Initial Covered Source Permit Review Summary

Significant Modification Application File No.: 0088-11

Permit No.: 0088-02-C

Applicant: Chevron USA Products Company

Facility Title: Chevron Hawaii Refinery
Located at 91-480 Malakole Street, Kapolei, Oahu

Mailing Address: Chevron USA Products Company
91-480 Malakole Street
Kapolei, HI 96707

Responsible Official: Mr. Thomas M. Kovar
Refinery Manager
(808) 682-5711

Point of Contact: Ms. Helen Mary Wessel
Environmental Specialists
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Application Date: May 25, 2006 and additional information dated August 23, 2006

Proposed Project:

SICC 2911 (Petroleum Refining)

Chevron submitted an application for a new Hybrid Energy Plant within the refinery site that will provide steam and electricity in support of refinery operations. The term "hybrid" is used because the proposed project includes two new steam boilers in addition to a new cogeneration turbine similar to the three cogeneration units already operating at the Hawaii Refinery. The steam and electrical power production of the new equipment will allow retirement of the three existing steam boilers within the refinery.

The cogeneration turbine will consist of a new Solar Centaur combustion turbine operating as a cogeneration plant to generate a power production capacity of approximately 3 MW. The combustion turbine will be equipped with water injection and low NO_x burners designed to limit emissions of NO_x. The thermal energy of the fuel combusted by the turbine is converted to mechanical energy, which drives an electrical generator. The hot exhaust gases from the turbine are routed to a heat recovery steam generator (HRSG), which is essentially a boiler for supplemental steam production. The HRSG will include a section for supplemental steam production using duct firing to increase steam pressure. Fuels for the combustion turbine will consist of a combination of refinery fuel gas (RFG) and liquid naphtha, although RFG will be provided to the HRSG duct burner.

The two new steam boilers will consist of Foster Wheeler steam boilers. The boilers will fueled by low sulfur fuel oil (LSFO) and RFG as determined by the fuel requirements and availability within the refinery. The boilers will each have a fuel energy input capacity of 99 MMBTU/hr and will generate additional steam to support processes throughout the refinery.

Equipment Description:

1. One (1) Cogeneration Unit consisting of the following:
   a. One (1) 46 MMBtu/hr combustion turbine, Solar Centaur 40, model no. 40-4071, serial no. 5157C.
   b. One (1) heat recovery steam generator (HRSG) with one (1) 49 MMBtu/hr duct burner, John Zink Company; and
   c. For NO_x control, the combustion turbine is equipped with water injection and low NO_x burners.

2. Two (2) 99 MMBtu/hr boilers, Foster Wheeler, model no. AG-5060, serial nos. 7414, National Board No. 585 and 7415, National Board No. 586.

3. Allowable Fuels
   a. Combustion turbine – Refinery Fuel Gas (RFG) and naphtha
   b. HRSG duct burner – RFG
   c. Boilers – Low Sulfur Fuel Oil (LSFO) and RFG

Applicable Requirements:

<u>Hawaii Administrative Rules (HAR)</u>

Title 11, Chapter 59 — Ambient Air Quality Standards

Title 11, Chapter 60.1 — Air Pollution Control

- Subchapter 1 — General Requirements
- Subchapter 2 — General Prohibition
  - HAR §11-60.1-31 — Applicability
  - HAR §11-60.1-32 — Visible Emissions
  - HAR §11-60.1-38 — Sulfur Oxides from Fuel Combustion
- Subchapter 5 — Covered Sources
- Subchapter 6 — Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
  - HAR §11-60.1-111 — Definitions
  - HAR §11-60.1-112 — General Fee Provisions for Covered Sources
  - HAR §11-60.1-113 — Application Fees for Covered Sources
  - HAR §11-60.1-114 — Annual Fees for Covered Sources
  - HAR §11-60.1-115 — Basis of Annual Fees for Covered Sources
- Subchapter 8 — Standards of Performance for Stationary Sources
- Subchapter 9 — Hazardous Air Pollutant Sources

Federal Requirements

40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)
- Subpart A – General Provisions
- Subpart J – Standards of Performance for Petroleum Refineries
- Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
- Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)
- Subpart A – General Provisions
- Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
- Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters
- Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

Non-Applicable Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 7	Prevention of Significant Deterioration Review

Federal Requirements
40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Best Available Control Technology (BACT):

A Best Available Control Technology (BACT) analysis is required for new covered sources or significant modifications to covered sources that have the potential to cause a net increase in air pollutant emissions above significant levels as defined in HAR §11-60.1-1. The net emissions increase from the new combustion turbine/HRSG and new boilers are not significant to trigger a BACT analysis for any pollutant. See Table 6 on page 8.

Prevention of Significant Deterioration (PSD):

The Chevron Hawaii Refinery is classified as a *major stationary source,* however, the proposed project is not classified as a *major modification* since it does not result in a significant net emissions increase, as defined in HAR §11-60.1-131. Therefore, a PSD review is not applicable. See Table 6 on page 8.

Consolidated Emissions Reporting Rule (CERR):

40 CFR Part 51, Subpart A - Emission Inventory Reporting Requirements, determines CER based on the emissions of criteria air pollutants from Type A and Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the CER triggering levels as shown in Table 1 below.

TABLE 1 – CERR/IN-HOUSE REPORTING APPLICABILITY

Pollutant	Type A CER Triggering Levels [1,2] (tpy)	Type B CER Triggering Levels [1] (tpy)	Pollutant	In-house Total Facility Triggering Levels [3] (tpy)
NO_x	≥2500	≥100	NO_x	≥25
SO_x	≥2500	≥100	SO_x	≥25
CO	≥2500	≥1000	CO	≥250
$PM_{10}/PM_{2.5}$	≥250/250	≥100/100	PM/PM_{10}	≥25/25
VOC	≥250	≥100	VOC	≥25
Pb		≥5	Pb	≥5
			HAPS	≥5

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

The Chevron Hawaii Refinery exceeds the Type A 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 pollutant exceeding in-house triggering levels. The emissions from the Chevron Hawaii Refinery exceed the in-house triggering levels and thus annual emissions reporting is required for in-house recordkeeping purposes.

Compliance Assurance Monitoring (CAM):

40 CFR Part 64

Applicability of the CAM rule is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for a source to be subject to CAM, each source must:

- Be located at a major source per Title V of the Clean Air Act Amendments of 1990;
- Be subject to federally enforceable applicable requirements;
- Have pre-control device potential emissions that exceed applicable major source thresholds;
- Be fitted with an “active” air pollution control device; and
- Not be subject to certain regulations that specifically exempt it from CAM.

Emission units are any part or activity of a stationary source that emits or has the potential to emit any air pollutant.

As shown in the table below, Compliance Assurance Monitoring (CAM) for the proposed project is not applicable. Please note that the applicant is proposing to install and operate a NO_x CEMS for the combustion turbine in addition to the continuous monitoring system for the water-to-fuel ratio required by NSPS Subpart KKKK.

TABLE 2 – CAM APPLICABILITY

CAM Criteria	Combustion Turbine/HRSG	Boilers
Be located at a major source per Title V of the Clean Air Act Amendments of 1990	Yes	Yes
Be subject to federally enforceable applicable requirements	Yes	Yes
Have pre-control device potential emissions that exceed applicable major source thresholds	Yes	Yes
Be fitted with an "active" air pollution control device	Yes	No
Not be subject to certain regulations that specifically exempt it from CAM.	No [1]	No [2]
Subject to CAM?	No	No

[1] The combustion turbine/HRSG is subject to a post 11/15/90 NSPS, i.e., 40 CFR Part 60 Subpart KKKK, which exempts it from CAM.

[2] The boilers are subject to a post 11/15/90 NESHAP, i.e., 40 CFR Part 63, Subpart DDDDD, which exempts them from CAM.

Major Source Applicability:

A *major source* as defined in HAR §11-60.1-1, has the potential to emit 100 TPY or more of any air pollutant, or 10 TPY or more of any individual HAP or 25 TPY or more of any combination of HAPs. The Chevron Hawaii Refinery is classified as a major source (see Table 6).

Synthetic Minor Applicability:

A synthetic minor source is a facility that is potentially major (as defined in HAR §11-60.1-1), but is made nonmajor through federally enforceable permit conditions. The Chevron Hawaii Refinery is a major source and not a synthetic minor.

Insignificant Activities:

This project did not propose any insignificant activities as defined in HAR §11-60.1-82.

Alternate Operating Scenarios:

This project did not propose any alternate operating scenarios.

Project Emissions:

TABLE 3 – VENDOR GUARANTEED EMISSION RATES FOR TURBINE/HRSG [1, 2]

Pollutant	Units	Refinery Gas Fuel		Naphtha Fuel[5]	
		With Duct Firing	Without Duct Firing	With Duct Firing	Without Duct Firing
NOx (as NO_2)	lb/hr	13.70	11.06	12.79	10.15
CO[4]	lb/hr	7.66	5.02	28.38 (11.6)	25.74 (11.6)
VOC[3]	lb/hr	2.49	1.44	6.95	5.90

[1] Emissions data shown in this table correspond to an ambient temperature of 75°F.
[2] Turbine emissions guaranteed for 80-100% load.
[3] VOC emissions shown in this table are the Unburned Hydrocarbons (UHC) data (as methane) provided by Deltak, which are conservatively assumed to be 100% VOC.
[4] The applicant wishes to replace the vendor-guaranteed maximum hourly emissions of CO with a value of 11.6 lb/hr, and will accept permit conditions limiting cogeneration CO emissions to this level, which is approximately equivalent to a stack gas concentration of 60 ppmvd CO @ 15% O_2.
[5] The duct burner will be run exclusively with RFG fuel. Stack emissions totals include duct firing at the maximum capacity of the burner with RFG.

Emissions of SO_x from the proposed combustion turbine/HRSG were estimated based on mass balance calculation. For the proposed combustion turbine/HRSG, a sulfur content of 0.03% by weight for naphtha and 160 ppmv H_2S for RFG were assumed.

Emission of particulate matter emissions from the proposed combustion turbine/HRSG were not provided by the vendor. In addition, emission factors specifically applicable to these types of equipment burning RFG and naphtha fuels are not available in standard US EPA references, such as AP-42. Therefore, AP-42 emission factors for gas turbines using natural gas and diesel fuels were used to quantify the expected emissions PM_{10} from the new turbine on RFG and naphtha fuels, respectively. Maximum fuel flow rates provided by the vendor were assumed for the combustion turbine (45.70 MMBtu/hr (HHV) for RFG and 44.88 MMBtu/hr (HHV) for naphtha). The maximum duct burner duty rate (48.86 MMBtu/hr, HHV basis) and the burner PM_{10} emission factor in lb/MMBtu provided by the vendor were multiplied to obtain the maximum hourly emission rates. Continuous year-round operation at the maximum combustion rates for the combustion turbine/HRSG was assumed. The highest of the calculated annual values, corresponding to the turbine on 100% naphtha fuel with duct firing on RFG has been used to provide a conservatively high estimate of annual PM_{10} emissions from the combustion turbine/HRSG.

TABLE 4 – VENDOR GUARANTEED EMISSION RATES PER BOILER [1]

Pollutant Emission Rate	LSFO	RFG	Total Emission Rate [1,2]
	lb/MMBTU	lb/MMBTU	lb/hr
NO_x (as NO_2)	0.32	0.042	18.22
CO	0.08	0.073	7.81
PM_{10} [3]	0.03	0.03	2.97
VOC	0.005	0.004	0.447

[1] Emissions based on 12% flue gas recirculation and an expected boiler feedwater temperature of 250 ºF

[2] Maximum annual boiler emission rate based on operation at 99 MMBtu/hr/boiler with 51.1% of annual fuel energy from LSFO and 48.9% from RFG

[3] An emission rate of 0.03 lb/MMBtu for PM_{10} has been used for all boiler calculations, since this will represent the upper limit of particulate emissions that can be permitted pursuant to NSPS Subpart Dc and NESHAP Subpart DDDDD.

Emissions of sulfur oxides (SO_x) from the two boilers were estimated based on mass balance calculations. For the boilers, a sulfur content of 0.5% by weight for LSFO and 160 ppmv H_2S for RFG were assumed.

TABLE 5 - CONTEMPORANEOUS EMISSIONS INCREASES AND DECREASES IN THE LAST FIVE YEARS

YEAR	DESCRIPTION	TOTAL EMISSIONS (TPY)				
		PM/PM_{10}	SO_x	CO	NO_x	VOC
2002	Installation of domes on Tanks 249/250					-16 [1]
2003	FCC Revamp Project	-90.5	38.9	37.1	36.6	0.4
2005	FCC SO_2 Reduction		-10 [1]			
2006	Flare Vapor Recovery Project	0	-210.8 [1]	-33.6	-148.0	-1.2
	Net change in Facility Emissions	-90.5	-181.9	3.5	-111.4	-16.8
	Net change in Facility Emissions (creditable)	-90.5	38.9	3.5	-111.4	-0.8

[1] Not a creditable change

TABLE 6 - PROJECT EMISSIONS

EQUIPMENT	TOTAL EMISSIONS (TPY)				
	PM/PM_{10}	SO_2	CO	NO_x	VOC
New Turbine/HRSG	4.68	10.06	50.8	60.0	30.4
New Replacement Boilers	26.0	232.0	66.6	159.6	3.9
New Turbine/HRSG + New Replacement Boilers	30.68	242.06	117.4	219.6	34.3
Old Boilers (Boilers F-5201, F-5202 and F-5203)	26.7	241.2	22.4	146.9	3.8
Net Emissions Increase = New Turbine/HRSG + New Replacement Boilers – Old Boilers	4.00	0.9	95.0	72.8	30.5
Net Contemporaneous Emissions Change [1]	-90.5	38.9	3.5	-111.4	-0.8
Net Emissions Increase = New Turbine/HRSG + New Replacement Boilers – Old Boilers + Contemporaneous Emissions Changes [2]	**-86.5**	**39.8**	**98.5**	**-38.6**	**29.7**
Significance Level	15	40	100	40	40
Greater than Significance Level?	no	no	no	no	no

[1] See Table 5.

[2] Net emissions change were determined by subtracting total annual average 2001-2002 emissions due to Boilers F-5201, F-5202 and F-5203 from the maximum potential annual emissions from the proposed hybrid cogeneration plant (two boilers burning 51.1% LSFO and 48.9% RFG plus combustion turbine with HRSG and duct burner) plus contemporaneous emission change . Negative values indicate net emissions decrease.

TABLE 7 - EMISSIONS OF HAZARDOUS AIR POLLUTANTS

Hazardous Air Pollutant	Maximum Potential Emissions for Turbine/HRSG Unit (lb/hr)		Maximum Potential Emissions for Boilers (lb/hr)		Retiring Boilers (lb/hr)	
	RFG Firing	Naphtha Firing	RFG Firing	LSFO Firing	RFG Firing	LSFO Firing
1,3-Butadiene	4.07E-05	7.39E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acetaldehyde	3.78E-03	1.95E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acrolein	6.05E-04	3.13E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Antimony	0.00E+00	0.00E+00	0.00E+00	3.47E-03	0.00E+00	4.07E-03
Arsenic	0.00E+00	4.94E-04	1.52E-05	8.71E-04	1.02E-05	1.02E-03
Benzene	1.13E-03	3.05E-03	1.60E-04	1.41E-04	1.08E-04	1.66E-04
Beryllium	0.00E+00	1.39E-05	9.12E-07	1.83E-05	6.15E-07	2.16E-05
Cadmium	0.00E+00	2.15E-04	8.36E-05	2.63E-04	5.64E-05	3.09E-04
Chromium	0.00E+00	4.94E-04	1.06E-04	5.58E-04	7.17E-05	6.55E-04
Cobalt	0.00E+00	0.00E+00	6.38E-06	3.97E-03	4.30E-06	4.67E-03
Dichlorobenzene	0.00E+00	0.00E+00	9.12E-05	0.00E+00	6.15E-05	0.00E+00
Ethylbenzene	3.03E-03	1.56E-03	0.00E+00	4.20E-05	0.00E+00	4.93E-05
Formaldehyde	4.97E-02	5.01E-02	5.70E-03	2.18E-02	3.84E-03	2.56E-02
Hexane	0.00E+00	0.00E+00	1.37E-01	0.00E+00	9.22E-02	0.00E+00
Hydrochloric Acid	0.00E+00	0.00E+00	3.80E-05	0.00E+00	2.56E-05	0.00E+00
Lead	0.00E+00	6.28E-04	0.00E+00	9.97E-04	0.00E+00	1.17E-03
Manganese	0.00E+00	3.55E-02	2.89E-05	1.98E-03	1.95E-05	2.33E-03
Mercury	0.00E+00	5.39E-05	1.98E-05	7.46E-05	1.33E-05	8.76E-05
Methyl Chloroform (1,1,1-Trichloroethane)	0.00E+00	0.00E+00	0.00E+00	1.56E-04	0.00E+00	1.83E-04
Naphthalene	1.23E-04	1.63E-03	4.63E-05	7.46E-04	3.13E-05	8.76E-04
Nickel	0.00E+00	2.06E-04	1.60E-04	5.58E-02	1.08E-04	6.55E-02
PAH	2.08E-04	1.90E-03	6.74E-06	7.92E-04	4.55E-06	9.31E-04
Phosphorus	0.00E+00	0.00E+00	0.00E+00	6.24E-03	0.00E+00	7.34E-03
Propylene oxide	2.74E-03	1.42E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium	0.00E+00	1.12E-03	1.82E-06	4.51E-04	1.23E-06	5.30E-04
Toluene	1.23E-02	6.35E-03	2.58E-04	4.09E-03	1.74E-04	4.81E-03
Xylene	6.05E-03	3.13E-03	0.00E+00	7.19E-05	0.00E+00	8.45E-05
All HAPS	**7.97E-02**	**1.11E-01**	**1.43E-01**	**1.02E-01**	**9.68E-02**	**1.20E-01**

TABLE 8 – NET CHANGE IN HAZARDOUS AIR POLLUTANT EMISSIONS

Hazardous Air Pollutant	Net Emissions Change* (lb/year)
1,3-Butadiene	6.47
Acetaldehyde	33.13
Acrolein	5.30
Antimony	-20.16
Arsenic	-0.77
Benzene	25.68
Beryllium	0.01
Cadmium	0.22
Chromium	0.91
Cobalt	-23.13
Dichlorobenzene	-0.15
Ethylbenzene	26.26
Formaldehyde	302.75
Hexane	-222.22
Hydrochloric acid	-0.06
Lead	-0.29
Manganese	299.02
Mercury	0.01
Methyl Chloroform (1,1,1-Trichloroethane)	-0.91
Naphthalene	9.90
Nickel	-322.96
PAH	12.05
Phosphorus	-36.33
Propylene oxide	24.02
Selenium	7.20
Toluene	83.45
Xylene	52.60
ALL HAPS	**262.01**

*Net emissions changes determined by subtracting total annual average 2001-2002 emissions due to Boilers F-5201, F-5202 and F-5203 from the maximum potential annual emissions from the proposed project (combustion turbine/HRSG and boilers). Negative values indicate a net emissions decrease will result from the proposed project. See Table 5.

Air Quality Assessment:

The applicant conducted an ambient air quality impact analysis (AAQIA) for the proposed Hybrid Energy Plant. Annual refinery emissions of SO_2, CO and VOC are expected to increase when the proposed project is implemented. However, a net decrease in emissions of PM_{10} and NO_x will occur when the reductions from the existing boilers and other contemporaneous projects at the refinery are considered. Modeling to evaluate the future air quality conditions in the vicinity of the refinery was performed for these pollutants as well, since emissions from the new combustion turbine/HRSG and two new boilers will be released from stacks in different locations and with different dimensions and exhaust characteristics than those from the boilers they will replace.

The applicant conducted dispersion modeling in order to eliminate any question about the potential effects of the proposed Hybrid Energy Plant on ambient air quality near the refinery. Specifically, maximum concentrations due to the Hawaii Refinery operations with the new equipment were estimated for all criteria pollutants and averaging times addressed in Federal and Hawaii ambient air quality standards. The modeling included all existing emission sources within the refinery (except the three retiring boilers) operating at their average level during the two year period 2001-2002, in addition to the new combustion turbine/HRSG and two new boilers. The only existing refinery process that will be affected by the proposed project is the Boiler Plant, since three boilers will be retired after the new combustion turbine/HRSG and new boilers come on-line. Accordingly, the existing Boiler Plant emissions sources were excluded from the total refinery emissions for the simulations to evaluate future maximum short-term and long-term impacts from the proposed Hybrid Energy Plant.

The ISCST3 model was selected to evaluate the criteria pollutant impacts from the proposed Hybrid Energy Plant. The regulatory default settings of the ISCST3 model was selected for the modeling. This includes use of final plume rise, buoyancy-induced dispersion for hot sources, processing of calm wind data, default values for the assumed wind profile exponents and vertical temperature gradients for different atmospheric stability conditions.

The assumptions used in the ISCST3 modeling include the following:

1. Rural Land Use Parameter

2. Meteorological Data

   The 1992 AES meteorological data set was used as provided by the Department of Health. This was the most representative data available.

3. Simple and Complex Terrain

4. Receptor Locations

   a. Receptors were placed on the refinery property line at intervals of 50 meters;
   b. From the refinery property line out to a distance of 1 kilometer beyond the perimeter, a spacing of 100 meters was used;
   c. For distances between 1 and 10 kilometers beyond the perimeter, the spacing was 500 meters;
   d. For distances between 10 kilometers and 15 kilometers beyond the perimeter, the spacing was 1,000 meters; and

e. Additional receptors were selected to coincide with locations of high elevation points in the nearby hills.

5. Downwash

The proximity of stacks within the refinery to buildings, tanks and other large structures can induce a condition known as aerodynamic downwash, whereby plumes emitted from such stacks are drawn into low pressure zones in the lee of these wind obstacles, which can potentially cause relatively high ground level pollutant concentrations close to the source location. To account for this effect, the location coordinates, horizontal dimensions and heights of significant structures within the Hawaii Refinery were determined by site personnel. These data were entered into the U.S. EPA Building Profile Input Program (BPIP) to create a data file with the necessary information for downwash calculations involving the appropriate structures for different wind directions. This BPIP output file was then entered with the other inputs to ISCST3 to accomplish the simulation of plume downwash effects.

6. Background Data

The background data consisted of 2005 data from Kapolei for CO, NO_x, PM_{10}, and SO_2.

Table 11 shows the maximum predicted pollutant concentrations due to refinery point source emissions for the proposed project. This table demonstrates that, even with the conservative assumptions used to represent background concentrations and emissions with the Hybrid Energy Project, the predicted pollutant concentrations in the refinery vicinity are compliant with the Federal and State Ambient Air Quality Standards for all pollutants.

TABLE 9 – PROPOSED PROJECT POLLUTANT EMISSIONS FOR MODELING

Source ID	Source Description	Emissions (tons/year)			
		PM_{10}	SO_2	CO	NO_x
CTG6704	New Turbine/HRSG Train [1]	4.7	10.1	50.8	60.0
FWBOIL1	New Boiler[2]	13.0	116.0	33.3	79.8
FWBOIL2	New Boiler [2]	13.0	116.0	33.3	79.8
CTG6701	Existing Cogen Turbine[3]	2.21	1.55	6.42	31.30
CTG6702	Existing Cogen Turbine[3]	2.21	1.55	6.42	31.30
CTG6703	Existing Cogen Turbine[3]	2.21	1.55	6.42	31.30
F5103	Crude Unit - Atmospheric Furnace[3]	25.56	245.46	17.42	151.29
F5153	Crude Unit - Vacuum Furnace[3]	6.45	101.26	7.20	78.85
F5300	FCC Furnace[3]	0.37	0.26	4.07	4.85
F5600	Hydrogenation Furnace[3]	0.03	0.02	0.32	0.38
F5700	Hydrogen Plant Furnace[3]	0.26	0.18	2.93	3.49
F5930	Isomerization Furnace[3]	0.07	0.15	0.76	0.90
F5950	Isomerization Furnace[3]	0.03	0.02	0.31	0.37
F6003	Asphalt Plant Furnace[3]	0.08	0.06	0.88	1.05
F6262	Acid Plant Furnace[3]	0.14	0.10	1.52	1.81
F6200ABS	Acid Plant Combustion Chamber & Absorber[3]	0.14	0.10	1.61	1.92
FCCPRECP	FCC Precipitator Stack[3]	155.23	462	320.03	224.75
CRUFLARE	Crude Flare F2301[3]	-	11.2	4.1	17.8
FCCFLARE	FCC Flare F2302[3]	-	101.2	36.6	160.8
COOL1	Cooling Tower[3]	0.25			
COOL2	Cooling Tower[3]	0.25			
COOL3	Cooling Tower[3]	0.25			
COOL4	Cooling Tower[3]	0.25			
COOL5	Cooling Tower[3]	0.25			
COOL6	Cooling Tower[3]	0.25			
COOL7	Cooling Tower[3]	0.25			
COOL8	Cooling Tower[3]	0.25			
COOL9	Cooling Tower[3]	0.25			
COOL10	Cooling Tower[3]	0.25			

[1] Emissions for new cogeneration unit are based on continuous, year-round operation at maximum fuel use rates for the turbine/HRSG train with full duct burning and naphtha fuel in turbine and RFG in HRSG.

[2] Emissions for new boilers are based on continuous, year-round operation with 51.1% fuel requirement from LSFO and 48.9% from RFG.

[3] Emissions for all existing sources are based on actual 2001-2002 fuel usage rates.

TABLE 10 – PROPOSED PROJECT STACK PARAMETERS FOR MODELING

Source ID	Source Type	UTM East (m)	UTM North (m)	Base Elevation (m)	Stack Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
CTG6704	New Turbine/HRSG Train	591807	2357070	2.7	24.99	464.26	9.31	1.829
FWBOIL1	New Boiler	591796	2357082	2.7	24.99	449.82	19.32	0.905
FWBOIL2	New Boiler	591780	2357074	2.7	24.99	449.82	19.32	0.905
CTG6701	Existing Cogen Turbine	591824	2357038	2.53	21.34	477.05	20.9	1.2
CTG6702	Existing Cogen Turbine	591819	2357047	2.56	21.34	477.05	20.9	1.2
CTG6703	Existing Cogen Turbine	591814	2357057	2.71	21.34	477.05	20.9	1.2
F5103	Crude Unit - Atmospheric Furnace	592053	2356683	2.96	42.9	450	12.45	1.5
F5153	Crude Unit - Vacuum Furnace	592053	2356683	2.96	42.9	450	12.45	1.5
F5300	FCC Furnace	591896	2356928	2.74	42.8	651	6.8	1.7
F5600	Hydrogenation Furnace	592046	2356626	2.71	38.1	1094	2	1.5
F5700	Hydrogen Plant Furnace	592058	2356642	2.87	38.1	533	1.9	1.8
F5930	Isomerization Furnace	591979	2356793	2.83	24.4	700	0.7	0.9
F5950	Isomerization Furnace	591976	2356791	2.8	24.4	700	0.7	0.9
F6003	Asphalt Plant Furnace	592405	2356492	3.05	9.1	408	13.2	0.3
F6262	Acid Plant Furnace	591880	2356433	0.91	19.4	604	4.6	0.6
F6200ABS	Acid Plant Combustion Chamber & Absorber	591907	2356434	1.1	37.49	352.6	2.95	0.91
FCCPRECP	FCC Precipitator Stack	591894	2356970	2.87	38.2	561	32.6	1.5
CRUFLARE	Crude Flare F2301	592207	2356412	2.56	47.34	1273	20	0.059
FCCFLARE	FCC Flare F2302	592141	2356378	2.13	47.75	1273	20	0.195
COOL1	Cooling Tower	592075	2356445	2.26	18.36	318	8	8
COOL2	Cooling Tower	592080	2356436	2.26	18.36	318	8	8
COOL3	Cooling Tower	592085	2356450	2.35	18.36	318	8	8
COOL4	Cooling Tower	592089	2356441	2.35	18.36	318	8	8
COOL5	Cooling Tower	592095	2356455	2.41	18.36	318	8	8
COOL6	Cooling Tower	592099	2356446	2.41	18.36	318	8	8
COOL7	Cooling Tower	592105	2356459	2.5	18.36	318	8	8
COOL8	Cooling Tower	592109	2356451	2.47	18.36	318	8	8
COOL9	Cooling Tower	592114	2356464	2.59	18.36	318	8	8
COOL10	Cooling Tower	592119	2356456	2.53	18.36	318	8	8

TABLE 11 – AMBIENT AIR QUALITY IMPACTS FROM PROPOSED PROJECT

Pollutant	Averaging Period	1992 Maximum Modeled Concentration			Measured Background Concentration ($\mu g/m^3$)	Maximum Total Concentration ($\mu g/m^3$)	SAAQS[1] ($\mu g/m^3$)	Percent of Standard
		$\mu g/m^3$	UTM X (m)	UTM Y (m)				
PM_{10}	Annual	0.52	591739	2356538	15	15.52	50	31.04
	24-hour	9.37	593500	2361000	53	62.37	150	41.58
SO_2	Annual	5.80	591739	2356538	2	7.80	80	9.75
	24-hour	49.55	593500	2360500	21	70.55	365	19.33
	3-hour	140.79	592000	2361000	64	204.79	1,300	15.75
NO_2	Annual	4.48	591739	2356538	9	13.48	70	19.26
CO	8-hour	50.61	594250	2360250	1,055	1,105.61	5,000	22.11
	1-hour	93.11	592500	2361000	1,710	1,803.11	10,000	18.03

[1] Only the State Ambient Air Quality Standards are shown as they are the same as or more restrictive than the National Ambient Air Quality Standards.

Significant Permit Conditions:

1. Significant permit conditions for the combustion turbine/HRSG included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of NSPS Subparts A, J, and KKKK. The applicant also proposed installing and operating a NO_x CEMS for the combustion turbine in addition to the continuous monitoring system for the water to fuel ratio required by NSPS Subpart KKKK.

2. Significant permit conditions for the combustion turbine included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of MACT Subparts A and YYYY.

3. Significant permit conditions for the boilers included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of NSPS Subparts A, J, and Dc.

4. Significant permit conditions for the boilers included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of MACT Subparts A and DDDDD.

5. Significant permit conditions for all valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges or other connectors in VOC service included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of NSPS Subparts A and GGG.

6. Significant permit conditions for all individual drain systems included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of NSPS Subparts A and QQQ.

7. Significant permit conditions for all pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems in organic hazardous air pollutant service included incorporating the emission limits, monitoring requirements, test methods and procedures, and reporting/recordkeeping requirements of MACT Subparts A and CC.

Conclusion and Recommendations:

Recommend issuing an initial covered source permit for the proposed Hybrid Energy Plant. The emissions from the plant are not significant to trigger PSD. The ambient air quality impacts from the proposed Hybrid Energy Plant are within the State and Federal Ambient Air Quality Standards as the modeling analysis the applicant submitted was very conservative since all of the existing sources were included in the modeling analysis. Issuing an initial covered source permit (CSP No. 0088-02-C) versus amending the existing covered source permit (CSP No. 0088-01-C) is recommended as the existing covered source permit (CSP No. 0088-01-C) is currently being amended. A 30-day public comment period and a 45-day EPA review period are also required.

Reviewer: Darin Lum
Date: 4/07