, a support facility must be deemed a building, structure, facility, or installation as defined above and all of the pollutant-emitting activities must meet all of the following criteria:

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1. must belong to the same "Major Group" as defined in the Standard Industrial Classification Manual (SIC);
2. must be located on one or more contiguous or adjacent properties; and
3. must be under common control.

If any of the criteria are not met, then the facilities are considered separate stationary sources for regulatory purposes.

The SIC code is a system for classifying businesses by the type of economic activities its' engaged in. The classification of an emission unit or pollutant-emitting activity is based on the primary activity which an emissions unit is able to introduce a principle product into commerce or provide a service. G&R's principle activity is sugar refining, SIC 2062, and the principle product is sugar. KE's principle activity is the production of ethanol, SIC 2869, and the principle product is ethanol. Since the SIC codes are not of the same major group, G&R's sugar mill and KE's ethanol production plant should not be considered as one stationary source.

However, there are instances where sources from different major groups are considered as one source. In all instances the support facility contributed fifty percent or more of its' inputs or outputs to another source. One of the criterion that the U.S. EPA is proposing to use in its' definition of "Support Facility" is that a facility whose operation is integrally related to another facility's activities such that fifty percent of more of the facility's inputs or outputs are dedicated to activities at the other facility. Currently G&R produces 55,000 tons per year of sugar and 15,000 tons of molasses. Molasses is a by-product of the sugar refining process and represents 20 percent of the sugar mill sales. G&R currently ships the molasses to California where it is sold as cattle feed or ethanol feedstock. Although KE will purchase all of G&R's molasses, the 15,000 tons of molasses represents only 12 percent of KE's projected annual feedstock. Since KE needs to purchase more than 80 percent of the feedstock from outside sources, KE's ethanol production facility is not totally dependent upon G&R's sugar mill and further, the ethanol production facility could continue to operate if G&R's sugar mill shuts down. This non-dependency makes it difficult to classify G&R's sugar mill as a support facility. With this information, it is determined that G&R's sugar mill is not a support facility of KE's ethanol production facility.

<u>Emission Limits for the Steam Boiler</u>

The emission limits for the steam boiler while firing on coal were determined from the BACT analysis and AP-42 tables. KE used these emission limits in estimating the total emissions. When estimating the total emission from the steam boiler while firing liquid fuels, KE proposed to use the same BACT emission limit for NO_X and SO_X. As discussed in the BACT section

above, the Department will reluctantly accept these limits, but will revise the limits once the initial source performance test has been completed. In estimating the VOC emissions, KE used a much higher emission rate than that listed in the AP-42. In determining the emission limit for VOCs while firing on liquid fuels, the AP-42 emission factor for used oil was used. This emission rate is higher than the AP-42 emission rate for fuel oil no. 2, but is much lower than the emission rate used by KE in estimating emissions.

The proposed ammonia slip rate of 20 ppmvd at 3 percent O_2 is slightly high as compared to reported ammonia slip rates for similar systems. Typical ammonia slip rates for SCR/SNCR are below 5 ppmvd at 15 percent O_2. Excess ammonia slip is not desirable because the excess ammonia will react with other pollutants, such as sulfur, to form undesirable compounds, such as ammonium bisulfate. Ammonium bisulfate is a sticky, tar-like compound that accumulates on the ductwork and heat recovery surfaces down stream. In short, excessive ammonia slip increases operational and maintenance costs and at high slip rates, increases the opacity and exhaust plume density. With that, the Department will agree to the proposed maximum allowable ammonia emission rate.

Conclusion and Recommendation:

KE is proposing to build the first ethanol plant in the state on the island of Kauai. The production process and associated emission units will utilize add-on pollution control devices. The main emission unit is the steam generator which will provide process steam and electricity. The steam generator will be fired primarily upon coal and will use lime injection , SNCR, and a baghouse to control emissions. Emissions from the production and distribution of ethanol will be controlled by sieve tray scrubbers and a vapor combustion unit. Although emissions were based heavily upon manufacturer guarantees, the initial source performance tests should validate the manufacturers' guarantees. Additionally, as stated previously, the Department will reevaluate the maximum allowable emission rates after the initial source performance test and subsequent annual source performance tests.

Issuance of a Covered Source Permit is recommended based on the information provided by the applicant.

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Appendix

Emissions Calculations

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