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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

JUL 08 2013

HEALTHY AIR LIVING™

Mr. John Heiser
California Energy Commission
1516 9th Street (MS-40)
Sacramento, CA 95814-5512

Re: Notice of Final Determination of Compliance (FDOC) for Hydrogen Energy California, LLC (Docket # 08-AFC-08A)
Facility: S-7616, Project: 1121903

Dear Mr. Heiser:

The District has made its Final Determination of Compliance for Hydrogen Energy California, docket # 08-AFC-08A. This letter serves as our notification of our final action. The FDOC is available online at http://www.valleyair.org/notices/public_notices_idx.htm#S-1121903.

The District made its Preliminary Determination of Compliance (PDOC) on 2/7/13. Notice of our preliminary decision was published on 2/13/13. Numerous comments were received on the PDOC, including multiple non-air related comments and concerns about the project. All comments received are included in Appendix M of the FDOC. A summary of the comments and responses is included in Appendix N of the FDOC. The FDOC reflects changes made to the PDOC that were made in response to comments received. The changes reflected in the FODC were minor and did not significantly change permitted emission levels, nor did they affect the basis of the District's decision.

If you have any questions regarding the above response or require additional clarification please contact Mr. Leonard Scandura of the Permit Services Department at 661-392-5500.

Sincerely,

David Warner
Direct of Permit Services

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NOTICE OF FINAL ACTION FOR THE ISSUANCE OF A FINAL DETERMINATION OF COMPLIANCE AND PREVENTION OF SIGNIFICANT DETERIORATION NOTIFICATION

NOTICE IS HEREBY GIVEN that the Air Pollution Control Officer has made its Final Determination of Compliance (FDOC) for Hydrogen Energy of California LLC's proposed installation of a power generation facility that uses integrated gasification combined cycle (IGCC), to produce a hydrogen-rich synthesis gas from a blend of coal or petroleum coke to power one combined-cycle combustion turbine generator. The facility will generate a total net output of up to a nominal 300 megawatts (MW) (up to a nominal 431 MW gross output) in a combined cycle power block; manufacture of up to 1 million tons per year of nitrogen-based products in an integrated fertilizer manufacturing complex; and capture a stream that is comprised primarily of carbon dioxide (C02), a greenhouse gas, and transport it by pipeline to a neighboring oilfield for enhanced oil recovery (EOR) and sequestration. The proposed project is to be located at Section 10, Township 30S, Range 24E, approximately 1.5 miles northwest of Tupman in western Kern County.

The project is subject to the requirements of Rule 2201 (New and Modified Stationary Source Review) and Rule 2410 (Prevention of Significant Deterioration). The proposed installation will result in significant emission increases of 158.9 ton NO2/year, 272.4 ton CO/year, 90.1 ton PM/year, 90.1 ton PM10/year, and 593,655 ton CO2e/year which are subject to the requirements of Rule 2410. There is no increment consumption of any attainment pollutant.

The FDOC reflects changes made to the Preliminary Determination of Compliance in response to comments received. The changes reflected in the FDOC were minor and did not significantly change permitted emission levels nor did they affect the bases for our decision. Our FDOC has been forwarded to the California Energy Commission for their use in the power plant licensing process. More information on the CEC licensing process for the HECA facility can be found at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/notices/index.html.

The analysis of the regulatory basis for the District's action on the HECA Proposal (Project #S-1121903) is available for public inspection at any District office (the Bakersfield office is located at 34946 Flyover Court), or on the District Website at http://www.valleyair.org/notices/public_notices_idx.htm#S-1121903.

For more information in English or Spanish about the District decision including our responses to comments or to receive a printed copy of the FDOC please contact Homero Ramirez of the Permit Services Department at (661) 392-5616 or by email at Homero.Ramirez@valleyair.org.

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Hydrogen Energy California Project
California Energy Commission
Application for Certification Docket #: 08-AFC-8A

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Date:	July 5, 2013
Project #:	S-1121903
Application #'s:	S-7616-17-0 through '-40-0
Submitted:	June 4, 2012
Deemed Complete:	August 30, 2012

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I. Proposal

Hydrogen Energy California, LLC (HECA) is seeking a Determination of Compliance from the San Joaquin Valley Air Pollution Control District for the installation of a power generation facility that uses integrated gasification combined cycle (IGCC), a technology that turns a fuel blend consisting of 75 percent western sub-bituminous coal and 25 percent petroleum coke (petcoke) into a synthesis gas (syngas). The facility will gasify the fuel blend to produce hydrogen-rich syngas, which will be used to generate electricity in a combined cycle power block; manufacture nitrogen-based products in an integrated fertilizer manufacturing complex; and capture a stream that is comprised primarily of carbon dioxide (CO2), a greenhouse gas, and transport it by pipeline to a neighboring oilfield for enhanced oil recovery (EOR) and sequestration.

HECA is subject to licensing approval by the California Energy Commission (CEC). The CEC is the sole authority that has discretionary approval of this project. Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review, and is intended to provide comment and guidance to the CEC on the proposal's compliance with air quality requirements. With this action the District is providing its Final Determination of Compliance to the CEC.

The CEC is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA). For purposes of CEQA the District is the commenting agency.

II. Applicable Rules

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410 Prevention of Significant Deterioration (4/16/11, effective 11/26/12)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2540 Acid Rain Program (11/13/97)
Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001 New Source Performance Standards (4/14/99)
- Subpart GG - Standards of Performance for Stationary Gas Turbines
- Subpart KKKK - Standards of Performance for Stationary Gas Turbines
- Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- Subpart Ga - Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011
- Subpart Y - Standards of Performance for Coal Preparation and Processing Plants

Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart A - General Provisions (Section 60.18 – General Control Device and Work Practice Requirements)

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Emissions (RICE)
Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4304 Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters (10/19/95)
Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4311 Flares (6/18/09)
Rule 4320 Advanced Emissions Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4351 Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines – Phase 2 (8/18/11)
Rule 4703 Stationary Gas Turbines (9/20/07)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 7012 Hexavalent Chromium - Cooling Towers (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 9110 and 40 CFR Part 93 General Conformity (10/20/94)
Public Resources Code 21000-21177 - California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387 – CEQA Guidelines
Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment
Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines
CH&SC 42301.6 School Notice
CH&SC 44300 (Air Toxic “Hot Spots”)

III. Project Location

The site is located approximately 7 miles west of outermost edge of the city of Bakersfield and approximately 1.5 miles northwest of the unincorporated community of Tupman in western Kern County. The equipment will be located in Section 10, Township 30S, Range 24E. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Combined Cycle Power Generating System (S-7616-26-0)

Summary

The power-generation equipment used for this project is similar to a conventional natural-gas combined-cycle plant, with the notable exception that substantial heat integration with the gasification process is included to maximize the recovery of useful energy both for internal and external process use and power generation. The combined cycle power block will include one Mitsubishi Heavy Industries (MHI) M501GAC, a G-class, air-cooled advanced combustion turbine (CT), one steam turbine (ST), and one generator (Gen) – in a single-shaft configuration, as well as, one heat recovery steam generator (HRSG), and a water-cooled surface condenser. The CT/ST/Gen and HRSG will convert chemical energy contained in the hydrogen-rich syngas fuel to electricity through the shaft power developed by the CT/ST/Gen, and through the thermal energy recovered from the CT exhaust. This exhaust gas is converted to high-energy steam in the HRSG and combined with the high-energy steam recovered in the gasification process to generate additional electricity in the ST. The total gross output of this combined cycle unit is a nominal 431 megawatts (MW) of power.

The major equipment of the Power Block is described in the following sections:

Combustion Turbine and Heat Recovery Steam Generator

Exhaust gas from the combustion turbine is ducted through the HRSG to generate high-energy steam, which produces additional electricity in the ST/Gen. Some of the exhaust gas is also ducted from the HRSG to Gasification to dry the feedstock, and will be discharged at the feedstock dryer stack in the process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. The combustion system is also equipped with separate fuel nozzles for natural-gas firing during startup, shutdown, and equipment outages. The combustion system is designed to achieve low nitrogen oxide (NOx) emissions, while injecting nitrogen diluent and combusting hydrogen-rich fuels. When operating on natural gas, water is injected for NOx control. Natural gas is used during startup and shutdown of the CTG and during periods of unplanned equipment outages (up to 2 weeks per year), but not during normal operations. The table below presents additional information.

The CT exhaust gas, supplemental hydrogen-rich fuel, and pressure swing adsorption (PSA) off-gas for duct-firing are used as energy input into the HRSG.

Combustion Turbine Generator Specifications	
Model	Mitsubishi MHI M501 GAC
Fuels	H_2-rich fuel, natural gas
Inlet Air Cooling	Evaporative coolers
Emissions Control Diluent	Nitrogen for H_2-rich fuel, water injection for natural gas
Ambient Temperature Range	20 °F to 115 °F, average 65 °F
Ambient Pressure	14.54 psia/288' feet above mean sea level
Source: HECA, 2012.	

Duct Firing

Additional steam generation will occur in the duct-firing system in the CT exhaust. The fuel to the duct burner will consist of a combination of hydrogen-rich fuel and off-gas from the PSA unit. The maximum expected firing rate for the duct burner is 360 MMBtu/hr. Backup natural-gas fuel will not be combusted in the duct burner.

Emission Control Systems

HRSG emission control systems are described in detail below.

A selective catalytic reduction (SCR) system is installed in the HRSG to reduce emissions of NOx from the CTG and duct burners to meet BACT requirements. An oxidation catalyst is also installed in the HRSG to reduce CO and VOC emissions in the same exhaust stream to achieve BACT levels. The HRSG stack is provided with a continuous emissions monitoring system (CEMS) to verify compliance with applicable air permitting requirements.

The SCR system reduces NOx emissions from the stack gases in the HRSG. Vaporized ammonia is mixed with dilution air and injected into the CTG exhaust gas upstream of a catalytic system that converts NOx and ammonia to nitrogen and water. This vaporized ammonia will come from the on-site ammonia plant storage tank.

The components in the SCR system are as follows:

- Dilution air blower. The blower delivers fresh air to be combined with the vaporized ammonia.

- Ammonia injection grid. The diluted ammonia is sent to an injection grid, where the ammonia stream is divided among various injection points upstream of a catalyst. The

flow of ammonia to each injection point can be balanced to provide optimum NOx reduction.

- SCR catalyst. The SCR catalyst provides the surface area and the catalyst material for ammonia and NOx to react and form nitrogen and water. The SCR catalyst is installed in a reactor housing in the HRSG at the proper flue gas temperature-point for good NOX conversion.

The oxidation catalyst is installed in the HRSG casing upstream of the SCR ammonia injection location to reduce CO emissions. The catalyst oxidizes the CO and VOCs produced from the CTG and duct burners.

Continuous Emissions Monitoring System (CEMS)

The CEMS records the emissions out of the HRSG stack to comply with local, state, and federal emission requirements. The CEMS typically monitors the NOx, O2, and CO levels. The CEMS uses control system signals for CTG power output and fuel gas to the CTG to calculate the total mass rate of emissions released, and may also be used as part of the ammonia injection controls for the SCR system. The CEMS is designed, installed, and certified in accordance with the applicable SJVAPCD and USEPA standards for analyzer performance, data acquisition, and data reporting.

These systems sample, analyze, and record stack emission data for several specified pollutants. CEMS incorporates data handling and acquisition systems to automatically generate emissions data logs and compliance documentation. Alarms alert operators if stack emissions exceed specified limits. Each CEMS undergoes periodic calibration, audits, and testing to verify accuracy.

In addition to continuous monitoring, the project will perform periodic stack emission tests to verify compliance with emission limits, as required.

Steam Turbine

The ST for this project is an MHI reheat turbine which is coupled to the generator through a clutch, along with the CT on a single shaft. The ST exhaust steam is condensed in a water-cooled condenser.

Cooling Towers

The excess thermal energy in the steam exhausted to the condenser is dissipated in the heat rejection system. This system is comprised of a condenser, a circulating water system, and a multi-cell cooling tower.

The condenser is a shell and tube heat exchanger with the steam condensing on the shell side under a vacuum, and the cooling water flowing through the tubes in a single- or double-pass design. The condensate collects in the condenser hotwell, where it supplies the condensate pumps that feed the HRSG.

The heat in the condenser is picked up by the circulating water system and transferred to the cooling tower. The cooling water system also transfers heat to the cooling tower from the hydrogen-cooled generator, and other power and gasification equipment.

During startup, a separate set of auxiliary cooling pumps supply water from the cooling tower basin and pump it through plate-type closed cooling water (CCW) exchangers, and return the water to the cooling tower fill material. The CCW pumps circulate higher-purity water through the CCW exchangers that cool the water before it removes heat from the closed-circuit cooling water users.

Major Electrical Equipment and Systems

The project will have a 230-kilovolt (kV) air-insulated switchyard for interconnection to a future PG&E switching station. The 230-kV transmission line is sized for the total plant output. Revenue metering is provided in the PG&E switching station.

Startup power for the project is obtained by back-feeding from the 230 kV grid through the main transformer to the unit auxiliary transformers.

The project's auxiliary loads are served by various Power Distribution Centers (PDCs). PDC-1 serves major 13.8 kV loads, including downstream 4160-V and 480-V PDCs, and large motor drivers. Each of the 4,160-volt (V) and 480 V PDCs has a double-ended substation configuration with two 100 percent sized transformers.

Dual 2 MW standby diesel generators provide emergency power to essential services in the event of a power failure.

Medium-voltage (MV) and low-voltage (LV) switchgear, MV and LV motor control centers, 125 V direct-current batteries, chargers, uninterruptable power supply, and Distributed Control System In/Out racks are located indoors in pre-fabricated electrical PDCs with redundant heating, ventilation, air conditioning units. The Major Electrical Equipment will be in accordance with American National Standards Institute/Institute of Electrical and Electronic Engineers/National Electrical Manufacturers Association/American Society for Testing and Materials standards. The electrical system design and installation are in accordance with the National Electrical Code

Feedstock Delivery, Handling, and Storage System:

Rail Unloading and Transfer System (S-7616-17-0):

The applicant proposes to transfer the coal feedstock to the project site by rail unloading and transfer system. However, if the rail unloading system is unavailable to transfer the coal feedstock to the project, the applicant proposes to utilize the truck unloading and transfer system (S-7616-18) described below. For the rail unloading and transfer system, a new industrial railroad spur approximately 5 miles in length will connect the project site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of

the project site. This railroad spur would also be used to transport some HECA products to customers. A rail unloading and transfer system would be constructed at the project site to unload feedstock from unit trains and convey it to the storage barn. This system accomplishes the following objectives.

- Unloads feedstock from unit trains; and
- Conveys the feedstock to storage in the feedstock barn.

The transfer conveyor is fully enclosed for weather protection and to control fugitive dust. The conveyor is provided with belt scales, magnetic separators, metal detectors, and safety switches, as required. All related feedstock transfer buildings are fully enclosed. Dust suppression spray systems and/or multiple dust collection systems are used to control fugitive dust.

Truck Unloading and Transfer System (S-7616-18-0):

Petcoke (and/or coal if the rail unloading transfer system is not available) will be delivered to the project site via over-the-road bottom-dump haul trucks. Truck transport would be via existing roads. In addition, a portion of the products of the HECA facility will be transported to markets by truck. At the project site, petcoke will be unloaded at the truck-dump unloading station. The truck dump has a single hopper below each unloading station. Petcoke from these hoppers is sent to the petcoke storage via belt feeders, unloading conveyor, and transfer conveyors. An as-received sample system is provided with the truck transfer conveyors. The concrete floor under the truck unloading system slopes to a sump. This sump is equipped with an installed sump pump to recycle water back to the wash-down system, or to forward it to the water reclaim system.

Once trucks have unloaded the petcoke, each vehicle exits and passes through a truck wash system, which sprays the entire truck with wash-down water (no soap added), and a specific spray system cleans the wheels. This is done to minimize or eliminate any dust and debris from being carried out and deposited on either the roads inside the project site or on public roads. The wastewater collected under the truck wash is routed to a sump that allows the wastewater to evaporate. Accumulated solids will be removed and disposed in an approved manner as necessary.

Feedstock Storage, Blending, and Reclaim System (S-7616-19-0):

Feedstock, both coal and petcoke, will be stored in a building with separate coal and petcoke storage piles. The coal and petcoke will be reclaimed at a set rate and blended as they are placed on conveyors for transfer from the storage building. The blended feedstock will then be crushed and flow to gasification for further processing.

The transfer conveyor and crushing system between the storage building and gasification block is fully enclosed for weather protection and to control fugitive dust. The conveyor is

provided with belt scales, magnetic separators, metal detectors, and safety switches, as required.

Fluxant will also be unloaded from the trucks and stored in a silo located north of the feedstock barn that will be served by a dust collector. The fluxant will be added to the feedstock on the conveyor at the point where it exits the feedstock storage barn. The fluxant will increase the calcium content of the feedstock to achieve vitreous "glass like" gasification solids.

Feedstock Grinding/Crushing and Drying System (S-7616-20-0)

The MHI gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in silos. The feedstock then flows to the grinding mills, where the particle size is reduced to that required for transport into the gasifier and simultaneously dried. The heat source for feedstock drying is hot turbine exhaust gas from the HRSG. After drying the feedstock, the drying gases flow through a dust collection system, then to the atmosphere. The dried feedstock flows to intermediate storage bins, from which it is transported into the gasifier.

During operations and some phases of the startup and shutdown activities, a portion of the HRSG flue gas will be diverted to the feedstock drying area, filtered through a baghouse, then exhausted from the feedstock dryer stack. As a result, the emissions from the HRSG and coal-dryer stacks are interconnected. The HRSG flue gas that is diverted to the feedstock dryer has emissions already treated by the oxidation catalyst and SCR. The exhaust stream through the feedstock dryer stack is further controlled with a baghouse before being exhausted to the atmosphere.

Gasification System (S-7616-21-0):

Gasifier

The MHI oxygen-blown gasifier is a pressurized, upflow, entrained-flow slagging reactor with a two-stage operation. The MHI gasifier is a dry-feed system; and the reactor internals are protected by a membrane wall.

The reactor consists of two sections (or stages). The feedstock enters the gasifier at two separate points, with one portion being fed into the lower stage together with O2, where it is gasified at high temperature to produce CO and CO2, in addition to water vapor. The temperature generated is sufficiently high to melt the coal ash. The molten coal ash flows down the membrane wall to the bottom of the gasifier, where it is quenched in a water bath and then removed using a lock hopper system.

The gas produced in the first stage rises to the second stage, where the remaining feedstock is added without any additional O2. In this fuel-rich reducing environment, the key reactions that take place are the gasification of char (the carbon-rich by-product of gasified coal) to CO, and the shifting of CO and water to H2 and CO2. In the second stage, heat provided by the hot gas from the first stage is used to drive these endothermic

gasification reactions. As a result, the second stage operates at a lower temperature than the first stage. Completing the gasification reactions at a lower temperature reduces the O2 required and improves the efficiency of the gasifier. The produced syngas exits the second stage through a syngas cooler, generating steam in the process. This steam is used for power generation in the steam turbine of the power block. A cyclone and a filter are used downstream of the syngas cooler to collect the char and recycle it to the lower gasifier section to increase the overall carbon conversion efficiency. The raw syngas leaving the second stage of the gasifier is typically at a temperature of approximately 2,200 °F, hot enough that negligible hydrocarbon gases and liquids are formed.

Syngas Scrubbing, Sour Shift, Low-Temperature Gas Cooling, and Sour Water Treatment

Hot, raw syngas from the gasifier is treated in the syngas scrubber to remove chlorides. Removal of chlorides in the syngas scrubber minimizes the potential to precipitate ammonium chloride in downstream equipment as the syngas is further cooled. The bottoms stream from the syngas scrubber, along with sour water streams from the SRU, is sent to a sour water stripper. The sour gas from the stripper overhead is sent as a feed to the SRU. The stripper bottoms stream is sent to the Wastewater Treatment Unit for additional processing. Scrubbed syngas entering the Sour Shift Unit is rich in CO and water. The Sour Shift Unit employs the water-gas shift (WGS) reaction to convert CO and water to CO_2 and hydrogen. The WGS reaction proceeds as shown below:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The heat from the exothermic shift reaction is used to generate steam or to heat other process streams via cross-exchange, thereby improving overall plant efficiency. The WGS reaction is carried out in a two-stage process. Each of the reactors has a sulfur-tolerant catalyst bed composed of cobalt and molybdenum oxides. This catalyst also promotes the hydrolysis of carbonyl sulfide (COS) to hydrogen sulfide (H_2S).

Hydrogenated tail gas from the SRU is recycled to the Sour Shift Unit. This configuration eliminates a need to remove H_2S from the hydrogenated tail gas and also eliminates the need for atmospheric tail gas emissions.

Hot syngas from the sour shift reaction section is cooled and sent to the ammonia wash column, where it is washed with clean boiler feed water to remove any ammonia present in the syngas. Cooled, shifted, ammonia-free syngas exits the wash column and is sent to the Mercury Removal Unit. The bottoms stream from the ammonia wash column is sent to a separate sour water stripper. Most of the ammonia is concentrated in the stripper overhead stream, which is sent as a feed to the SRU. The stripper bottoms stream is recycled back to the syngas scrubber.

Mercury Removal

In order to minimize potential mercury emissions, this project has incorporated mercury capture technology. Tests of petcoke sources show occasional trace levels of mercury in

the elemental analyses. Western sub-bituminous coals typically contain trace levels of mercury as well. Mercury is removed downstream of the sour shift and low-temperature gas cooling (LTGC) units using activated carbon or activated alumina, and at the feedstock dryer using activated carbon. After mercury removal, the product syngas is treated in the acid gas removal (AGR) unit. These controls will reduce mercury emissions to a level that will comply with the new National Emission Standards for Hazardous Air Pollutants (NESHAP) for IGCC Electric Generating Units.

Acid Gas Removal (AGR)

The term "acid gas" refers to vapor containing significant concentrations of acidic gases such as H_2S and CO_2. This section describes how acid gases are removed from the shifted syngas to produce a hydrogen-rich fuel that feeds the Combined Cycle Power Block. A portion of the hydrogen-rich fuel is also used to generate a high-purity hydrogen stream that serves as a feedstock to the Ammonia Synthesis Unit.

Rectisol® Process Description

In the Rectisol® unit, the shifted sour syngas feed is chilled prior to entering the pre-wash section, in which condensed or dissolved impurities are removed. The gas then flows to the absorber column, where it is contacted with methanol solvent for absorption of H_2S, other sulfur compounds, and CO_2.

Clean, hydrogen-rich fuel (very low in sulfur compounds and CO_2) exits the top of the absorber column. The clean, hydrogen-rich fuel is heated and sent to the Combined Cycle Power Block for use as fuel or to the PSA Unit for further purification.

The hydrogen-sulfide-laden solvent is withdrawn from the absorber column and flashed, with the flash gas recycled to the absorber column, and the separated liquid solvent sent to CO_2 separation columns. CO2-laden solvent from the absorber column is also sent to the CO_2 separation columns.

Separated CO_2 exits the top of the CO_2 separation columns and flows to CO_2 compression equipment. After compression, the CO_2 is transported to the OEHI CO_2 Processing Facility for CO_2 EOR.

The solvent exiting the bottom of the CO_2 separation columns flows to the hot regenerator, where H_2S, other sulfur compounds, and the remaining CO_2 are released from the solvent by increasing the temperature and stripping with methanol vapor generated in a reboiler. The separated acid gas exiting the top of the hot regenerator undergoes further processing in the SRU to recover liquid sulfur as a product.

The regenerated methanol solvent exiting the bottom of the hot regenerator, now CO_{2-} and H_2S-free, is cooled and returned to the absorber column for reuse.

A small portion of the regenerated solvent is sent to the methanol-water column for separation of water and impurities from the methanol by distillation. The methanol-rich

overhead stream from the methanol-water column is returned to the hot regenerator. The separated column bottoms water is cooled and sent to the Wastewater Treatment Unit.

A 600,000 gallon methanol storage tank, for the Rectisol Unit solvent, will be used to supply makeup solvent to the Rectisol Unit and to provide adequate storage capacity for the entire solvent inventory when unit maintenance is required. The size is based on the capacity needed to hold the entire solvent inventory from the unit, as it will need to be purged for maintenance.

Gasification Solids Material Handling System (S-7616-22-0):

Gasification solids are comprised of vitrified (glass-like) material produced by melting the mineral matter in the coal and petcoke, and small amounts of unconverted carbon.

In the collection sump, the gasification solids are separated from the water and are accumulated for off-site transportation by rail or truck.

Gasification Solids

Gasification solids are comprised of the silica, alumina, and other constituents found in coal and petcoke. The high temperature in the gasifier produces a glassy, vitrified solid that is suitable for reuse. Most of the gasifier solids will be transported by rail for beneficial reuse by regional industries. A smaller portion can be transported to nearby industries by truck. It is estimated that gasification solids export would be approximately 75 percent by rail and 25 percent by truck. The planned production rate would be about 840 stpd on a dry basis. The composition of the gasification solids has been estimated based on the anticipated feedstock composition. The table below represents a projected composition of the gasification solids:

Example Composition of Gasification Solids	
Determination	**Results wt%**
Silicon (SiO_2)	56.3
Aluminum (Al_2O_3)	22.6
Iron (Fe_2O_3)	7.07
Calcium (CaO)	8.49
Magnesium (MgO)	1.12
Sulfur (SO_3)	0.11
Sodium (Na_2O)	0.69
Potassium (K_2O)	0.96
Titanium (TiO_2)	0.96
Phosphorus (P_2O_5)	0.02
Manganese (MnO)	0.04
Carbon (C)	<0.1
Mercury (Hg)	0.00 (below detectable)
Source: HECA, 2012.	

Gasification solids are dewatered, and the solids are accumulated for shipment. Upon exiting the gasifier, the liquids are recovered and returned for reuse in the process. The dewatered gasification solids will be retained in on-site storage until sufficient quantities are accumulated to facilitate their economical transportation. On-site gasification solids storage has the capacity for 7 days of production.

Sulfur Recovery and Tail Gas Compression System (S-7616-23-0):

Sulfur Recovery and Tail Gas Compression Unit

Acid gas from the acid gas removal (AGR) unit, sour gas streams from the two sour water strippers, and various plant vents are fed to a sulfur recovery unit (SRU). A portion of the H_2S in the feed is oxidized to SO_2 in a reaction furnace. The resulting SO_2 reacts with the remaining H_2S in the correct ratio to form elemental sulfur. These reactions proceed as shown below:

$$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O$$

$$2\ H_2S + SO_2 \leftrightarrow 3\ S + 2\ H_2O$$

Hot effluent gases from the reaction furnace are cooled in the waste heat boiler by generation of 600 pounds per square inch gauge (psig) steam. The tempered effluent gas is sent to the first condenser, where the temperature is decreased further to condense and recover elemental sulfur. Low-pressure steam is generated in the first condenser. Gas leaving the first condenser is then reheated before entering a catalytic reactor to further promote the H_2S and SO_2 reaction to elemental sulfur, followed by a condenser to recover additional sulfur. One additional reheater, reactor and condenser follow.

Sulfur recovered in the three condenser stages is sent to a sulfur degassing unit to reduce the concentration of H_2S dissolved in the sulfur product. After degassing, the liquid sulfur product is sent to a storage tank and ultimately shipped from the facility via rail or truck.

SRU effluent gases exiting the final condenser are directed to the tail gas unit (TGU) hydrogenation equipment, which converts the various sulfur compounds remaining in the gas, back to H_2S. Water is condensed out of the hydrogenated tail gas in a quench tower, after which it is compressed and recycled to the sour shift unit. This configuration minimizes sulfur emissions from the facility and eliminates the need for a TGU amine section. This configuration also recovers the CO_2 that would be emitted by a conventional TGU.

The SRU will include both ammonia-destruction and O_2-enrichment technology in the reaction furnace, in addition to the degassing technology used in treatment of the product sulfur. Oxygen enrichment technology uses high-purity O_2 rather than air in the combustion section of the SRU, thereby decreasing the volumetric flow of gas through the entire unit. The use of O_2 increases the temperature in the reaction furnace to a level that destroys the ammonia present in the feed gases. Ammonia destruction technology is a critical part of the SRU design. Complete destruction of ammonia in the reaction furnace helps to prevent the potential for ammonia salts to foul downstream equipment.

Sulfur Storage and Handling

As stated above, the degassed liquid sulfur product is stored in a tank for shipment via railcars or tank trucks.

Tail Gas Thermal Oxidizer

Associated with the operation of the sulfur recovery process, the project will incorporate a thermal oxidizer on the TGU. During normal operation, the thermal oxidizer is maintained in a hot standby condition only. The thermal oxidizer will serve as a control device to oxidize any remaining H_2S (after scrubbing) and other vent gas that is generated during startups, shutdowns, and times of non-delivery of CO_2 product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) may be directed to the thermal oxidizer during operation to prevent nuisance odors.

The thermal oxidizer will also be used to dispose of sulfur bearing waste gas during intermittent post-shutdown SRU passivation. In this operation natural gas is fired in the SRU burners to oxidize and remove residual sulfur, for safety reasons, prior to opening the process equipment for major maintenance such as catalyst changeout. This operation is expected to occur no more than once per year, with each event lasting no more than 24 hours.

Finally, the TGTO will be used to safely oxidize and dispose of H2S, SO2, and sulfur vapor from the occasional "presulfiding" of tail gas hydrogenation catalyst. Presulfiding, which activates new catalyst oxide loaded in the reactor prior to normal operation, consists of

recirculating steam-heated hydrogen and nitrogen through the hydrogenation catalyst. The hydrogen reacts with a layer of elemental sulfur on the fresh catalyst material to form sulfides which activate the catalyst. A purge is withdrawn from the recirculating hydrogen stream to remove H2S, SO2, and other sulfur products and direct them to the TGTO for safe disposal. This operation is expected to occur less than once per year, with each event lasting less than 24 hours.

The thermal oxidizer operates at high temperatures, and provides sufficient residence time to ensure essentially complete destruction of reduced sulfur compounds like H_2S to SO_2. The thermal oxidizer fires natural gas continuously to reach and maintain the required operating temperature for proper thermal destruction. Pollutant emissions are generated from the firing of natural gas and the periodic oxidation of vent gas during SRU startup.

CO2 Recovery and Vent System (S-7616-24-0):

The CO2 venting system consists of a CO2 vent header, vent KO drum, and a CO2 vent stack. The system is used to vent incombustible, high-purity CO2. The vent gas is generated from reliefs, startup/shutdown vents, and venting when the CO2 compression, transportation, or injection system is unavailable.

Natural Gas-Fired Auxiliary Boiler (S-7616-25-0):

The auxiliary boiler is a pre-engineered shop-fabricated package boiler that will provide steam for pre-startup equipment warm-up and for other miscellaneous purposes when steam from the Gasification Block or HRSG is not available. During typical operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no sparging), and will not have emissions. When operating, the boiler will produce a maximum of about 150,000 pounds per hour of steam and will be fueled by natural gas. The boiler will be equipped with low-NOx burners and SCR to minimize emissions.

Cooling Towers (S-7616-27-0, -28-0, and -29-0):

Mechanical draft cooling towers are used for indirect heat rejection where low process outlet temperatures are critical to overall plant efficiency. Mechanical draft cooling towers serve multiple heat loads in more than one process unit.

The project has three mechanical draft cooling towers (one for the Gasification Block/Process Units, one for the ASU, and one for the Combined Cycle Power Block) that are described below. The cooling towers use treated water from the water treatment plant as makeup. Cooling-tower blowdown from the cooling towers is directed to the water treatment plant.

Power Block Cooling Tower

The largest heat rejection load in this project is the steam turbine generator surface condenser in the combined cycle power block. The main cooling water pumps supply water from the cooling tower basin and pump it through the surface condenser tubes and back to

the top of the cooling tower cells. The return water flows into distribution piping below high-efficiency drift eliminators and above the cooling tower fill material. Electric motor driven-induced draft fans move air up through the tower fill material, contacting the cooling water with air and promoting evaporative cooling. A chemical feed system will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system for alkalinity reduction to control the tendency for scaling. The acid feed system will consist of storage and two full-capacity metering pumps. A polyacrylate solution is also fed into the circulating water system to inhibit scale formation. This system also requires storage, and two full-capacity metering pumps. Sodium hypochlorite is added to prevent biofouling in the circulating water system. The system requires storage, and two full-capacity metering pumps.

The cooling tower is provided with high-efficiency drift eliminators designed to reduce drift to no more than 0.0005 percent of the circulating water flow rate.

Gasification Block/Process Units Cooling Tower

The design of the Process Cooling Water System is similar to that of the Power Block Cooling Water System described above. The major heat rejection duties are from the CO2 compressor and the AGR refrigeration unit. This compressor is electricity driven. Cooling water is also supplied to the Gasification, Shift, LTGC, SRU/TGU, SWS, Manufacturing Complex, and other miscellaneous users. The process cooling tower has a cooling water basin, pumps, and piping system.

The tower is supplied with high-efficiency drift eliminators designed to reduce drift to no more than 0.0005 percent of circulation.

Air Separation Unit Cooling Tower

The ASU cooling tower will be owned and operated by a third party Industrial Gas Company (IGC). This project will supply the IGC with treated makeup water, and will also treat the ASU cooling tower blowdown in the project's water treatment plant. The following description reflects the IGC's cooling water system design.

The ASU cooling water system design is also similar to that of the power block cooling water system. The major heat rejection duties are from the main air compressor intercooler and aftercooler, the booster air compressor intercooler, and the nitrogen compressor intercooler. These compressors are electricity driven. The ASU cooling tower is located in the ASU near the cooling loads. The ASU cooling tower has separate pumps and piping systems and is operated independently of the other cooling water systems.

The ASU cooling tower is supplied with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

Flares (S-7616-30-0, -31-0, and -32-0):

Flaring will occur only during startup and shutdown operations or during emergencies. The previous design (the previous HECA proposal, project S-7616/S-1093741) required regular rotation of three gasifiers into and out of service to facilitate periodic maintenance of the gasifier refractory and other critical gasifier system components. The rotation of each gasifier into service after maintenance required flaring of syngas from the time of light-off until the syngas was up to pressure and within specification. The new design uses a single, 100-percent-capacity MHI gasifier with an internal membrane wall that requires significantly less maintenance, eliminates rotations, and requires less syngas flaring events than a refractory-lined gasifier.

Although the plant is designed to avoid flaring during steady-state operations, flares are needed to protect the plant operators and equipment. The plant employs three pressure-relief systems and their corresponding flares (Gasification, Rectisol®, and SRU) for this purpose. All three flares are conventional elevated flares, and will be provided with natural gas assist as required. Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment during upsets and emergencies. The flares also allow safe venting of equipment during routine startup and shutdown operations.

During non–startup plant operation, the three flares will be operated in a standby mode with only minimal emissions from the natural-gas pilot flames. As explained below, the gasifier, Rectisol® and SRU flares will also be used to occasionally flare excess startup gases in a safe manner.

Gasification Flare:

The gasification unit is served with an elevated flare to safely flare excess gas during gasifier startup operations or during upset conditions. Syngas sent to the flare during planned flaring events is filtered, water-scrubbed, and sulfur-free. Flaring of untreated syngas or other streams within the plant will only occur as an emergency safety measure during unplanned plant upsets or equipment failures.

Sulfur Recovery Unit Flare

The SRU flare will be used to safely dispose of gas streams containing sulfur during startup and shutdown (as described further in this section) and gas streams containing sulfur during unplanned upsets or emergency events. Acid gas derived from the AGR and the sour water stripper (SWS) overhead is normally routed to the SRU for recovery as elemental sulfur. During cold plant startup of the gasification, AGR, and shift units, these acid gas streams will be diverted to the SRU flare header for a short time. To reduce the emissions of sulfur compounds to the environment during SRU or TGU shutdown, the acid gas is routed to the emergency caustic scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU flare stack via the SRU flare knockout drum. Fresh and spent caustic tanks and pumps are provided to allow delivery of fresh caustic and disposal of spent caustic.

Rectisol Acid Gas Removal Flare (Rectisol Flare)

Cold reliefs and vents from the AGR Unit and its associated Refrigeration Unit, and the Ammonia Synthesis Unit are collected in the Rectisol® Flare header. The Rectisol® Flare header is used only in startup, shutdown, emergencies, or plant upsets, and contains gases that can be below the freezing point of water. For this reason, the Rectisol® Flare header gases are segregated from the wet gases in the Gasification Flare header.

Manufacturing Complex:

Pressure Swing Adsorption (PSA) Unit

A portion of clean hydrogen-rich stream from the AGR unit is sent to the PSA unit to generate a high-purity hydrogen gas stream for use as a feedstock to the Ammonia Synthesis Unit. The offgas from the PSA unit is compressed and sent to the HRSG for use as duct-burner fuel. Two PSA Units in series are used to maximize hydrogen recovery.

Ammonia Synthesis Unit (S-7616-33-0):

The high-purity hydrogen stream from the pressure swing adsorption (PSA) unit and a nitrogen stream from the Air Separation Unit are the two primary feedstocks for the Ammonia Synthesis Unit. The major steps in the process are described below.

The hydrogen and nitrogen feed streams are first compressed to a high pressure and then mixed with recycled gas in the syngas compressor (electric powered). The combined mixture is then further compressed, heated, and fed to the ammonia (NH3) synthesis converter, where the exothermic conversion to ammonia takes place over an iron-based catalyst as follows:

$$3\ H_2 + N_2 \leftrightarrow 2\ NH_3$$

The hot ammonia synthesis converter effluent is first cooled by generating steam in the waste heat boiler. The converter effluent is then further cooled in a series of exchangers to condense the ammonia product and separate it from the vapor stream in the primary separator. The vapor stream from the primary separator is recycled to the syngas compressor while the liquid ammonia product is first processed for the removal of inert substances, and then it is routed to storage.

The cold liquid ammonia storage system uses two vertical, cylindrical steel tanks, each housed in its own unique second vessel to provide double integrity containment, elevated above ground on a concrete pedestal, surrounded by a concrete barrier. A vapor recovery system is included to prevent any product losses. The tanks have sufficient storage capacity to support a cold startup of the ammonia synthesis unit. Additionally, the capacity of the tanks enables the production rate of urea pastilles and UAN solution to remain relatively constant as the IGCC plant undergoes on-peak and off-peak operations. The liquid ammonia is pumped from the tanks to the various users within the facility.

Ammonia is intended to be used on site to produce urea pastilles and UAN solution, and as the reagent for the SCR NOx emission control system.

Ammonia Startup Heater Serving Ammonia Synthesis Unit

A 56.0 MMBtu/hr natural gas-fired startup heater is provided in the ammonia synthesis unit to raise the catalyst bed temperatures during initial plant commissioning, or during startup after a plant maintenance outage.

The ammonia synthesis unit also contains two ammonia refrigeration systems: one system to provide the chilling required for cooling the converter effluent stream and the ammonia product stream; and a smaller system and to recover and condense ammonia vapor from the ammonia storage tanks.

A process flow diagram of the ammonia synthesis unit (Figure 2-29: Ammonia Synthesis Unit) is located in Appendix D.

Urea Unit with Urea Pastillation and Pastille Handling Operation (S-7616-34-0)

Urea Unit

CO_2 recovered in the AGR Unit is compressed and treated in the CO_2 Purification Unit to remove any trace sulfur compounds and produce very high-purity CO_2 for urea synthesis. Liquid ammonia from the upstream Ammonia Synthesis Unit is pumped and combined with this CO_2 stream in the Urea Reactor. The following exothermic reaction proceeds quickly:

$$2\ NH_3 + CO_2 \leftrightarrow NH_2\text{-}CO\text{-}ONH_4 \text{ (ammonium carbamate)}$$

Ammonium carbamate is then dissociated to urea and water through the application of heat. The reaction kinetics for urea production are slower than those for the ammonium carbamate reaction.

$$NH_2\text{-}CO\text{-}ONH_4 \leftrightarrow NH_2\text{-}CO\text{-}NH_2 \text{ (urea)} + H_2O$$

Because the above reaction does not proceed to completion, additional steps are necessary to produce the desired urea product. Various combinations of dissociation, condensation, recycle of unconverted reactants, and stripping are used to complete the conversion to urea.

Finally, the intermediate urea solution is concentrated to provide the required feeds to the UAN Complex and to the Urea Pastillation Unit. Vacuum evaporator/separator systems are used to produce the required urea solutions. A single stage unit can provide approximately 80 weight percent urea feed to the UAN complex, and a multistage system is required to provide more than 99 weight percent urea melt for the pastillation unit. These solutions are then pumped to the final stage in their respective production processes. Vapors from the vacuum system are scrubbed in an absorber using process condensates. The treated

vapors (inert substances) are vented. The process condensates are recycled within the Urea Unit.

The capacity of the Urea Unit is sufficient to provide the combined urea product for both downstream UAN and pastillation production requirements. An intermediate urea solution surge tank is provided to enable continuous production, should operations of either the upstream or downstream systems be briefly interrupted**.**

Process flow diagrams of the urea unit (Figure 2-30: Urea Unit – Synthesis and Figure 2-31: Urea Unit - Concentration) are located in Appendix D.

Urea Pastillation Unit and Pastille Handling

Pastillation technology converts the urea melt, which is manufactured in the urea unit, into pastilles. According to the applicant, pastillation was selected due to its ability to minimize emissions of particulate matter and ammonia. A drop-former deposits uniform droplets onto a moving belt. These droplets solidify on the belt to produce a uniform pastille product. The heat of crystallization is removed by spraying the underside of the belt with cooling water. At no point in the process does the cooling water contact the urea product. After they have cooled and solidified, the urea pastilles are removed from the belt by an oscillating scraper. The section above the moving steel belt is enclosed with a hood and vented.

The urea pastille handling system collects urea pastilles from the urea pastillation unit and conveys them to the bulk storage and truck/rail loadout facilities.

The system accomplishes the following objectives:

- Receives urea pastilles from the urea pastillation unit;
- Conveys the urea pastilles to the urea storage domes (S-7616-37-0);
- Reclaims the urea pastilles; and
- Conveys the urea pastilles to the urea loadout system (S-7616-37-0).

All conveyors are fully enclosed in tubular galleries for weather protection and for control of fugitive dust. All urea-handling buildings are fully enclosed with roofing and siding. Dust collection systems are used to control dusting and fugitive dust emissions.

Urea Ammonium Nitrate Complex:

In order to produce Urea Ammonium Nitrate (UAN) solution, it is necessary to produce several intermediate products. These include nitric acid (HNO_3), ammonium nitrate (NH_4NO_3), and urea (NH_2-CO-NH_2). The following sections provide a brief overview of each of these processes.

Nitric Acid Unit (S-7616-35-0):

Nitric acid production is a three-step process consisting of NH_3 oxidation, nitric oxide (NO) oxidation, and absorption. In the ammonia oxidation step, ammonia from the Ammonia Synthesis Unit is oxidized by air at high temperatures as it passes over a platinum-based catalyst. The exothermic oxidation reaction proceeds as shown below:

$$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$$

The hot effluent from the reactor is cooled via steam generation or cross-exchange with another process stream. Nitric oxide formed during the ammonia oxidation step must also be oxidized. In order to accomplish this, the process stream is cooled. Nitric oxide reacts non-catalytically with O_2 to form nitrogen dioxide (NO_2):

$$2\ NO + O_2 \rightarrow 2\ NO_2$$

Next, the nitrogen dioxide is further cooled and introduced into an absorption tower along with water. Nitric acid is formed via the following reaction:

$$3\ NO_2 + H_2O \rightarrow 2\ HNO_3 + NO$$

The applicant indicated that on average the nitric acid concentration is expected to be 57 percent by weight. The unit capacity of the nitric acid unit is 501 tons per day, expressed on a 100% acid basis.

An additional air stream is introduced to re-oxidize the nitric oxide formed in the above reaction. This air stream also helps to remove any dissolved nitrous oxide present from the acid product.

Tail gas from the absorber column is cleaned before being vented. Catalytic decomposition and reduction of both nitrous oxide (N_2O) and NO_X are used to control emissions. The tail gas abatement unit complies with BACT requirements.

A process flow diagram of the nitric acid unit (Figure 2-32 – Nitric Acid Unit) is located in Appendix D.

Ammonium Nitrate Unit (S-7616-36-0):

Ammonium nitrate (NH_4NO_3) solution is produced via a neutralization reaction between gaseous NH_3 and aqueous HNO_3. The exothermic reaction proceeds as follows:

$$NH_3 + HNO_3 \rightarrow NH_4NO_3$$

Ammonium nitrate is produced and stored as a liquid solution (rather than in the solid form) to enhance process safety.

The water condensed in the ammonium nitrate unit is reused in the process.

Urea Ammonium Nitrate Unit

The ammonium nitrate solution and the urea solution are metered, mixed, and cooled. Depending upon the concentration of the feedstock solutions and the desired product specifications, water may be added in as well. The final product is UAN, an aqueous UAN solution.

A process flow diagram of the ammonium nitrate unit and the UAN units (Figure 2-33: Ammonium Nitrate/UAN Units) is located in Appendix D.

UAN Solution Storage and Handling

The UAN solution is stored in tanks, and then loaded into railcars or tank trucks for shipment.

Urea Storage and Loadout System (S-7616-37-0):

Urea pastilles are stored in four 20,000-ton storage capacity urea domes that are fully enclosed with roofing and siding. All PM emissions from these sources are assumed to be $PM_{2.5}$ or smaller.

Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0):

The emergency engine powers an electrical generator. Other than emergency operation, the engine may be operated up to 50 hours per year for maintenance and testing purposes (as allowed by Rule 4702).

Two 60 Hz, 3-Phase, 2,000 kW, 0.8 PF standby diesel generators in an outdoor enclosure will be connected to the 480 V switchgear to supply emergency essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, station battery chargers, uninterruptible power supply (UPS), heat tracing, control room, and emergency exit lighting, and other critical plant loads.

Diesel-fired Emergency Engine Powering Firewater Pump (S-7616-40-0):

One approximately 600-horsepower standby diesel-driven firewater pump will be adjacent to the firewater tank. The emergency engine powers a firewater pump. Other than emergency operation, the engine may be operated up to 100 hours per year for maintenance and testing purposes (as allowed by Rule 4702).

V. Equipment Listing

S-7616-17-0 RAIL UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF COAL, INCLUDING: ENCLOSED RAIL UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH RAILCAR UNLOADING STATION, RAIL UNLOADING BIN(S), BELT FEEDER(S), RAIL UNLOADING CONVEYOR(S) ENCLOSED IN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

S-7616-18-0 TRUCK UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF PETROLEUM COKE (PETCOKE) AND/OR COAL, INCLUDING: ENCLOSED TRUCK UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH TRUCK UNLOADING STATION(S), TRUCK UNLOADING BIN(S), BELT FEEDER(S), TRUCK UNLOADING CONVEYOR(S) ENCLOSED IN AN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

S-7616-19-0 FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS; 30,000 CU FT FLUXANT SILO AND UNLOADING VENT SERVED BY A DUST COLLECTOR

S-7616-20-0 FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION INCLUDING: CRUSHER BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH SURGE BIN(S), BELT FEEDER(S), BYPASS SCREEN(S), TWO FEEDSTOCK CRUSHERS; TWO ENCLOSED PLANT FEED CONVEYORS SERVED BY BAGHOUSE DUST COLLECTOR; MILLING AND DRYING BUILDING WITH FEEDSTOCK DRYER [USING TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR LISTED ON S-7616-26] SERVED BY BAGHOUSE DUST COLLECTOR, WITH REVERSING CONVEYOR(S), DIVERTER GATE(S), AND TWO MILLING AND DRYING SILOS

S-7616-21-0 GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, RECTISOL ACID GAS REMOVAL (AGR) UNIT WITH 600,000 GALLON METHANOL STORAGE TANK SERVED BY METHANOL VENT SCRUBBER

S-7616-22-0 GASIFICATION SOLIDS MATERIAL HANDLING AND STORAGE SYSTEM INCLUDING: GASIFICATION SOLIDS UNLOADING BUNKER (STORAGE COVER WITH ROOFING AND PARTIAL SIDING) WITH DEWATERING TANK(S), STORAGE PILE(S), RECLAIM HOPPER AND GRIZZLY, BUCKET ELEVATOR FEED CONVEYOR SERVED BY DUST COLLECTOR, ENCLOSED TRANSFER CONVEYOR (TO GASIFICATION SOLIDS TRANSFER TOWER), GASIFICATION SOLIDS TRANSFER TOWER SERVED BY DUST COLLECTOR, WITH ENCLOSED LOAD-OUT FEED CONVEYOR (TO GASIFICATION SOLIDS LOAD-OUT BUILDING); AND ENCLOSED GASIFICATION SOLIDS LOAD-OUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH GASIFICATION SOLIDS LOAD-OUT SYSTEM WITH ONE TRUCK AND ONE RAIL LOAD-OUT STATION

S-7616-23-0 SULFUR RECOVERY AND TAIL GAS COMPRESSION SYSTEM CONSISTING OF SULFUR RECOVERY UNIT (SRU), A TAIL GAS UNIT (TGU) WITH A NATURAL GAS-FIRED TAIL GAS THERMAL OXIDIZER RATED UP TO 96 MMBTU/HR (OR EQUIVALENT), AND MISCELLANEOUS TANKS, COMPRESSORS, PUMPS, CONDENSERS, HEAT EXCHANGERS, PIPING

S-7616-24-0 CO2 RECOVERY (CAPTURE, COMPRESSION, AND TRANSPORTATION) AND VENT SYSTEM FOR EMERGENCY RELEASES OF A STREAM OF PRIMARILY CO2 FROM THE ACID GAS REMOVAL UNIT

S-7616-25-0 230 MMBTU/HR NATURAL GAS-FIRED AUXILIARY BOILER EQUIPPED WITH LOW-NOX BURNER WITH FLUE GAS RECIRCULATION AND SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM (OR EQUIVALENT)

S-7616-26-0 431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI M501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE, AND FEEDSTOCK DRYER VENT (USING TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR)

S-7616-27-0 MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING GASIFICATION BLOCK AND PROCESS UNITS

S-7616-28-0 MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING AIR SEPARATION UNIT

S-7616-29-0 MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING POWER BLOCK

S-7616-30-0 4,000 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.5 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING GASIFICATION BLOCK (OR EQUIVALENT)

S-7616-31-0 2,100 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)

S-7616-32-0 5,500 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING RECTISOL UNIT (OR EQUIVALENT)

S-7616-33-0 AMMONIA SYNTHESIS UNIT CONSISTING OF: ONE 56.0 MMBTU/HR NATURAL GAS-FIRED AMMONIA STARTUP HEATER EQUIPPED WITH FOUR LOW-NOX BURNERS, EACH RATED AT 14.0 MMBTU/HR (OR EQUIVALENT); AMMONIA SYNTHESIS CONVERTER; SEPARATORS; ELECTRIC SYNGAS COMPRESSOR; ELECTRIC AMMONIA REFRIGERATION COMPRESSOR; AMMONIA ACCUMULATOR; AMMONIA REFRIGERATION SYSTEM; COLD LIQUID AMMONIA STORAGE SYSTEM; AMMONIA RECOVERY UNIT

S-7616-34-0 UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS VENTED TO THE UREA ABSORBER VENT; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR

S-7616-35-0 NITRIC ACID UNIT FOR THE PRODUCTION OF NITRIC ACID FROM AMMONIA OXIDATION, NITRIC OXIDE OXIDATION, AND ABSORPTION SERVED BY: SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX, AND TERTIARY CATALYTIC DECOMPOSITION TO CONTROL N2O

S-7616-36-0 AMMONIUM NITRATE UNIT THAT PRODUCES AMMONIUM NITRATE, CONSISTING OF: NEUTRALIZER WITH INTEGRAL SCRUBBER TO CONTROL AMMONIA; PROCESS CONDENSATE TANK WITH VENT SCRUBBER TO CONTROL PARTICULATE MATTER EMISSIONS; AMMONIUM NITRATE COOLER, AND PROCESS PUMP(S)

S-7616-37-0 UREA STORAGE AND HANDLING OPERATION CONSISTING OF FOUR 20,000-TON STORAGE CAPACITY ENCLOSED UREA STORAGE DOMES EACH WITH ONE UREA TRANSFER TOWER, WITH EACH TRANSFER

TOWER SERVED BY ONE DUST COLLECTOR; ENCLOSED UREA RECLAIM BUILDING WITH RECLAIM HOPPERS AND GRIZZLIES; ENCLOSED, TUBULAR RECLAIM CONVEYOR (THAT TRANSFERS MATERIAL TO UREA TRANSFER TOWER #5); UREA TRANSFER TOWER #5 SERVED BY DUST COLLECTOR; ENCLOSED, TUBULAR LOADOUT FEED CONVEYOR (THAT TRANSFERS MATERIAL TO LOADOUT BUILDING); UREA LOADOUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH RAIL/TRUCK LOADOUT CONVEYOR, ONE TRUCK AND ONE TRAIN LOADOUT WEIGH SYSTEM, AND ONE TRUCK AND ONE TRAIN LOADING SPOUT AND VENT SYSTEM

S-7616-38-0 2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #1 (OR EQUIVALENT)

S-7616-39-0 2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #2 (OR EQUIVALENT)

S-7616-40-0 556 BHP CUMMINS MODEL CFP-15E-F40 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A FIREWATER PUMP (OR EQUIVALENT)

VI. Emission Control Technology Evaluation

Combined Cycle Power Generating System (S-7616-26-0)

Power Block Startup

The MHI M501 GAC® and the MHI steam turbine are on a common shaft, with the common generator located between the combustion turbine generator (CTG) and steam turbine generator (STG). A clutch is provided between the STG and the generator to allow the CTG to startup independently of the STG. The clutch is disengaged during the following CTG startup sequence.

Once all the startup emissions are met, the MHI M501 GAC CTG start signal is given and the generator is used as a motor to rotate the CTG and accelerate it until the operation is self-sustaining (static start). The CTG compressor is first partially loaded to provide enough air flow and duration to purge the HRSG. Following the purge, natural gas is introduced into the CTG combustors, resulting in the CTG operation becoming self-sustaining, and the discontinuation of the static start. Natural gas is required to start up the combustion turbine. When the combustion turbine reaches 3,600 revolutions per minute (rpm), or "full speed, no load," it is synchronized with the electrical grid, and the main breaker is closed. Shortly after the CTG is synchronized, it is loaded to a minimum, or "spinning reserve" load. All the preceding steps are executed automatically by the CTG's control computer system. At this point, the HRSG begins warming up and rapidly begins to produce steam. The steam is initially vented; and, as pressure builds in the steam system, the atmospheric vents close and the steam flow is diverted to the surface condenser. Once dry, superheated steam is available at the STG, the STG startup sequence can be initiated. The STG can then be accelerated to 3,600 rpm to match speed with the generator shaft. Once the speeds are synchronized, the clutch can be engaged, and both the CTG and the STG will supply shaft work to the generator. The steam turbine metal temperatures determine how quickly the steam turbine can be loaded. The cold-start sequence requires the CTG to operate at reduced load (below the emission compliance level) for up to 4.5 hours. During this time, the CTG load is slowly increased to match the steam temperature to the STG metal temperature to heat the STG while minimizing thermal stress. Once the CTG reaches the required load, steam is introduced to control NO_X formation. Once the SCR catalyst reaches the required temperature, ammonia injection is initiated, and the HRSG stack emissions will fall to the required compliance levels. The CTG can then be loaded normally to base load, and the STG will reach a load based on the available steam.

Operating Emissions

This section describes steady-state operations, and the startup/shutdown operations and associated emissions from each source at HECA. A detailed description of the sequence of actions that will be taken to bring all plant components on line during a plant-wide startup is provided in the calculations section.

Power Block CTG/HRSG

The most significant emission source of the project will be the CTG/HRSG train. The MHI M501 GAC CTG/STG generator will provide approximately 431 MW nominal gross output to produce approximately 300 MW of reliable, low-carbon baseload electricity. Exhaust gas from the turbine section is ducted through the HRSG to generate high-energy steam, which produces additional electricity in the steam turbine. Some of the exhaust gas is also ducted from the HRSG to the Gasification Block to dry the feedstock, and will be discharged at the coal-dryer stack in that process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. The combustion system is also equipped with separate fuel nozzles for natural-gas firing during startup, shutdown, and equipment outages. The combustion system is designed to achieve low-NO_X emissions while injecting nitrogen diluent and combusting hydrogen-rich fuel. When operating on natural gas, water is injected for NO_X control, in addition to SCR. Natural gas is used during startup and shutdown of the combustion turbine and during periods of unplanned equipment outages (up to 2 weeks per year).

The combustion turbine exhaust gas, supplemental hydrogen-rich fuel for duct-firing, and PSA off-gas for duct-firing are used as energy input into the HRSG. An SCR system is installed in the HRSG to reduce emissions of NO_X to meet BACT requirements. An oxidation catalyst is also installed in the HRSG to reduce CO and VOC emissions to achieve BACT levels for these pollutants. The HRSG stack is provided with a CEMS to verify compliance with applicable requirements. The CTG/HRSG will operate in a compliance load range of 70 to 100 percent.

Power Block CTG/HRSG and Feedstock Dryer Operating Emissions

During operations and some phases of the startup and shutdown activities, a portion of the HRSG flue gas will be diverted to the feedstock drying area, filtered through a baghouse, then exhausted from the coal-dryer stack. As a result, the emissions from the HRSG and coal-dryer stacks are interconnected. The HRSG flue gas that is diverted to the feedstock dryer has emissions already controlled by the oxidation catalyst and SCR. The exhaust stream through the coal-dryer stack is further controlled with a baghouse before being exhausted to the atmosphere.

Maximum short-term operational emissions from the CTG/HRSG and feedstock dryer were determined from a comparative evaluation of potential emissions corresponding to on-peak and off-peak operating conditions. The criteria pollutant emission rates were provided by the turbine vendor and the design engineers for two load conditions (on-peak and off-peak), and for each of three ambient temperatures (39 ºF, 65 ºF, and 97 ºF) when firing syngas, and one load condition (off-peak) when firing natural gas. The maximum short-term operational emissions (in lb/hr) from the CTG/HRSG and feedstock dryer when combusting syngas, and from the CTG/HRSG when operating on natural gas, are presented in Table 3-3 (Maximum Short-Term Emissions From CTG/HRSG And Feedstock Dryer Stack During On-Peak Operations), which is located in Appendix F.

The long-term operational emissions (in tons/year) from the CTG/HRSG and feedstock dryer were estimated by summing the emissions contributions from on-peak operating conditions, including duct-firing (for the average ambient condition of 65 ºF), CTG/HRSG startup/shutdown conditions, and maximum natural gas usage. These annual emissions of air pollutants for the CTG/HRSG and feedstock dryer have been calculated based on the expected operating schedule of 8,000 hours of operations, two startups and shutdowns per year, and 2 additional weeks of natural-gas operations other than startup and shutdown events.

CTG/HRSG Startup and Shutdown Emissions

Because startup and shutdown events typically have higher emission rates than normal operating conditions, they are incorporated into the short- and long-term emissions estimates for the CTG/HRSG for modeling purposes. The CTG will initially be started up using natural-gas fuel, then it will be shifted to syngas as the syngas becomes available. Conversely, during a shutdown, the CTG will be operated on syngas until production decreases, then the CTG will be operated on natural gas. Therefore, the expected emissions and durations of startup and shutdown events summarized in Table 3-5 (CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down), which is located in Appendix F.

Because hours that include startup and shutdown events will have higher NO_X, CO, and VOC emissions than the normal operating condition with fully functioning SCR and CO oxidation catalyst, these events were incorporated (as applicable) into the worst-case short- and long-term emissions estimates in the air quality dispersion modeling simulations for these pollutants.

Material Handling Dust Collection:

Railcar Unloading and Transfer System (S-7616-17-0)
Truck Unloading and Transfer System (S-7616-18-0)
Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)
Gasification Solids Material Handling System (S-7616-22-0)

Particulate matter emissions are associated with the material handling of the feedstock, petcoke and coal, urea, fluxant, and gasification solids. These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and feedstock crusher, all controlled with a system of baghouses. Coal and petcoke will be stored in a storage building with separate coal and petcoke storage piles. Fluxant will be stored in a silo with a vent controlled by a baghouse. The transfer conveyors are fully enclosed to control fugitive dust. All PM emissions from these sources are assumed to be PM2.5 or smaller.

Urea Storage and Loadout System (S-7616-37-0):

Urea pastilles are stored in four buildings that are fully enclosed with roofing and siding. All PM emissions from these sources are assumed to be $PM_{2.5}$ or smaller.

Feedstock Grinding/Crushing and Drying System (S-7616-20-0)

Feedstock Grinding and Drying

The proposed gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in intermediate storage bins. The feedstock then flows to the grinding mills, where the particle size is reduced to that required for transport into the gasifier, and simultaneously dried. The heat source for feedstock drying is hot turbine exhaust gas from the heat recovery steam generator (HRSG). After drying the feedstock, the drying gases flow through a dust collection system before being vented through the coal-dryer stack.

The grinding mill feed bins will be totally enclosed and will include baghouses to remove airborne dust. Petcoke and coal will be transported from the unloading systems to the enclosed barn, the pre-crushing system, and the grinding mill feed bins in enclosed conveyors with dust collection systems.

Feedstock Dryer

The MHI gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in silos. The feedstock then flows to the grinding mills, where the particle size is reduced to that required for transport into the gasifier and simultaneously dried. The heat source for feedstock drying is a slipstream of the hot turbine exhaust gas from the HRSG. After drying the feedstock, the drying gases flow through a dust collection system, then to the atmosphere. The dried feedstock flows to intermediate storage bins, from which it is transported into the gasifier.

Sulfur Recovery and Tail Gas Compression System (S-7616-23-0):

Acid gas from the AGR unit, sour gas streams from the two sour water strippers, and various plant vents are fed to a SRU. A portion of the H_2S in the feed is oxidized to SO_2 in a reaction furnace. The resulting SO_2 reacts with the remaining H_2S in the correct ratio to form elemental sulfur. These reactions proceed as shown below:

$$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O$$

$$2\ H_2S + SO_2 \leftrightarrow 3\ S + 2\ H_2O$$

Hot effluent gases from the reaction furnace are cooled in the waste heat boiler by generation of 600 pounds per square inch gauge (psig) steam. The tempered effluent gas is sent to the first condenser, where the temperature is decreased further to condense and recover elemental sulfur. Low-pressure steam is generated in the first condenser. Gas leaving the first condenser is then reheated before entering a catalytic reactor to further promote the H_2S and SO_2 reaction to elemental sulfur, followed by a condenser to recover additional sulfur. One additional reheater, reactor and condenser follow.

Sulfur recovered in the three condenser stages is sent to a Sulfur Degassing Unit to reduce the concentration of H_2S dissolved in the sulfur product. After degassing, the liquid sulfur product is sent to a storage tank and ultimately shipped from the facility via rail or truck.

SRU effluent gases exiting the final condenser are directed to the Tail Gas Unit (TGU) hydrogenation equipment, which converts the various sulfur compounds remaining in the gas, back to H_2S. Water is condensed out of the hydrogenated tail gas in a quench tower, after which it is compressed and recycled to the Sour Shift Unit. This configuration minimizes sulfur emissions from the facility and eliminates the need for a TGU amine section. This configuration also recovers the CO_2 that would be emitted by a conventional TGU.

The SRU will include both ammonia-destruction and O_2-enrichment technology in the reaction furnace, in addition to the degassing technology used in treatment of the product sulfur. Oxygen enrichment technology uses high-purity O_2 rather than air in the combustion section of the SRU, thereby decreasing the volumetric flow of gas through the entire unit. The use of O_2 increases the temperature in the reaction furnace to a level that destroys the ammonia present in the feed gases. Ammonia destruction technology is a critical part of the SRU design. Complete destruction of ammonia in the reaction furnace helps to prevent the potential for ammonia salts to foul downstream equipment.

Tail Gas Thermal Oxidizer

Associated with the operation of the sulfur recovery process, the project will incorporate a thermal oxidizer on the TGU. The thermal oxidizer will serve as a control device to oxidize any remaining H2S (after scrubbing) and other vent gas that is generated during startups, shutdowns, and times of non-delivery of CO2 product.

The thermal oxidizer will also be used for maintenance to dispose of sulfur bearing waste gas during intermittent post-shutdown SRU passivation. In this operation natural gas is fired in the SRU burners to oxidize and remove residual sulfur, for safety reasons, prior to opening the process equipment for major maintenance such as catalyst changeout. This operation is expected to occur no more than once per year. Finally, the TGTO will be used to safely oxidize and dispose of H2S, SO2, and sulfur vapor from the occasional "presulfiding" of tail gas hydrogenation catalyst. Presulfiding, which activates new catalyst oxide loaded in the reactor prior to normal operation, consists of recirculating steam-heated hydrogen and nitrogen through the hydrogenation catalyst. The hydrogen reacts with a layer of elemental sulfur on the fresh catalyst material to form sulfides which activate the catalyst. A purge is withdrawn from the recirculating hydrogen stream to remove H2S, SO2, and other sulfur products and direct them to the TGTO for safe disposal. This operation is expected to occur less than once per year.

In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. The thermal oxidizer operates at high temperatures, and provides sufficient residence time to ensure essentially complete destruction of reduced sulfur compounds like H2S to SO2. The thermal oxidizer fires natural gas continuously to reach and maintain the required operating temperature for proper thermal destruction. Pollutant emissions

are generated from the firing of natural gas and the periodic oxidation of vent gas during SRU startup.

CO2 Recovery and Vent System (S-7616-24-0):

Carbon Dioxide Vent

The CO2 vent stack will allow for startup and intermittent emergency venting of produced CO2 when the CO2 compression, transportation, or injection systems are unavailable. The CO2 vent will enable the project to operate, rather than be disabled, by brief periods when the CO2 injection system is unavailable, and in doing so, prevents gasifier shutdown and subsequent gasifier restart with associated emissions.

The CO2 vent exhaust stream will be nearly 100 percent CO2, with small amounts of CO, VOCs, and H2S. A summary of the maximum annual CO2 vent stack emissions is presented in the table below.

Venting durations during early and mature operations were determined based on the following types of events that could occur over any 1-year period: (A) Gasification Block cold startups; (B) unplanned outages of the CO_2 compressor; (C) unplanned outages of the CO_2 pipeline; and (D) CO_2 Off-Taker unable to accept. The scenarios shown in Table 3-13 were developed to provide a conservative estimate of the venting emissions that may be required during the early operations, and for mature operations. Safe operation of the HECA project is a key factor in considering whether to shut down the gasifier during short, unplanned CO_2 transportation system events. Shutting down the entire Gasification Block and restarting it increases the risk of upsets, and must be considered when evaluating whether to vent CO_2 or shut down the Gasification Block.

Carbon Dioxide Venting Scenarios				
Scenario for Early Operation				
	Event	**Events per yr**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)** [1]
A	Cold Gasification Block startup	2	3	6
B	CO_2 Compressor unplanned outage	4	2	8
C	CO_2 Pipeline unplanned outage	1	1	1
D	CO_2 off-taker unable to accept	2	3	6
Total Days				21
Scenario for Mature Operation				
	Event	**Events (per yr)**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)**
A	Cold Gasification Block startup	1	1	1
B	CO_2 Compressor unplanned outage	2 to 4	2	4 to 8
C	CO_2 Pipeline unplanned outage	0 to 1	1	0 to 1
D	CO_2 off-taker unable to accept	0	0	0
Total Days				5 to 10
Source: HECA, 2012.				

[1] The flow rate of CO2 during venting will vary depending on the operations at the Manufacturing Complex and Power Block. Venting is expected to occur at 50 to 85 percent of the maximum designed CO2 venting rate.

Natural-Gas Fired Auxiliary Boiler (S-7616-25-0):

The auxiliary boiler will provide steam to facilitate CTG startup and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 230 MMBtu/hour (HHV). However the heat input of the unit will be limited and maintained at or below 213 MMBtu/hour. Its emissions are based on an annual capacity factor of 25 percent maximum load operation, or 466 billion Btu per year.

The NOx emissions from this boiler will be controlled by the installation of SCR. The NOX emissions are based on 5 parts per million volumetric dry (ppmvd) at 3 percent O2 with SCR. Emissions of CO are based on an exhaust concentration of 50 ppmvd at 3 percent O2. Ammonia slip emissions are estimated based on 5 ppmvd at 3 percent O2. SO2 emissions are calculated based on the sulfur content of the natural gas. PM10, PM2.5, and VOC emissions are based on vendor-supplied emission factors.

Cooling Towers (S-7616-27-0, -28-0, and -29-0):

Power cycle heat rejection will consist of a steam surface condenser, cooling tower, and cooling water system. The heat rejection system receives exhaust steam from the low pressure (LP) steam turbine and condenses it to water for reuse. Approximately 95,500 gallons per minute (gpm) of water will be circulated in the power block cooling tower.

The ASU cooling tower is located in the ASU unit near the cooling loads. The ASU cooling tower has separate pumps and piping systems, and is operated independently of the other cooling water systems. The ASU cooling tower circulation rate is approximately 45,000 gpm.

The major heat rejection duties associated with the process cooling tower are from the CO2 compressor and the AGR refrigeration unit. Cooling water is also supplied to the Gasification, Shift, LTGC, SRU/TGU, SWS, and Manufacturing Complex, as well as other miscellaneous users. The process cooling tower is next to the power-block cooling tower. Each tower has a separate cooling-water basin, pumps, and piping system, and operates independently. The process tower circulation rate is about 163,000 gpm.

The cooling water circulates through each of the mechanical draft-cooling towers, which use electric-motor–driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged by heating the air, and through evaporation of some of the cooling water. Maximum drift, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow by use of an efficient drift eliminator.

For the Power Block and process cooling towers, circulating water could range from 3,000 to 9,000 parts per million (ppm) total dissolved solids (TDS), depending on makeup water quality and tower operation. Therefore, particulate matter 10 microns in diameter or less (PM10) emissions would vary proportionately. For emission calculation purposes, it is assumed that 9,000 ppm TDS are in the circulating cooling water. The cooling equipment in the ASU requires significantly lower dissolved solids in the circulating water than the rest of the plant; thus, a maximum of 2,000 ppm TDS is assumed in the circulating ASU cooling water.

The cooling tower total PM emissions are based on the maximum expected total dissolved solids in the cooling water, annual circulating water rate, and the use of a high-efficiency drift eliminator. It is conservatively estimated that 100 percent of the PM emitted from the cooling tower will be PM10, and 60 percent of the PM10 emissions will occur as particulate matter 2.5 microns in diameter or less ([PM2.5]; a fraction or ratio of 0.6). The basis for the ratio used is described in Response to Data Request 18 (URS, 2009b), and also in "Applicant Comments On The Preliminary Determination Of Compliance For The Hydrogen Energy California (HECA) Project (08-AFC-8)".

Flares (S-7616-30-0, -31-0, and -32-0):

During gasifier startup, unprocessed/vent gas is vented to the flaring system. The Gasification Block will operate a gasification flare to safely dispose of gases during gasifier startup and unplanned power plant upsets or equipment failures. The gasification flare may operate up to 28 hours per year for startup and shutdown events.

There will be an SRU flare installed to safely dispose of gas emissions from the AGR source during startup (after passing through a scrubber), or to oxidize gas releases during emergency or upset events. The SRU flare may combust such gas streams for up to 40 hours per year during plant startups.

The Rectisol® flare will be used to safely dispose of low-temperature gas streams during startup, shutdown, and unplanned upsets or emergency events. The Rectisol® flare may be used for off-specification CO2 during gasifier startup or shutdown events. It is expected that a maximum of 40 hours per year of flaring for this purpose would be required by this flare.

During normal operations, the three flares will have pilot flames that will operate continuously. Emissions from the flares are generated from the continual operation of the natural-gas–fired pilots, and from periodic vent gases that are oxidized during planned startups and shutdowns of the Gasification Block. The annual emissions from each flare were estimated by adding the emissions from continual combustion of the pilot gas plus the planned use during gasifier startup/shutdown events.

Ammonia Synthesis Unit with Ammonia Startup Heater (S-7616-33-0):

The high-purity hydrogen stream from the PSA Unit, and nitrogen, from the ASU, are combined in an exothermic ammonia synthesis reaction that takes place at high temperature and high pressure across an iron-based catalyst. There is a large degree of heat integration within the Ammonia Synthesis Unit, and the substantial heat of reaction is recovered and used to generate steam. Cold liquid ammonia is stored in a tank at atmospheric pressure.

There are no routine operating emissions from the Ammonia Synthesis Unit. However, a startup heater (natural gas-fired) is used to heat the catalyst during a cold start of the unit. A 56 MMBtu/hr natural gas-fired startup heater is provided in the ammonia synthesis unit to raise the catalyst-bed temperatures during initial plant commissioning, or during startup after a long

period of plant shutdown. The annual heat input for this heater is not expected to exceed 7,840 MMBtu HHV, which is equivalent to approximately 140 hours of operation at full capacity.

The heater will use a low-NOx burner to control exhaust emissions to no higher than 9 ppmvd at 3 percent O2. CO emissions are based on 50 ppmvd at 3 percent O2. PM10, PM2.5, and VOC emissions are based on vendor-supplied emission factors. SO2 emissions are calculated based on a natural gas sulfur content of 1.0 gr S/scf.

Urea Unit (S-7616-34-0)

Urea Absorber

The purified and compressed CO2 and the liquid ammonia are reacted in the Urea Unit to create a concentrated urea solution, which is pumped to the Urea Pastillation Unit. Lower-concentration urea solution is produced as a feedstock to the UAN Solution Plant. Vacuum evaporator/separator systems are used to produce the required urea solutions.

The off-gases from the urea synthesis process, consisting of inerts (CO2, nitrogen, and water) present in the CO2 feed, process air, and unreacted ammonia are cleaned before passing through the high-pressure (HP) scrubber, which operates at an elevated pressure. The off-gases are scrubbed first with process water, and second with clean, cold water. In this way, nearly all of the ammonia is scrubbed from the gas. Low pressure off-gases are cleaned in the low-pressure (LP) scrubber, which operates at close to atmospheric pressure. Here, the off-gas is scrubbed with clean, cold water to reduce the ammonia content in the vent. Both the HP and LP absorbers are vented to the single Urea Absorber stack.

The only emissions associated with the Urea Absorber are in the form of ammonia, which is reduced by the wet scrubber.

Urea Pastillation Unit

The pastillation process is used to convert the urea melt into high-quality pastilles. This process unit is enclosed with a hood, and is exhausted through a baghouse, then vented. Limited ammonia and urea dust, which are classified as PM10/PM2.5, are emitted from this source. The HECA pastillation process PM10/PM2.5 emissions will be limited to a grain loading of no more than 0.001 grain per dry standard cubic foot (gr/dscf) by the baghouse.

Nitric Acid Unit (S-7616-35-0)

Nitric Acid Unit

Nitric acid production is a three-step process consisting of ammonia oxidation, NO oxidation, and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both N2O and NOx.

The N2O emissions are treated in a system classified as tertiary reduction, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction

occurs in the nitric acid unit equipment without any catalysis, simply due to the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature, rather than a reducing agent, converts 95 percent of the remaining N2O emission to molecular nitrogen (N2) and NO. The NOx emissions (including the NO formed in the N2O converter) are then reduced in one or more SCR units, with injected ammonia as a reducing agent, as is typical for NOx control in flue gas systems. Total NOx emissions from this unit will not exceed 0.2 lb/ton of dry nitric acid, or 15 ppmvd NOx. The HECA nitric acid plant will have an ammonia slip emission limit of 10 ppm downstream of the SCR.

Ammonium Nitrate Unit (S-7616-36-0)

Ammonia and nitric acid are the feedstocks to the ammonium nitrate unit, which makes the ammonium nitrate solution. The ammonium nitrate unit vent stream contains water vapor and residual ammonium nitrate solution mist that is not removed by the demisting system. If this vent stream with mist is emitted directly to the atmosphere, the mist droplets would evaporate and result in PM emissions. These particulate emissions are substantially reduced by routing the vent stream to a water-scrubbing system before discharge to the atmosphere. This vent scrubber condenses the vapor into condensate, which then absorbs the previously entrained mist droplets. The condensate stream is either recycled to the neutralizer or mixed with cooling tower blowdown for treatment and disposal. This project will use a near-total condensing vent scrubbing system, and the scrubber vent particulate emissions will be less than 0.2 lb/hr. All PM emissions are assumed to be PM2.5 or smaller.

Urea Storage and Loadout System (S-7616-37-0):

Urea pastilles are stored in four buildings that are fully enclosed with roofing and siding. All PM emissions from these sources are assumed to be $PM_{2.5}$ or smaller.

Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0):

The emission control devices/technologies and their effect on diesel engine emissions detailed below are from *Non-catalytic NO_X Control of Stationary Diesel Engines*, by Don Koeberlein, CARB.

The turbocharger reduces the NOx emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NOx. NOx emissions are reduced by approximately 15% with this control technology.

The use of very low-sulfur diesel fuel (0.0015% by weight sulfur maximum) reduces SO_X emissions by over 99% from standard diesel fuel.

Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0):

The emission control devices/technologies and their effect on diesel engine emissions detailed below are from *Non-catalytic NO_X Control of Stationary Diesel Engines*, by Don Koeberlein, CARB.

The turbocharger reduces the NOx emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NOx. NOx emissions are reduced by approximately 15% with this control technology.

The use of very low-sulfur diesel fuel (0.0015% by weight sulfur maximum) reduces SO_X emissions by over 99% from standard diesel fuel.

Fugitive Emissions:

Fugitive emissions of VOC, CO, SO2, NH3, H2S, and trace hazardous air pollutants (HAPs) and greenhouse gases (GHGs) may occur in some areas of the facility due to leaks in the piping and components. Fugitive emissions are associated primarily with the Gasification Block and the Manufacturing Complex. A leak detection and repair (LDAR) program will be implemented in select process areas to maximize emission reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals.

Potential fugitive VOC emissions from piping components were estimated using the USEPA guidance, Protocol for Equipment Leak Emission Estimates (USEPA, 1995a). The emission factors used in the calculations are the Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors from Table 7 of the referenced USEPA guidance document.

The following process streams have been identified:

Process stream #	Description
1	Methanol
2	Syngas
3	--
4	Shifted syngas
5	Propylene
6	Sour water
7	H2S-laden methanol
8	CO2-laden methanol
9	Acid gas
10	Ammonia-laden gas
11	Sulfur
12	SRU tail gas
13	Low NH3 concentration
14	Moderate NH3 concentration
15	High NH3 concentration
16	Low CO2 concentration
17	Moderate CO2 concentration
18	High CO2 concentration
18a	CO2 product and purification compressors
18b	Urea CO2 compressor
19	NO2
20	HNO3 (Nitric acid)
21	PSA off gas
22	Lower benzene concentration
23	Higher benzene concentration

An LDAR program will be implemented on select process areas with the largest estimated toxic air contaminant (TAC) and VOC fugitive emissions. Because the fugitive emission factors were based on factors for SOCMI facilities, the LDAR program implemented at this facility will meet the NESHAPs regulations, which are traditionally used at SOCMI facilities. The applicant proposes to apply the LDAR program to the following streams #1, 5, 7 through 10, and 13 through 21. These streams were selected because they had the largest uncontrolled emission estimates for methanol, propylene, H2S, and ammonia. The following compounds were included as VOCs (not all compounds are found in the gas in each process stream): methanol, propylene, COS, and hydrogen cyanide.

Some of the process streams identified in the table above serve more than one unit, so to simplify their calculation, each stream was assessed to the one DOC unit in which the stream was most prevalent. That determination was based on Figure A16-1 (Overall Block Flow Diagram with Locations of Fugitive Emissions from Process Streams), which is located in Appendix E. Based on this, the streams were assessed to a particular DOC unit as follows:

DOC Unit	Streams
S-7616-21	#1, 2, 4 through 10, 22, 23
S-7616-23	#11 through 12
S-7616-33	#13 through 21

VII. General Calculations

A & B. Assumptions & Emission Factors:

Combined Cycle Combustion Turbine Generator (S-7616-26-0):

Assumptions:

- During normal operation of the CTG/HRSG and some phases of the startup and shutdown activities, a portion of the treated HRSG flue gas will be diverted to the feedstock drying system, filtered through a baghouse, then exhausted from the feedstock dryer stack. As a result, the emissions from the HRSG and feedstock dryer stacks are interconnected.

- The HRSG flue gas that is diverted to the feedstock dryer has already been controlled by the oxidation catalyst and SCR at the HRSG. The PM10 from the exhaust stream diverted to the feedstock dryer stack is further controlled with a baghouse before being exhausted to the atmosphere.

- Since the HRSG flue gas that is diverted to the feedstock dryer is generated at the HRSG, the potential emissions out the feedstock dryer stack will be assessed to the S-7616-26.

- The emissions out the feedstock dryer stack that were generated by the CTG/HRSG will be assessed to the CTG/HRSG (S-7616-26).

- Operation of the combined-cycle power generating system:

    - Maximum annual hours of normal operation: [2]
        - On H2-rich fuel: 8,000 hr/yr
        - On natural gas backup fuel: 336 hr/yr (equivalent to 2 weeks/yr)
    - Total number of startups per year: 2
    - Total number of shutdowns per year: 2
    - The emissions from startup and shutdown will count toward the annual emission limits. The number of startups or shutdowns per year will not be limited on DOC, but instead ongoing compliance with annual emission limit will adequately account for these emissions, which will be demonstrated with the continuous emissions monitoring system serving the operation.

[2] Firing of the turbine on natural gas backup fuel will be limited to a maximum of 5 hr/yr during startup events, 10 hr/yr during shutdown events, and 336 hr/yr of unplanned equipment outages.

  - Commissioning emissions of NOx, VOC, SOx, PM10 and PM2.5 will count towards the annual emission limits. Commissioning emissions of CO will have a separate annual limit.

- Annual potential emissions are based on annual utilization and emission rates. Daily potential emissions are based on the maximum daily emission rates.

- Maximum short-term operational emissions from the CTG/HRSG and feedstock dryer were determined from a comparative evaluation of potential emissions corresponding to on-peak and off-peak operating conditions. The criteria pollutant emission rates were provided by the turbine vendor and the design engineers for two load conditions (on-peak and off-peak), and for each of three ambient temperatures (39 ºF, 65 ºF, and 97 ºF) when firing syngas, and one load condition (off-peak) when firing natural gas. The maximum short-term operational emissions (in lb/hr) from the CTG/HRSG and feedstock dryer when combusting syngas, and from the CTG/HRSG when operating on natural gas, are presented in Table 3-3 (Maximum Short-Term Emissions from CTG/HRSG and Feedstock Dryer Stack During On-Peak Operations), which is located in Appendix F.

- The long-term operational emissions (in tons/year) from the CTG/HRSG and feedstock dryer were estimated by summing the emissions contributions from on-peak operating conditions, including duct-firing (for the average ambient condition of 65 ºF), CTG/HRSG startup/shutdown conditions, and maximum natural gas usage. These annual emissions of air pollutants for the CTG/HRSG and feedstock dryer have been calculated based on the expected operating schedule of 8,000 hours of operations, two startups and shutdowns per year, and 2 additional weeks of natural-gas operations other than startup and shutdown events. The annual emissions are presented in Table 3-4 (CTG/HRSG and Feedstock Dryer Maximum Annual Operation Emissions), which is located in Appendix F.

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emission Factors:

Emission data for the combustion turbine generator was provided to the applicant by Mitsubishi Heavy Industries (MHI) based on various operating parameters. The lb/hr emission rates indicated in the tables below are equivalent to the stated ppm values of firing on natural gas and hydrogen-rich syngas.

Maximum Hourly Emission Rates:

Maximum short-term operational emissions from the CTG/HRSG and feedstock dryer were determined from a comparative evaluation of potential emissions corresponding to on-peak and off-peak operating conditions. The criteria pollutant emission rates were provided by the turbine vendor and the design engineers for two load conditions (on-peak and off-peak), and for each of three ambient temperatures (39 ºF, 65 ºF, and 97 ºF) when firing syngas, and one load condition (off-peak) when firing natural gas.

Maximum Short-Term Emissions From CTG/HRSG And Feedstock Dryer Stack During Normal and Natural Gas Backup Operations

Pollutant	Hydrogen-Rich Fuel				Natural Gas	
	CTG/HRSG Emissions (lb/hr)	Feedstock dryer Emissions (lb/hr)	Basis	CTG/HRSG Emissions Basis (ppmv @ 15 % O2)	CTG/HRSG Emissions (lb/hr)	CTG/HRSG Emissions Basis (ppmv @ 15% O2)
NO_X	25.0	4.4	Case 1 (ON Peak, 97 °F Ambient)	2.5	34.1	4
SO_2	4.1	0.9	Case 2 (OFF Peak, 97 °F Ambient)	2 ppmv total sulfur in syngas, 10 ppmv sulfur in PSA Off-gas	4.7	12.65 ppm sulfur in natural gas
PM_{10}/ $PM_{2.5}$	12.9	1.4	Case 3 (ON Peak, 39 °F Ambient)	15 lb/hr	15.0	15 lb/hr
CO	18.3	3.2	Case 1 (ON Peak, 97 °F Ambient)	3	26.0	5
VOC	3.5	0.6	Case 1 (ON Peak, 97°F Ambient)	1	5.9	2
NH_3	18.5	3.2	Case 1 (ON Peak, 97°F Ambient)	5 ppmv ammonia slip	15.8	5 ppmv ammonia slip

Source: HECA, 2012. See Table 3.3 (Maximum Short-Term Emissions from CTG/HRSG and Feedstock Dryer Stack During On-Peak Operations) in Appendix F.

Notes:

- The emission factors in this table will be used for daily PE calculations, and the natural gas emission factors will also be used for annual PE calculations.
- Emissions include duct burner operations with syngas and PSA off-gas.
- Feedstock dryer PM emissions controlled to 0.001 gr/dscf by baghouse

CTG/HRSG and Feedstock Drying Stack Emissions During Startup and Shutdown [3]							
CTG/HRSG Startup							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5	lb/hr	2.1	67.1	**2270**	**15.0**	**65**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	**2.4**	**107.2**	1044	13.1	13
3. CTG fuel change-over, 40 percent load on syngas, startup PSA/ammonia/urea units	2	lb/hr	**2.4**	66.6	81	13	4.6
Maximum Daily Startup Emissions for CTG/HRSG Stack (lb/day)			**10.7**	**381.2**	**3385.0**	**59.7**	**67.7**
Feedstock Drying Startup							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	**0.3**	**15.1**	**147.4**	**0.9**	**1.9**
3. CTG fuel change-over, 40 percent load on syngas	2	lb/hr	**0.3**	9.4	11.5	**0.9**	0.7
Maximum Daily Startup Emissions for Feedstock dryer Stack (lb/day)			**1.2**	**49.0**	**317.8**	**24.8**	**5.2**

[3] Emission factors are based on Table 3-5 (CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down), which is located in Appendix F.

CTG/HRSG Shutdown							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea unit shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	2.4	66.6	81.0	13	4.6
2. CTG fuel change-over, 40 percent load on natural gas, gasifier depressurization	3	lb/hr	**2.7**	**122**	1191	**15.0**	15.3
3. Minimum plant load, 20 percent load on natural gas	2	lb/hr	2.1	67.1	**2270**	**15.0**	**64.8**
Maximum Daily Shutdown Emissions for CTG/HRSG Stack (lb/day)			**21.9**	**766.6**	**8437.0**	**127.0**	**193.9**
Feedstock Drying Shutdown							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea plant shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	**0.3**	**9.4**	**11.5**	**0.9**	**0.7**
Maximum Daily Shutdown Emissions for Feedstock dryer Stack (lb/day)			**1.2**	**37.6**	**46.0**	**3.6**	**2.8**

Maximum Short-Term Emission Rates from CTG/HRSG During Startup (1-hour duration)					
	NO_X (lb/hr)	SO_X (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Mass Emission Rate	107.2	2.4	15.0	2,270.0	65.0
Event Description	HRSG/STG warm-up, ramp CTG to 40% load on NG	HRSG/STG warm-up, ramp CTG to 40% load on NG	CTG ignition and synchroni-zation, 20% load on NG	CTG ignition and synchroni-zation, 20% load on NG	CTG ignition and synchroni-zation, 20% load on NG

Source: HECA, 2012. See Table 3.5 (CTG/HRSG and Coal Drying Stack Emissions During Startup and Shutdown) in Appendix F.

Notes:
- The emission factors in this table will be used for daily PE calculations.

Maximum Short-Term Emission Rates from Feedstock Dryer Stack During Startup (1-hour duration)					
	NO_X (lb/hr)	SO_X (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Mass Emission Rate	15.1	0.3	0.9	147.4	1.9

Source: HECA, 2012. See Table 3.5 (CTG/HRSG and Coal Drying Stack Emissions During Startup and Shutdown) in Appendix F.

Notes:
- The emission factors in this table will be used for daily PE calculations.
- Feedstock dryer PM emissions are controlled to 0.001 gr/dscf by baghouse.

Maximum Short-Term Emission Rates from CTG/HRSG During Shutdown (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate	122	2270	64.8	15.0	2.7
Event Description	CTG fuel change-over, 40% load on NG, gasifier depressurization	Minimum plant load, 20% load on NG	Minimum plant load, 20% load on NG	CTG fuel change-over, 40% load on NG, gasifier depressuri-zation	CTG fuel change-over, 40% load on NG, gasifier depressuri-zation

Source: HECA, 2012. See Table 3.5 (CTG/HRSG and Coal Drying Stack Emissions During Startup and Shutdown) in Appendix F.

Notes:
- The emission factors in this table will be used for daily PE calculations.

Maximum Short-Term Emission Rates from Feedstock Dryer Stack During Shutdown (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate	9.4	11.5	0.7	0.9	0.3
Source: HECA, 2012. See Table 3.5 (CTG/HRSG and Coal Drying Stack Emissions During Startup and Shutdown) in Appendix F. Notes: • The emission factors in this table will be used for daily PE calculations. • Feedstock dryer PM emissions are controlled to 0.001 gr/dscf by baghouse.					

Maximum Short-Term Emission Rates from HRSG When Firing on H2-Rich Fuel – @ Worst Case Extreme Conditions (to be used for Daily Calculations)						
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)	NH_3 (lb/hr)
Mass Emission Rate	25.0	18.3	3.5	12.9	4.1	18.5
Event Description	Case 1 (On Peak, 97 F ambient)	Case 1 (On Peak, 97 F ambient)	Case 1 (On Peak, 97 F ambient)	Case 3 (On Peak, 39 F ambient)	Case 2 (Off Peak, 97 F ambient)	Case 1 (On Peak, 97 F ambient)

Natural gas is used during startup and shutdown of the CTG and during periods of unplanned equipment outages (up to 2 weeks per year), but not during normal operations.

Maximum Short-Term Emission Rates from HRSG When Firing on Natural Gas – @ Worst Case Extreme Conditions (to be used for Daily Calculations)						
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)	NH_3 (lb/hr)
Mass Emission Rate	34.1	26.0	5.9	15.0	4.7	15.8
Emission basis	4.0 ppmv @ 15% O2	5.0 ppmv @ 15% O2	2.0 ppmv @ 15% O2	15.0 lb/hr	12.65 ppm-S in natural gas	5 ppmv, ammonia slip

Average Hourly Emission Rates:[4]

Maximum Long-Term Emission Rates from HRSG Stack When Firing on H2-Rich Fuel	
Pollutant:	**Emission Rate (lb/hr):**
NO_x @ 2.5 ppm @ 15% O2	24.9
CO @ 3.0 ppm @ 15% O2	18.2
VOC @ 1.0 ppm @ 15% O2	3.5
SO_2	4.1
PM_{10} = $PM_{2.5}$	12.8
NH_3 (@ 5.0 ppm slip)	18.4

Source: HECA, 2012. See DOC Application, p. 2 of 32 in Application Appendix D (Operational Criteria Pollutant Emissions) in Appendix F.

Notes:

- The average emission factors in this table will be used for annual PE calculations.
- Average emission rates from HRSG stack occur under normal operating conditions, with PSA off-gas and H2-rich syngas, at a 65 F ambient temperature.

Maximum Long-Term Emission Rates from Feedstock Dryer When Firing on H2-Rich Fuel	
Pollutant:	**Emission Rate (lb/hr):**
NO_x	4.2
CO	3.1
VOC	0.6
SO_2	0.7
PM_{10} = $PM_{2.5}$	1.4
NH_3	3.1

Source: HECA, 2012. See DOC Application, p. 2 of 32 in Application Appendix D (Operational Criteria Pollutant Emissions) in Appendix F.

Notes:

- The average emission factors in this table will be used for annual PE calculations.
- Average emission rates from feedstock dryer occur under normal operating conditions, with PSA off-gas and H2-rich syngas, at a 65 F ambient temperature.
- Feedstock dryer PM emissions are controlled to 0.001 gr/dscf by baghouse.

Commissioning Emissions:

The following emission rates are for commissioning on natural gas. Emission rates for commissioning on hydrogen-rich fuel are provided in a separate table that follows.

[4] The average hourly emission rates will be used for annual PE calculations. The maximum hourly emission rates will be used for daily PE calculations.

Emission Rates from CTG/HRSG Stack from Commissioning on Natural Gas						
Test Phase	**Hours of Opera-tion**	**SO_X (lb/hr)**	**NO_X (lb/hr)**	**CO (lb/hr)**	**VOC (lb/hr)**	**PM_{10} (lb/hr)**
First fire	4	2.10	67.10	**2,270.00**	**65.00**	**15.00**
Rotor run-in	12	2.10	67.08	**2,270.00**	**65.00**	**15.00**
Steam blows	168	3.10	93.20	908.00	11.70	**15.00**
Restoration	N/A	N/A	N/A	N/A	N/A	N/A
Initial steam turbine roll	24	3.10	93.21	908.00	11.71	**15.00**
NO_X tuning with water injection and initial STG loading	16	3.10	10.88	378.60	7.00	**15.00**
NO_X tuning with water injection and initial STG loading	16	**4.80**	391.19	344.50	3.80	**15.00**
Finalize NO_X control constants	40	3.10	10.90	378.60	7.00	**15.00**
Finalize NO_X control constants	40	4.00	298.05	361.50	6.08	**15.00**
Finalize NO_X control constants	96	**4.80**	**391.20**	344.50	3.80	**15.00**
GTG water wash and contractual emission and simple cycle performance testing	16	**4.80**	**391.19**	344.50	3.80	**15.00**
Install SCR and oxidation catalyst	24	4.70	34.08	26.00	5.92	**15.00**
CEMS drift and source testing	64	4.70	34.09	26.00	5.90	**15.00**
Functional testing demonstration hours (6 starts)	315	2.73	77.67	155.10	6.24	14.09
Functional testing demonstration hours (6 shutdowns)	54	2.58	89.46	942.56	21.87	**15.00**
Functional testing steady state hours	48	4.70	34.10	26.00	5.90	**15.00**
GTG water wash and preparation for performance testing	N/A	N/A	N/A	N/A	N/A	N/A
Continuous operation test	192	4.70	34.10	26.00	5.90	**15.00**
Total hours	1,129					
Source: HECA, 2012. See Table 3.7 (Duration and Criteria Pollutant Emissions of the CTG/HRSG on Natural Gas) in Appendix F.						

Based on the values in the table above, the maximum short-term emission rates from the CTG/HRSG stack for commissioning on natural gas are summarized in the table below:

Maximum Short-Term Emission Rates for Commissioning of CTG/HRSG on Natural Gas (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Emission Rates	391.2	2270.0	65.0	15.0	4.8
Event Description	Finalize NOx control constants	First fire; Rotor run-in	First fire; Rotor run-in	Various	NOx tuning with water injection and initial STG loading; and others
Source: HECA, 2012. See Table 3.7 (Duration and Criteria Pollutant Emissions of the CTG/HRSG on Natural Gas) in Appendix F.					

The following emission rates are for commissioning on hydrogen-rich fuel.

Emission Rates from CTG/HRSG Stack from Commissioning on Hydrogen-Rich Fuel						
Test Phase	**Hours of Operation**	**SO_X**	**NO_X**	**CO**	**VOC**	**PM_{10}**
		(lb/hr)	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**
GTG starts on natural gas (for 20 starts)	50	2.32	**99.04**	1289.20	23.68	13.52
GTG hold time allowance (40% load on H_2-rich fuel)	240	2.40	19.98	24.30	4.60	13.00
GTG shutdown hold at 40% load on H_2-rich fuel (for 20 shutdowns)	80	2.40	19.98	24.30	4.60	13.00
GTG fired shutdowns on natural gas (for 20 shutdowns)	100	2.48	73.68	**1,622.60**	**35.12**	**15.00**
GTG/HRSG standby operation on natural gas	120	2.70	9.76	83.37	3.70	**15.00**
Gasifier fuel turnover tuning @ 40% H_2-rich fuel	20	2.40	66.60	81.00	4.60	**15.00**
CTG NO_X tuning on H_2-rich fuel	16	2.38	66.63	81.00	4.63	**15.00**
Gasifier feedstock dryer tuning	24	2.42	66.58	81.00	4.58	**15.00**
STG gasifier/SGC steam operation tuning	20	2.40	66.60	81.00	4.60	**15.00**
Zero flare tuning	48	2.40	66.60	81.00	4.60	**15.00**
CTG NO_X tuning on H_2 rich-fuel	60	4.10	21.80	16.00	3.10	**15.00**
CTG NO_X tuning on H_2 rich-fuel	60	4.10	25.00	18.30	3.50	**15.00**
CTG load change testing	60	3.30	45.80	49.70	4.10	**15.00**
CTG trip test	36	3.31	45.81	49.69	4.11	**15.00**
GTG water wash and contractual emission and simple cycle performance testing on H_2-rich fuel	24	3.00	28.71	9.42	3.71	**15.00**
Duct burner testing on H_2-rich syngas	48	4.00	29.10	15.50	3.90	**15.00**
Duct burner testing on PSA off-gas	48	**5.00**	18.60	13.60	2.60	**15.00**
Source testing @ 100% H_2-rich syngas (duct fired, H_2-rich + PSA)	16	**5.00**	29.38	21.50	4.13	**15.00**
Source testing @ 70% H_2-rich syngas (duct fired, PSA only)	16	4.00	18.63	13.63	2.63	**15.00**
IGCC performance and operating test	96	4.50	24.00	17.60	3.40	**15.00**
Total hours	1,182					
Source: HECA, 2012. See Table 3.9 (Duration and Criteria Pollutant Emissions of the CTG/HRSG on Hydrogen Rich Fuel) in Appendix F.						

Based on the values in the table above, the maximum short-term emission rates from the CTG/HRSG stack for commissioning on hydrogen-rich fuel are summarized in the table below:

Maximum Short-Term Emission Rates for Commissioning of CTG/HRSG on Hydrogen-Rich Fuel (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Emission Rates	99.0	1622.6	35.1	15.0	5.0
Event Description	GTG starts on natural gas (for 20 starts)	GTG fired shutdowns on natural gas (for 20 shutdowns)	GTG fired shutdowns on natural gas (for 20 shutdowns)	Various	Duct burner testing on PSA off-gas; & Source testing @ 100% H2 rich syngas (duct fired, H2 rich + PSA)
Source: HECA, 2012. See Table 3.9 (Duration and Criteria Pollutant Emissions of the CTG/HRSG on Hydrogen Rich Fuel) in Appendix F.					

Railcar Unloading and Transfer System (S-7616-17-0)
Truck Unloading and Transfer System (S-7616-18-0)
Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)

- The feedstock handling and storage systems will result in PM emission from the handling of coal and petroleum coke.

- The feedstock handling and storage system includes bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and reclaim, which are served by baghouses.

- Outlet dust loading of each baghouse: 0.001 grains/scf (per supplier data, Air-Cure Inc.).

- Emissions are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse, which will be imposed as limits, as indicated in the table below.

- Particulate matter emissions from the feedstock handling systems are all highly controlled by baghouses that perform well in capturing small diameter particulate matter. Therefore, particulate matter emissions are assumed to be equal to PM10.

Railcar Unloading and Transfer System (S-7616-17-0)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr** [5]				
Rail Unloading Vent	6 avg (24 max)	5	1,560	0.001	6,500	1,526,000	20,000

Truck Unloading and Transfer System (S-7616-18-0)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr**				
Truck Unloading Vent	12 avg (24 max)	5	3,120	0.001	2,000	380,000	80,000

Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr**				
Feedstock Transfer Tower 2	12 avg (24 max)	7	4,380	0.001	8,740	1,965,000	1,500
Feedstock Transfer Tower 1	12 avg (24 max)	5	3,120	0.001	8,740	1,965,000	1,500
Fluxant Unloading Vent	24 max	1.75	2,184	0.001	240	59,000	1,500

[5] The operating schedule shown is based on annual average operations for this and the other solid material handing operations that follow. According to the applicant any equipment item or activity may be in operation 24 hr/day on a short-term basis. Therefore, daily emissions will be based on 24 hr/day, and annual emissions will be based on the average operation schedule shown.

Feedstock Grinding/Crushing and Drying System (S-7616-20-0)

- As is explained in the assumptions for the combined cycle power system above, a portion of the treated HRSG flue gas will be diverted to the feedstock dryer to dry the coal. The gas stream will be filtered through a baghouse and then exhausted from the coal-dryer stack. As a result, the emissions from the HRSG and feedstock dryer stacks are interconnected. Since the combustion emissions are generated at the CTG/HRSG (S-7616-26), they will be listed under S-7616-26.

- The feedstock grinding and drying system will result in PM emissions, which will be controlled by a baghouse.

- Outlet dust loading of each baghouse: 0.001 grains/scf (per supplier data, Air-Cure Inc.)

- PM emissions are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse, which will be imposed as limits, as indicated in the table below.

- Particulate matter emissions from the feedstock handling systems are all highly controlled by baghouses that perform well in capturing small diameter particulate matter. Therefore, particulate matter emissions are assumed to be equal to PM10.

Feedstock Grinding/Crushing and Drying System (S-7616-20-0)							
Description	Operating Capacity			Grain Loading (gr/dscf)	Maximum Process Weight of Material (ton/day)	Maximum Process Weight of Material (ton/yr)	Nominal Air Flow to Collector (acfm)
	hr/ day	day/ week	hr/yr				
Feedstock Crusher Vent	12 avg (24 max)	7	4,380	0.001	8,740	1,965,000	12,600
Feedstock Bunkers Vent	12 avg (24 max)	7	4,380	0.001	8,740	1,965,000	12,600

Gasification System (S-7616-21-0):

Gasification System Fugitive Emissions:

- The gasification system will emit fugitive emissions (VOC, CO, SOx and other non-criteria pollutants) from the components serving various streams serving the gasification system.

- As is explained in the process description section of this evaluation, fugitive emissions from the methanol tank and the components serving the following streams will be assessed to S-7616-21 as calculated in the Fugitive Emission Calculations spreadsheet in Appendix E: Stream #1 (methanol), Stream #2 (syngas), Stream #4 (shifted syngas), Stream #5

(propylene), Stream #6 (sour water), Stream #7 (H2S-laden methanol), Stream #8 (CO2-laden methanol), Stream #9 (acid gas), Stream #10 (ammonia-laden gas), Stream #22 (lower benzene concentration), and Stream #23 (higher benzene concentration).

- To control the fugitive emissions, the applicant proposes to apply a leak detection and repair (LDAR) program to the following streams for S-7616-21: streams #1, 5, 7-10, 22, and 23. These streams were selected because they had the largest uncontrolled emission estimates for methanol, propylene, H2S, and ammonia.

- The following compounds were included as VOCs (not all compounds are found in the gas in each process Stream): COS, CH3OH, C3H6, and HCN.

- Fugitive emission calculations are found in Appendix E.

Potential Fugitive Emissions for S-7616-21		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	0	0
SO_X	0.2	65
PM_{10}	0	0
CO	24.4	8,915
VOC	65.9	24,425

Gasification Solids Material Handling System (S-7616-22-0)

- The gasification solids material handling operations will result in PM emissions, which will be controlled by a baghouse.

- Outlet dust loading of each baghouse: 0.001 grains/scf (per supplier data, Air-Cure Inc.)

- PM emissions from the gasification solids storage and handling operations are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse, which will be imposed as limits, as indicated in the table below.

- Particulate matter emissions from the feedstock handling systems are all highly controlled by baghouses that perform well in capturing small diameter particulate matter. Therefore, particulate matter emissions are assumed to be equal to PM10.

Gasification Solids Material Handling System (S-7616-22-0)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr**				
Gasification Solids Bucket Elevator	24	7	8,760	0.001	1,900	317,000	3,000
Gasification Solids Transfer Tower	8 avg (24 max)	3	1,248	0.001	1,900	317,000	3,000
Gasification Solids Load-Out System	8 avg (24 max)	3	1,248	0.001	1,900	317,000	10,000

- Additionally, PM emissions will result from the gasification solids bunker and pad (emission point #25) for the following processes:
  - o Gasification solids pad - stacking
  - o Gasification solids pad - reclaim

- Average wind speed for gasification solids pad emission calculations: 7.61 mi/hr

- Moisture content for gasification solids stacking material: 12% (applicant)

- Moisture content for gasification solids reclaim material: 8% (applicant)

- Maximum material process rate of gasification solids pad stacking: 943 ton/day

- Maximum material process rate of gasification solids pad reclaim: 943 ton/day

Sulfur Recovery and Tail Gas Compression System (S-7616-23-0):

Tail Gas Thermal Oxidizer Serving Sulfur Recovery Unit (SRU):

- Thermal oxidizer firing rate (maximum natural gas consumption):
  - o 16 MMBtu/hr natural gas assist burner (normal operation to control the process vent gas) [6]
  - o additional 80 MMBtu/hr (during SRU startup for a total of 96 MMBtu/hr)

[6] During normal operations, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer to prevent nuisance odors. Although the maximum rating of the natural gas assist burner is 16 MMBtu/hr, the applicant proposes to limit its heat input to 13 MMBtu/hr.

- The thermal oxidizer can potentially operate up 8,314 hr/yr to control the process vent gas (normal operation at a maximum heat input of 13 MMBtu/hr), up to 48 hr/yr to control the SRU startup gas (as proposed by applicant), up to 24 hr/yr during SRU passivation (as proposed by applicant) and up to 24 hr/yr during presulfiding of the catalyst (as proposed by applicant).

- Only the SOx emission factors will vary depending on whether the oxidizer controls the process vent gas or the SRU startup gas. NOx, PM10, CO, and VOC emission factors will be the same under either type of operation.

- Assume an allowance of 2.0 lb-SO2/hr to account for sulfur in the various vent streams plus fuel.

- Maximum annual operation for SRU startup gas disposal:
  48 hr/yr (approximately 2 events per year at 80 MMBtu/hr)

- Maximum annual operation for SRU passivation:
  24 hr/yr (one event per year)

- Maximum annual operation for Presulfiding:
  24 hr/yr (one event per year)

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emission Factors for Tail Gas Thermal Oxidizer (for Disposal of Process Vent Gas)		
NOx (lb/MMBtu)	0.24	Applicant's Engineering Estimates (from project S-1093741)
CO (lb/MMBtu)	0.20	Applicant's Engineering Estimates (from project S-1093741)
VOC (lb/MMBtu)	0.0055	AP-42 Table 1.4.2
SO2 (lb/hr)	2.0 lb/hr [7]	Applicant's Engineering Estimates (from project S-1093741)
PM10 = PM2.5 (lb/MMBtu)	0.0076	AP-42 Table 1.4.2

[7] Assume an allowance of 2.0 lb-SO2/hr emission to account for sulfur in the various vent streams plus fuel.

Emission Factors for Tail Gas Thermal Oxidizer (for Disposal of SRU Startup Gas)		
NOx (lb/MMBtu)	0.24	Applicant's Engineering Estimates (from project S-1093741))
CO (lb/MMBtu)	0.20	Applicant's Engineering Estimates (from project S-1093741)
VOC (lb/MMBtu)	0.0055	AP-42 Table 1.4.2
SO2 (lb/MMBtu)	0.00204	Applicant's Engineering Estimates (from project S-1093741)
PM10 = PM2.5 (lb/MMBtu)	0.0076	AP-42 Table 1.4.2

Emission Factors for Tail Gas Thermal Oxidizer (for SRU Passivation)		
NOx (lb/MMBtu)	0.24	Applicant's Engineering Estimates (from project S-1093741)
CO (lb/MMBtu)	0.20	Applicant's Engineering Estimates (from project S-1093741)
VOC (lb/MMBtu)	0.0055	AP-42 Table 1.4.2
SO2 (lb/hr)	75.0 lb/hr	Applicant's Engineering Estimates
PM10 = PM2.5 (lb/MMBtu)	0.0076	AP-42 Table 1.4.2

Emission Factors for Tail Gas Thermal Oxidizer (for Presulfiding)		
NOx (lb/MMBtu)	N/A	Assist gas (natural gas) already included in annual emissions for Disposal of Process Vent Gas
CO (lb/MMBtu)	N/A	Assist gas (natural gas) already included in annual emissions for Disposal of Process Vent Gas
VOC (lb/MMBtu)	N/A	Assist gas (natural gas) already included in annual emissions for Disposal of Process Vent Gas
SO2 (lb/hr)	125.0 lb/hr	Applicant's Engineering Estimates
PM10 = PM2.5 (lb/MMBtu)	N/A	Assist gas (natural gas) already included in annual emissions for Disposal of Process Vent Gas

SRU Fugitive Emissions (S-7616-23-0):

- As with the gasification system, the SRU will also emit fugitive emissions from the components serving various streams serving the SRU.

- Fugitive emissions from the components serving the following streams are attributed to S-7616-23 as calculated in the Fugitive Emission Calculations spreadsheet in Appendix E: Stream #11 (sulfur) and Stream #12 (TGU process gas).

- Fugitive emission calculations are found in Appendix E.

Potential Fugitive Emissions for S-7616-23		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	0	0
SO_X	0.4	151
PM_{10}	0	0
CO	2.7	968
VOC	0	0

CO2 Recovery and Vent System (S-7616-24-0):

- Maximum duration of venting episodes: 24 hr/day and equivalent to cumulative 504 hr/yr (21 days with breakdown of operation explained in the table in Section VI. Emission Control Technology Evaluation)

- Maximum flowrate: Equivalent to 767,435 lb/hr (17,724 lb-mol/hr) (proposed by applicant). 504 hr/yr at the maximum flowrate is equivalent to 193,394 ton/yr

- Vent stream CO concentration limit: 1,000 ppm-CO (proposed by applicant)

- Vent stream VOC concentration limit: Short-term: 44 ppm-VOC (40 ppm methanol, 4 ppm benzene, proposed by applicant)

  Long-term: 24 ppm-VOC (20 ppm methanol, 4 ppm benzene, proposed by applicant)

- Vent stream H2S concentration limit: 10 ppm-H2S (proposed by applicant)

- Vent stream COS concentration limit: 10 ppm-COS (proposed by applicant)

- Molecular weights:
  CH4: 16.04
  CO: 28.01
  H2S: 34.08
  COS: 60.08

Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)

Assumptions:

- The auxiliary boiler will provide steam to facilitate CTG startup and for other industrial purposes.
- The unit will be fired solely on PUC-regulated natural gas.
- The maximum rating of the boiler will be limited 213 MMBtu/hour (based on the higher heating value [HHV]), although the unit chosen may have a maximum rating of 230 MMBtu/hr.
- The maximum annual heat input of the boiler will be limited to 466 billion Btu/yr (per the application).
- Natural gas heating value: 1,000 Btu/scf (for PUC-quality natural gas)
- F-Factor for natural gas: 8,578 dscf/MMBtu corrected to 60°F (40 CFR 60, Appendix B)
- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emission Factors:

Emissions are based on vendor supplied emission factors. NOx emissions are based on 5 ppmvd at 3 percent O2 with installation of ultra-low NOx combustors and flue gas recirculation. CO emissions are based on 50 ppmvd @ 3% O2. A summary of the auxiliary boiler emission factors is presented below.

Pollutant	Post-Project Emission Factors (EF2)			Source
NO_X [8]	6.0 lb-NO_X/MMscf	0.0060 lb-NO_X/MMBtu	5 ppmvd NO_X (@ 3%O_2)	Proposed by applicant (based on data submitted in S-1093741)
SO_X	2.85 lb-SO_X/MMscf	0.00285 lb-SO_X/MMBtu		District Policy APR 1720
PM10		0.005 lb-PM10/MMBtu		Applicant's data
CO	37 lb-CO/MMscf	0.037 lb-CO/MMBtu	50.8 ppmvd CO (@ 3%O_2)	Proposed by applicant (based on data submitted in S-1093741)
VOC	4 lb-VOC/MMscf	0.004 lb-VOC/MMBtu	9.5 ppmvd VOC (@ 3% O_2)	Proposed by applicant (based on data submitted in S-1093741)

Cooling Towers (S-7616-27-0, -28-0, and -29-0):

- Particulate Matter is the only criteria pollutant emitted by the cooling tower, of which PM_{10} and $PM_{2.5}$ are subsets.
- Density of water = 8.34 lb/gal = 1000 g/L
- Cooling tower drift eliminator will have a drift rate not to exceed 0.0005% (which is proposed by the applicant and shall be documented required by DOC conditions).
- Total dissolved solids (TDS) concentration shall not exceed 9,000 ppm for S-7616-27 and -29 (which is proposed by the applicant),[9] which is equivalent to 75.06 lb/1000 gallon.[10]
- TDS concentration shall not exceed 2,000 ppm for S-7616-28 (proposed by applicant), which is equivalent to 16.68 lb/1000 gallon.[11]
- The equivalent annual cooling tower circulation rate in the table below will be used to calculate the annual emissions and placed on the DOC as a limit.
- Due to the use of a drift eliminator, particulate matter emissions from the cooling towers are assumed to be equal to PM10.

[8] According to boiler manufacturers, low NOx burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the emissions factors for this unit during startup and shutdown will be assumed to be the same as the steady state emission factors shown in the table above.

[9] Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter.

[10] 9,000 ppm-TDS = (9,000/1E6)(8.34 lb/gal) = 0.07506 lb/gal = 75.06 lb/1000 gal; 9,000 ppm-TDS = 9,000/1E6)(1000 g/L) = 9 g/L

[11] 2,000 ppm-TDS = (2,000/1E6)(8.34 lb/gal) = 0.01668 lb/gal = 16.68 lb/1000 gal; 2,000 ppm-TDS = (2,000/1E6)(1000 g/L) = 2 g/L

- $PM_{2.5}$ emissions are 60% of the PM_{10} emissions.

Cooling Tower Specifications:				
	Serving Power Block and Process Units (S-7616-27)	**Serving Air Separation Unit (S-7616-28)**	**Serving Power Block (S-7616-29)**	**Source**
Cooling water (CW) circulation rate, gpm	162,582	44,876	95,000	Proposed by applicant
Annual Operating Hours	8,314	8,314	8,668	Proposed by applicant
Cooling water (CW) circulation rate, gallon/yr	81.10 billion	22.39 billion	49.41 billion	[12]
CW dissolved solids (ppm-TDS)	9,000	2,000	9,000	Proposed by applicant
Drift, fraction of circulating CW	0.0005%	0.0005%	0.0005%	Proposed/ BACT

Flares (S-7616-30-0, -31-0, and -32-0):

Assumptions and Emission Factors:

- The plant is designed to avoid flaring during steady-state operations, however flares are needed to protect the plant operators and equipment. The plant employs three pressure-relief systems and their corresponding flares (Gasification, Rectisol®, and SRU) for this purpose.

- Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment during upsets and emergencies. The flares also allow safe venting of equipment during routine startup and shutdown operations.

- Flaring will occur only during the startup and shutdown operations or during emergencies.

- All three flares are conventional elevated flares, and will be provided with natural gas assist as required.

- Since a portion of the operation will consist of planned flaring events, the flare will not be classified as an emergency flare.

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

[12] This is equivalent to the units' rated capacity and proposed annual operating hours.

- During non–startup/shutdown plant operation, the three flares will be operated in a standby mode with only emissions from the natural-gas pilot flames, with emission factors in the table below:

Emission Factors for Natural Gas-Fired Pilots for each of the Three Flares		
Pollutant	**lb/MMBtu**	**Emission Factor Source [13]**
NO_X	0.068	BACT and proposed by applicant (based on data submitted in project S-1093741)
SO_X	0.00214	0.75 grain/100 scf [14]
PM_{10}	0.003	Supplier Data (John Zink Co.) – project S-1093741
CO	0.08	Supplier Data (Callidus Technologies) –project S-1093741
VOC	0.0013	Supplier Data (John Zink Co.) – project S-1093741

Gasification Flare (S-7616-30-0):

- The gasification flare is an elevated flare with a maximum design capacity of 4,000 MMBtu/hr that will be allowed to operate up to 28 hr/yr of planned flaring for startup and shutdown events as detailed in the table below.

- The gasification flare has a 0.5 MMBtu/hr natural gas pilot that can operate up to 8,760 hr/yr.

- The gasification flare will dispose of excess gas during gasifier startup operations or during unplanned power plant upsets or equipment failures.

- Planned flaring will consist of the types of events, duration, and maximum gas flared shown in the table below.

- Syngas sent to the flare during planned flaring events is filtered, water-scrubbed, and sulfur-free.

- Flaring of untreated syngas or other streams within the plant will only occur as an emergency safety measure during unplanned plant upsets or equipment failures.

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

[13] The identified sources provided the emission factors in project S-7616/S-1093741.

[14] SOx emissions are based on a maximum sulfur content of 0.75 gr-S/100 scf (12.65 ppm-SOx in the natural gas) proposed by the applicant. (0.75 gr-S/100 dscf x 1 lb S/7000 gr x 64 lb-SOx/32 lb-S x 1 scf/1000 Btu x 1E6 Btu/MMBtu) = 0.00214 lb/MMBtu.

Planned Flaring: Startup/Shutdown Flared Gas for Gasification Flare (S-7616-30)						
	Duration of event (hr)	Events /yr	hr/yr	Maximum Gas Flared (MMBtu/hr)	Annual Gas Flared (MMBtu/yr)	
Flaring natural gas (startup)	3	2	6	2,926	17,556	Natural Gas: 21,936 MMBtu/yr[15]
Flaring unshifted syngas (startup)	2	2	4	2,386	9,544	Unshifted syngas: 9,544 MMBtu/yr
Flaring shifted syngas (startup)	5	2	10	2,413	24,130	Shifted syngas: 43,434 MMBtu/yr
Flaring shifted syngas (shutdown)	4	2	8	2,413	19,304	
Total annual hours:			28		74,914	
Total heat input (MMBtu/yr):						

Emission Factors for Gasification Flare (S-7616-30)				
	When Incinerating Natural Gas		When Incinerating Syngas or Waste Gases	
Pollutant	**lb/MMBtu**	**Emission Factor Source [16]**	**lb/MMBtu**	**Emission Factor Source**
NO_X	0.068	Supplier Data (John Zink Co.)	0.068	BACT and Supplier Data (John Zink Co.) – project S-1093741
SO_X	0.00214 [17]	0.75 grain/100 scf	0.002	Syngas emission factor
PM_{10}	0.003	Supplier Data (John Zink Co.)	0.008	Syngas emission factor
CO	0.08	Supplier Data (Callidus Technologies)	2.0 / 0.37	2.0 lb-CO/MMBtu on unshifted syngas (Supplier data – project S-1093741 – based on 98% destruction of CO in waste gas); 0.37 lb/MMBtu on shifted syngas (Supplier data from project S-1093741) [18]
VOC	0.0013	Supplier Data (John Zink Co.)	0.0015	Syngas emission factor

[15] Maximum annual natural gas flared will be limited to 21,936 MMBtu/yr, which is the sum of 17,556 MMBtu/yr from the natural gas startup gas and 4,380 MMBtu/yr from the 0.5 MMBtu/hr operating 8,760 hr/yr.

[16] The identified sources provided the emission factors in project S-7616/S-1093741.

[17] SO_X emissions are based on a maximum sulfur content of 0.75 gr-S/100 scf (12.65 ppm-SOx in the natural gas) proposed by the applicant. (0.75 gr S/100 dscf x 1 lb S/7000 gr x 64 lb SO_X/32 lb S x 1 scf/1000 Btu x 10^6 Btu/MMBtu) = 0.0021 lb/MMBtu.

[18] Scrubbed syngas entering the Sour Shift Unit is rich in CO and water. The Sour Shift Unit employs the water-gas shift (WGS) reaction to convert CO and water to CO_2 and hydrogen (as is in Process Description portion of this evaluation). Therefore, CO emissions vary depending on whether the unshifted syngas or shifted syngas is combusted in the flare.

SRU Flare (S-7616-31-0):

- The SRU flare has a maximum design flaring capacity of 2,100 MMBtu/hr, with maximum planned flaring of 36 MMBtu/hr plus a 0.3 MMBtu/hr natural gas pilot.

- The SRU flare will be used to safely flare gas streams containing sulfur during startup and shutdown, and gas streams containing sulfur during unplanned upsets or emergency events.

- The SRU flare will safely dispose of gas emissions from the AGR source during startup (after passing through a scrubber) or to oxidize gas releases during emergency or upset events.

- During cold plant startup of the gasification, AGR, and shift units, these acid gas streams will be diverted to the SRU Flare header for a short time. To reduce the emissions of sulfur compounds during SRU or TGU shutdown, the acid gas is routed to the emergency caustic scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU Flare stack via the SRU Flare KO drum. Fresh and spent caustic tanks and pumps are provided to allow delivery of fresh caustic and disposal of spent caustic.

- The SRU flare may combust gas streams for up to 40 hours per year during plant startups.

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emissions Factors for SRU Flare (S-7616-31-0)			
Pollutant	**Emission Factor (lb/MMBtu)** [19]	**Emission Rate (lb/hr)** [20]	**Emission Factor Source**
NO_X	0.068	2.4	BACT and Supplier Data (John Zink Co.) – project S-1093741
SO_X		18.4	4,600 lb/hr @ 99.6% control efficiency = 18.4 lb/hr
PM_{10}	0.003	0.11	Supplier Data (John Zink Co.) – project S-1093741
CO	0.08	2.9	Supplier Data (Callidus Technologies) – project S-1093741
VOC	0.0013	0.05	Supplier Data (John Zink Co.) – project S-1093741

Rectisol Flare (S-7616-32-0):

- The Rectisol flare will be used to safely dispose of low temperature gas streams during startup, shutdown, and unplanned upsets or emergency events.

[19] Emissions for CO, PM10, and VOC are based on factors for natural gas pilots above.
[20] Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) x 36 MMBtu/hr.

- The flare may be used for off-specification CO2 during gasifier startup or shutdown events.
- The maximum design capacity of the Rectisol flare is based on the total flow from an unlikely equipment failure event, such as a major failure in the acid gas removal unit.
- The Rectisol flare is an elevated flare with a maximum design capacity of 5,500 MMBtu/hr, and a maximum rating of 430 MMBtu/hr during planned flaring events, of waste gas plus natural gas assist flare, and 0.3 MMBtu/hr natural gas pilot.
- Total hours of operation (pilot): 8,760 hr/yr
- Total hour of planned flaring (for startup relief gas): 8 hr/day and 40 hr/yr (proposed by applicant)
- Maximum annual emissions are calculated based on 8,760 hr/yr of pilot operation and 40 hr/yr of planned flaring events.
- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emission Factors for Rectisol Flare (S-7616-32)			
Pollutant	**Emission Factor (lb/MMBtu)** [21]	**Emission Rate (lb/hr)** [22]	**Emission Factor Source**
NO_X	0.068	29.2	BACT and Supplier Data – Project S-1093741
SO_X		15.0	Proposed by applicant.
PM_{10}	0.003	1.29	Supplier Data (John Zink Co.) – Project S-1093741
CO	0.08	34.4	Supplier Data (Callidus Technologies) – Project S-1093741
VOC	0.0013	0.56	Supplier Data (John Zink Co.) – Project S-1093741

Ammonia Synthesis Unit (S-7616-33-0)

Ammonia Startup Heater

- The ammonia startup heater will be fired solely on PUC-regulated natural gas.
- The maximum rating of the heater is 56.0 MMBtu/hour, consisting of four 14 MMBtu/hour burners (based on the higher heating value [HHV]).

[21] Emissions for CO, PM10, and VOC are based on factors for natural gas pilots above.
[22] Emission Rate (lb/hr) = Emission Factor (lb/MMBtu) x 430 MMBtu/hr

- The maximum annual heat input of the heater will be limited to 7,840 MMBtu/yr (7.84 billion Btu/yr), which is equivalent to 140 hours of operation at full capacity.

- Natural gas heating value: 1,000 Btu/scf (for PUC-quality natural gas)

- F-Factor for natural gas: 8,578 dscf/MMBtu corrected to 60°F (40 CFR 60, Appendix B)

- The applicant proposes to pay an annual emission fee as allowed in Section 5.1.2 of District Rule 4320 in lieu of complying with the NOx emission limit of Section 5.2.

- Particulate matter emissions from combustion processes are in the sub-micron range. Therefore, particulate matter emissions are assumed to be equal to PM10.

Emission Factors:

The heater will use a low-NOx burner to control exhaust emissions to no higher than 9 ppmvd at 3 percent O2. CO emissions are based on 50 ppmvd at 3 percent O2. PM10, PM2.5, and VOC emissions are based on vendor-supplied emission factors. SO2 emissions are calculated based on 12.65 ppmv total sulfur in pipeline natural gas. A summary of auxiliary boiler emissions is presented below.

For this unit, post-project emission factors are listed in the table below.

Pollutant	Post-Project Emission Factors (EF2)			Source
NO_X	11.0 lb-NO_X/MMscf	0.011 lb-NO_X/MMBtu	9 ppmvd NO_X (@ 3%O_2)	Applicant's proposal
SO_X	2.85 lb-SO_X/MMscf	0.00285 lb-SO_X/MMBtu		District Policy APR 1720
PM10		0.005 lb-PM10/MMBtu		Applicant's proposal
CO	37 lb-CO/MMscf	0.037 lb-CO/MMBtu	50 ppmvd CO (@ 3%O_2)	Applicant's proposal
VOC	4 lb-VOC/MMscf	0.004 lb-VOC/MMBtu	9.5 ppmvd VOC (@ 3% O_2)	Applicant's proposal

Fertilizer Manufacturing Complex / Ammonia Synthesis Unit Fugitive Emissions:

- The ammonia synthesis unit (S-7616-33) is assessed fugitive emissions that will be emitted by the components serving various streams in the fertilizer manufacturing complex.

- Fugitive emissions from the components serving the following streams will be assessed to S-7616-33 as calculated in the Fugitive Emission Calculations spreadsheet in Appendix E: Stream #13 (low NH3 concentration), Stream #14 (moderate NH3 concentration), Stream

#15 (high NH3 concentration), Stream # 16 (low CO2 concentration), Steam #17 (moderate CO2 concentration), Stream #18 (high CO2 concentration), Stream #18a (CO2 product and purification compressors), Stream #18b (urea CO2 compressor), Stream #19 (NO2), Stream #20 (HNO3), and Stream #21 (PSA off gas).

- Fugitive emission calculations are found in Appendix E.

Potential Fugitive Emissions for S-7616-33		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	0	0
SO_X	0	0
PM_{10}	0	0
CO	0.7	245
VOC	0	0

Urea Unit, Including Urea Pastillation Unit and Pastille Handling Operation (S-7616-34)

Urea Absorber:

- The urea unit consists of one urea absorber vent, which results in ammonia emissions only, which are reduced by the wet scrubbers to the levels indicated below.
- Plant capacity: 1,720 ton/day (applicant)
- Urea absorber emission rate: 13.1 lb-NH3/hr (applicant)[23]

Urea Pastillation Unit and Pastille Handling Operation:

- The pastillation process is used to convert the urea melt into pastilles.[24]
- The urea pastille handling system collects urea pastilles from the urea pastillation unit and conveys them to the bulk storage/rail and truck loadout facility.
- The urea pastillation process unit is enclosed, served by a hood, is exhausted through a baghouse, then vented.
- The urea pastillation unit will result in ammonia and urea dust, which are classified as PM, which will be controlled by baghouses.

[23] The applicant provided manufacturer's guarantee that the combined ammonia emissions from the high- and low-pressure urea stacks will be 13.1 lb-NH3/hr.

[24] A drop-former deposits uniform droplets onto a moving belt. These droplets solidify on the belt to produce a uniform pastille product. The heat of crystallization is removed by spraying the underside of the belt with cooling water. At no point in the process does the cooling water contact the urea product. After they have cooled and solidified, the urea pastilles are removed from the belt by an oscillating scraper. The section above the moving steel belt is enclosed with a hood and vented

- Outlet dust loading of each baghouse: 0.001 grains/scf (per supplier data, Air-Cure Inc.)

- PM emissions from the urea pastillation unit are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse, which will be imposed as limits, as indicated in the table below.

- Particulate matter emissions from the solids material handling systems are highly controlled by baghouses that perform well at capturing small diameter particulate matter. Therefore, particulate matter emissions are assumed to be equal to PM10.

Urea Pastillation Unit and Pastille Handling Operation (S-7616-34)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr [25]**				
Urea Bucket Elevator	24	7	8,760	0.001	1,720	627,800	1,500

Nitric Acid Unit (S-7616-35-0)

- The nitric acid unit is equipped with selective catalytic reduction to control NOx.

- The proposed nitric acid plant will have an ammonia slip emission limit of 10 ppm downstream of the SCR. The emission factors for the nitric acid plant are the following:

Nitric Acid Unit (S-7616-35-0) [26]	
NO_X	0.20 lb/ton (15 ppmv in vent gas)
NH_3	1.0 lb-NH3/hr (10 ppm NH_3 slip downstream of the SCR)

- Nitric acid production: 501 ton/day (proposed by applicant; based on 100% acid basis)

- Annual operating hours: 8,052 hr/yr (proposed by applicant)

Ammonium Nitrate Unit (S-7616-36-0)

[25] The operating schedule shown is based on annual average operations. According to the applicant any equipment item or activity may be in operation 24 hr/day on a short-term basis. Therefore, daily emissions will be based on 24 hr/day, and annual emissions will be based on the average operation schedule shown.

[26] This is proposed by the applicant based on information provided by their equipment supplier (Weatherly). To adequately control the NO2 emissions from the nitric acid plant, sufficient ammonia must be injected into the SCR system. Thus, it is expected that the ammonia emission may be as high 1.0 lb-NH3/hr according to the vendor.

- The ammonium nitrate unit vent stream contains water vapor and residual ammonium nitrate solution mist that is not removed by the demisting system. If this vent stream with mist is emitted directly to the atmosphere, the mist droplets would evaporate and result in PM emissions. These particulate emissions are substantially reduced by routing the vent stream to a water-scrubbing system before discharge to the atmosphere.

- This vent scrubber condenses the vapor into condensate, which then absorbs the previously entrained mist droplets.

- The project will use a near-total condensing vent scrubbing system, and the scrubber vent particulate emissions will be less than 0.2 lb/hr. All PM emissions are assumed to be PM2.5 or smaller.

- PM10 emissions (from ammonia nitrate unit scrubber vent): 0.20 lb-PM10/hr [27]

- Ammonium nitrate production: 636 ton/day (proposed by applicant)

- Annual operating hours: 8,052 hr/yr (proposed by applicant)

Urea Storage and Loadout System (S-7616-37-0):

- The urea storage and handling operation will result in PM emissions from the handling of urea products, and these emissions will be controlled by a baghouse.

- Outlet dust loading of each baghouse: 0.001 grains/scf (per supplier data, Air-Cure Inc.)

- PM emissions from the urea storage and handling operation are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse, which will be imposed as limits, as indicated in the table below.

- Particulate matter emissions from the solids material handling systems are highly controlled by baghouses that perform well at capturing small diameter particulate matter. Therefore, particulate matter emissions are assumed to be equal to PM10.

[27] Emission rate is proposed by the applicant based on a vendor (Weatherly) guarantee in an email dated 7/16/12.

Urea Storage and Handling Operation (S-7616-37)							
Description	**Operating Capacity**			**Grain Loading (gr/dscf)**	**Maximum Process Weight of Material (ton/day)**	**Maximum Process Weight of Material (ton/yr)**	**Nominal Air Flow to Collector (acfm)**
	hr/ day	**day/ week**	**hr/yr [28]**				
Urea Transfer Tower 1	24	7	8,760	0.001	3,440	573,000	1,500
Urea Transfer Tower 2	24	1.75	2,190	0.001	3,440	573,000	1,500
Urea Transfer Tower 3	24	3.5	4,380	0.001	3,440	573,000	1,500
Urea Transfer Tower 4	24	1.75	2,190	0.001	3,440	573,000	1,500
Urea Transfer Tower 5	8 avg (24 max)	5	2,080	0.001	3,440	573,000	1,500
Urea Loading Vent	8 avg (24 max)	5	2,080	0.001	3,440	573,000	20,000

Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38 and -39):

- Emergency operating schedule: 24 hr/day
- Non-emergency operating schedule: 50 hr/year (per Airborne Toxic Control Measure for Stationary Compression Ignition Engines, Table 1) [29]
- Density of diesel fuel: 7.1 lb/gal
- EPA F-factor (adjusted to 60 °F): 9,051 dscf/MMBtu
- Fuel heating value: 137,000 Btu/gal
- BHP to Btu/hr conversion: 2,542.5 Btu/bhp-hr
- Thermal efficiency of engine: commonly ≈ 35%
- PM_{10} fraction of diesel exhaust: 0.96 (CARB, 1988)
- Rating of each engine: 2,922 bhp
- Sulfur content of very low-sulfur diesel: 0.0015% by weight sulfur maximum

To maximize selection flexibility, the applicant requests that the District use the applicable CARB standard in effect on the date of acquisition as defined in section 93115.4 as the emission limits for these engines. S-7616-38 and -39 will require that the applicable CARB off-road engine Tier standard be installed. Currently, interim Tier 4 standards apply, and emission

[28] The operating schedule shown is based on annual average operations. According to the applicant any equipment item or activity may be in operation 24 hr/day on a short-term basis. Therefore, daily emissions will be based on 24 hr/day, and annual emissions will be based on the average operation schedule shown.

[29] Table 1 (Summary of the Emission Standards and Operating Requirements for New Stationary Emergency Standby Diesel-Fueled CI Engines > 50 BHP) limits engines with PM emissions > 0.01 and ≤ 0.15 g-bhp to no more than 50 hr/yr of maintenance and testing.

rates will not exceed those standards. The potential emissions from the engines will be based on CARB's "Table 1. Off Road Compression - Ignition Diesel Engine Standards (NMHC + NOx/CO/PM in g/bhp hr)" for interim Tier 4 engines.

Interim Tier 4 Diesel-Fired IC Engines NO_X and VOC Estimated Emissions				
Horsepower Range (bhp)	NMHC (g/bhp-hr)	NOx (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
≥ 1027 hp	0.3	0.5	2.6	0.07

Additionally, the emission limit for SOx will be 0.0051 g/bhp-hr based on the following calculation.

$$\frac{0.000015\ lb-S}{lb-fuel}\times\frac{7.1\ lb-fuel}{gallon}\times\frac{2\ lb-SO_2}{1\ lb-S}\times\frac{1\ gal}{137{,}000\ Btu}\times\frac{1\ bhp\ input}{0.35\ bhp\ out}\times\frac{2{,}542.5\ Btu}{bhp-hr}\times\frac{453.6\ g}{lb}=0.0051\ \frac{g-SO_x}{bhp-hr}$$

Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0)

- Emergency operating schedule: 24 hr/day
- Non-emergency operating schedule: 100 hr/year (Rule 4702 and Airborne Toxic Control Measure for Stationary Compression Ignition Engines, Table 1) [30]
- Density of diesel fuel: 7.1 lb/gal
- EPA F-factor (adjusted to 60 °F): 9,051 dscf/MMBtu
- Fuel heating value: 137,000 Btu/gal
- BHP to Btu/hr conversion: 2,542.5 Btu/bhp-hr
- Thermal efficiency of engine: commonly ≈ 35%
- PM_{10} fraction of diesel exhaust: 0.96 (CARB, 1988)
- Rating of engine: 556 bhp
- Sulfur content of very low-sulfur diesel: 0.0015% by weight sulfur maximum

To maximize selection flexibility, the applicant requests that the District use the applicable CARB standard in effect on the date of acquisition as defined in section 93115.4 as the emission limits for these engines. S-7616-40 will require that the applicable CARB off-road engine Tier standard be installed. Currently, interim Tier 4 standards apply, and emission rates will not exceed those standards. The potential emissions from the engine will be based on CARB's "Table 1. Off Road Compression - Ignition Diesel Engine Standards (NMHC + NOx/CO/PM in g/bhp hr)" for interim Tier 4 engines.

[30] Table 1 (Summary of the Emission Standards and Operating Requirements for New Stationary Emergency Standby Diesel-Fueled CI Engines > 50 BHP) limits engines with PM emissions ≤ 0.01 g-bhp to no more than 100 hr/yr of maintenance and testing.

Interim Tier 4 Diesel-Fired IC Engines NO_X and VOC Estimated Emissions				
Horsepower Range (bhp)	NMHC (g/bhp-hr)	NOx (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
≥ 300 and < 600 bp	0.14	1.5	2.6	0.015

PM10 should be 0.015 for Interim Tier 4 (0.01 for Tier 4).

Additionally, the emission limit for SOx will be 0.0051 g/bhp-hr based on the following calculation.

$$\frac{0.000015\ lb-S}{lb-fuel}\times\frac{7.1\ lb-fuel}{gallon}\times\frac{2\ lb-SO_2}{1\ lb-S}\times\frac{1\ gal}{137{,}000\ Btu}\times\frac{1\ bhp\ input}{0.35\ bhp\ out}\times\frac{2{,}542.5\ Btu}{bhp-hr}\times\frac{453.6\ g}{lb}=\ 0.0051\ \frac{g-SO_x}{bhp-hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the emission units in this project are new, PE1 = 0 for all criteria pollutants.

2. Post-Project Potential to Emit (PE2)

Combustion Turbine Generator (S-7616-26-0)

a. Maximum Hourly PE

For most of the criteria pollutants, the maximum hourly emissions from the CTG/HRSG and its interrelated emissions from the feedstock dryer stack will occur during either startup or shutdown events as shown in the table below:

Maximum Emission Rates During Startup (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	107.2	2,270.0	65.0	15.0	2.4
Feedstock dryer stack	15.1	147.4	1.9	0.9	0.3

Maximum Emission Rates During Shutdown (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	122.0	2,270.0	64.8	15.0	2.7
Feedstock dryer stack	9.4	11.5	0.7	0.9	0.3

During normal operations (excluding startup and shutdown events) when firing on H2-rich fuel, the maximum hourly emissions at the CTG/HRGS and the feedstock dryer stack shall be the following:

Maximum Emission Rates During Normal Operations on H2-Rich Fuel (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	25.0	18.3	3.5	12.9	4.1
Feedstock dryer stack	4.4	3.2	0.6	1.4	0.9

Natural gas is required as a backup fuel for the combustion turbine (up to 2 weeks per year) and during startups and shutdowns. The maximum emission rate during those periods will be:

Maximum Emission Rates During Backup Natural Gas Operation (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	34.1	26.0	5.9	15.0	4.7
Feedstock dryer stack	N/A				

Commissioning

Maximum Emission Rates from CTG/HRSG when Firing on Natural Gas during Commissioning (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	391.2	2270.0	65.0	15.0	4.8
Feedstock dryer stack	N/A				

Maximum Emission Rates from CTG/HRSG when Firing on Hydrogen-Rich Fuel during Commissioning (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
CTG/HRSG stack	99.0	1622.6	35.1	15.0	5.0
Feedstock dryer stack	N/A				

b. Maximum Daily PE2

After the commissioning is completed, the maximum daily emissions from the CTG and the feedstock dryer will occur during startup or shutdown for certain pollutants and during regular operation for others. So, the multiple scenarios are shown in the tables below.

Daily Post-Project Potential to Emit (PE2) (on days without a startup or shutdown)						
	CTG/HRSG				Feedstock dryer	
	CTG/HRSG on H2-Rich Fuel		CTG/HRSG on Natural Gas		Feedstock dryer on H2-Rich Fuel	
	Short-Term Emission Rate (lb/hr)	(lb/day)	Short-Term Emission Rate (lb/hr)	(lb/day)	Short-Term Emission Rate (lb/hr)	(lb/day)
Formula		lb/hr x 24 hr/day		lb/hr x 24 hr/day		lb/hr x 24 hr/day
NO_X	25.0	**600.0**	34.1	**818.4**	4.4	**105.6**
SO_X	4.1	**98.4**	4.7	**112.8**	0.9	**21.6**
PM_{10}	12.9	**309.6**	15.0	**360.0**	1.4	**33.6**
CO	18.3	**439.2**	26.0	**624.0**	3.2	**76.8**
VOC	3.5	**84.0**	5.9	**141.6**	0.6	**14.4**
NH_3	18.5	**444.0**	15.8	**379.2**	3.2	**76.8**

CTG/HRSG and Feedstock Drying Stack Emissions During Startup and Shutdown							
CTG/HRSG Startup							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5	lb/hr	2.1	67.1	**2,270**	**15.0**	**65**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	**2.4**	**107.2**	1044	13.1	13
3. CTG fuel change-over, 40 percent load on syngas, startup PSA/ ammonia/urea units	2	lb/hr	**2.4**	66.6	81	13	4.6
Maximum Daily Startup Emissions for CTG/HRSG Stack (lb/day)			**10.7**	**381.2**	**3,385.0**	**59.7**	**67.7**
Feedstock Drying Startup							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	**0.3**	**15.1**	**147.4**	**0.9**	**1.9**
3. CTG fuel change-over, 40 percent load on syngas	2	lb/hr	**0.3**	9.4	11.5	**0.9**	0.7
Maximum Daily Startup Emissions for Feedstock Dryer Stack (lb/day)			**1.2**	**49.0**	**317.8**	**3.6**	**5.2**

CTG/HRSG Shutdown							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea unit shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	2.4	66.6	81.0	13.0	4.6
2. CTG fuel change-over, 40 percent load on natural gas, gasifier depressurization	3	lb/hr	**2.7**	**122.0**	1,191.0	**15.0**	15.3
3. Minimum plant load, 20 percent load on natural gas	2	lb/hr	2.1	67.1	**2,270.0**	**15.0**	**64.8**
Maximum Daily Shutdown Emissions for CTG/HRSG Stack (lb/day)			**21.9**	**766.6**	**8,437.0**	**127.0**	**193.9**
Feedstock Drying Shutdown							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea plant shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	**0.3**	**9.4**	**11.5**	**0.9**	**0.7**
Maximum Daily Shutdown Emissions for Feedstock Dryer Stack (lb/day)			**1.2**	**37.6**	**46.0**	**3.6**	**2.8**

c. Maximum Annual PE2

The maximum annual emissions from the HRSG/CTG stack are based on 8,000 hr/yr of firing on H2-rich syngas, 336 hr/yr (equivalent to 2 weeks/year) firing on natural gas (other than startup and shutdown events), two startup events, and two shutdown events. The post-project potential to emit is summarized in the table below:

Annual Post-Project Potential to Emit (PE2) from CTG/HRSG									
	Average Emissions Rate from HRSG Stack on H2-Rich Syngas (lb/hr)	HRSG Stack Emissions on H2-Rich Syngas (lb/yr)	Average Emissions Rate from HRSG Stack on Natural Gas (lb/hr)	HRSG Stack Emissions on Natural Gas (lb/yr)	Startup Emissions Rate (lb/event)	Startup Emissions (lb/yr)	Shutdown Emissions Rate (lb/event)	Shutdown Emissions (lb/yr)	Annual PE2 (lb/yr)
Formula		lb/hr x 8000 hr/yr		lb/hr x 336 hr/yr		lb/event x 2 event/yr		lb/event x 2 event/yr	Total of all events
NO_X	24.9	199,200	34.1	11,457.6	381.2	762.4	766.6	1533.2	212,953
SO_X	4.1	32,800	4.7	1,579.2	10.8	21.5	21.9	43.8	34,445
PM_{10}	12.8	102,400	15.0	5,040.0	59.7	119.4	127.0	254.0	107,813
CO	18.2	145,600	26.0	8,736.0	3385.0	6770.0	8437.0	16874.0	177,980
VOC	3.5	28,000	5.9	1,982.4	67.7	135.4	193.9	387.8	30,506
NH_3	18.4	147,200	15.8	5,308.8	0	0	0	0	152,509

Annual Post-Project Potential to Emit (PE2) from Feedstock Dryer							
	Average Emissions Rate from Coal on H2-Rich Syngas (lb/hr)	Feedstock dryer Stack Emissions on H2-Rich Syngas (lb/yr)	Startup Emissions Rate (lb/event)	Startup Emissions (lb/yr)	Shutdown Emissions Rate (lb/event)	Shutdown Emissions (lb/yr)	Annual PE2 (lb/yr)
Formula		lb/hr x 8000 hr/yr		lb/event x 2 event/yr		lb/event x 2 event/yr	Total of all events
NO_X	4.2	33,600	49.0	98.0	37.6	75.2	33,773
SO_X	0.7	5,600	1.2	2.4	1.2	2.4	5,605
PM_{10}	1.4	11,200	24.8	49.6	3.6	7.2	11,257
CO	3.1	24,800	317.8	635.6	46.0	92.0	25,528
VOC	0.6	4,800	5.2	10.4	2.8	5.6	4,816
NH_3	3.1	24,800	0	0	0	0	24,800

Railcar Unloading and Transfer System (S-7616-17-0)

Emissions are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse. Below is a sample calculation:

Daily emissions = (Air Flow to Collector)(Grain Loading)
= (20,000 ft3/min)(24 hr x 60 min/hr)(0.001 gr/dscf)(lb/7,000 gr)
= 4.11 lb-PM10/day

Daily PE2 for S-7616-17-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
Rail Unloading Vent	6 avg (24 max)	0.001	20,000	4.1
Total Emissions (lb-PM10/day)				4.1

Annual emissions = (Air Flow to Collector)(Grain Loading)
= (20,000 ft3/min)(1560 hr x 60 min/hr)(0.001 gr/dscf)(lb/7,000 gr)
= 267.4 lb-PM10/yr

Annual PE2 for S-7616-17-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Rail Unloading Vent	1,560	0.001	20,000	267
Total Emissions (lb-PM10/yr)				267

Truck Unloading and Transfer System (S-7616-18-0)

Daily PE2 for S-7616-18-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
Truck Unloading Vent	12 avg (24 max)	0.001	80,000	16.5
Total Emissions (lb-PM10/day)				16.5

Annual PE2 for S-7616-18-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Truck Unloading Vent	3,120	0.001	80,000	2,140
Total Emissions (lb-PM10/yr)				2,140

Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)

Daily PE2 for S-7616-19-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
Feedstock Transfer Tower 2	12 avg (24 max)	0.001	1,500	0.3
Feedstock Transfer Tower 1	5 avg (24 max)	0.001	1,500	0.3
Fluxant Unloading Vent	24 max	0.001	1,500	0.3
Total Emissions (lb-PM10/day)				0.9

Annual PE2 for S-7616-19-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Feedstock Transfer Tower 2	4,380	0.001	1,500	56.3
Feedstock Transfer Tower 1	3,120	0.001	1,500	40.1
Fluxant Unloading Vent	2,184	0.001	1,500	28.1
Total Emissions (lb-PM10/yr)				125

Feedstock Grinding/Crushing and Drying System (S-7616-20-0)

Daily PE2 for S-7616-20-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
Feedstock Bunkers Vent	12 avg (24 max)	0.001	12,600	2.6
Feedstock Crusher Vent	12 avg (24 max)	0.001	12,600	2.6
Total Emissions (lb-PM10/day)				5.2

Annual PE2 for S-7616-20-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Feedstock Bunkers Vent	4,380	0.001	12,600	473
Feedstock Crusher Vent	4,380	0.001	12,600	473
Total Emissions (lb-PM10/yr)				946

Gasification System (S-7616-21-0)

The gasification system has potential fugitive emissions from the methanol tank and the process streams serving the gasification system components.

The table below summarizes the emissions which were calculated in the Fugitive Emission Calculations spreadsheet in Appendix E.

Potential Fugitive Emissions for S-7616-21		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	0	0
SO_X	0.1	65
PM_{10}	0	0
CO	24.4	8,915
VOC	65.9	24,036

Gasification Solids Material Handling System (S-7616-22-0)

Daily PE2 for S-7616-22-0					
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**	**Daily Emissions (lb-PM2.5/day)**
Gasification Solids Bucket Elevator	24	0.001	3,000	0.6	0.6
Gasification Solids Transfer Tower	8 avg (24 max)	0.001	3,000	0.6	0.6
Gasification Solids Load-Out System	8 avg (24 max)	0.001	10,000	2.1	2.1
Gasification Solids Pad - Stacking	(See Calculations below.)			0.15	0.02
Gasification Solids Pad - Reclaim				0.26	0.04
Total Emissions (lb-PM10/day)				3.7	3.4

Annual PE2 for S-7616-22-0					
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**	**Annual Emissions (lb-PM2.5/yr)**
Gasification Solids Bucket Elevator	8,760	0.001	3,000	225.3	225.3
Gasification Solids Transfer Tower	1,248	0.001	3,000	32.1	32.1
Gasification Solids Load-Out System	1,248	0.001	10,000	107.0	107.0
Gasification Solids Pad - Stacking	(See Calculations below.)			54.1	8.2
Gasification Solids Pad - Reclaim				95.7	14.5
Total Emissions (lb-PM10/yr)				514	387

Fugitive particulate emissions from the gasification solids handling on the drying pad are calculated using the following formula from U.S. EPA AP-42 Section 13.2.4.3:

$E = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$

where:

E = emission factor, lb/ton
K = constant (0.35 for PM10, 0.053 for PM2.5)
U = wind speed, mph (7.61 for outdoors at the project site)
M = material moisture content, wt % (12% for solids stacking; 8% for solids reclaim)

Solids stacking:

$E(PM10) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$
$= 0.35(0.0032)(7.61/5)^{1.3}/(12/2)^{1.4}$
$= 0.000157$ lb-PM10/ton

$E(PM2.5) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$
$= 0.053(0.0032)(7.61/5)^{1.3}/(12/2)^{1.4}$
$= 0.0000238$ lb-PM10/ton

PE(PM10), solids stacking = (0.000157 lb-PM10/ton)(39.3 ton/hr)(24 hr/day)
= 0.15 lb-PM10/day
= (0.15 lb-PM10/day)(365 day/yr) = 54.1 lb-PM10/yr

PE(PM2.5), solids stacking = (0.0000238 lb-PM2.5/ton)(39.3 ton/hr)(24 hr/day)
= 0.02 lb-PM2.5/day
= (0.02 lb-PM2.5/day)(365 day/yr) = 8.2 lb-PM2.5/yr

Solids reclaim:

$E(PM10) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$
$= 0.35(0.0032)(7.61/5)^{1.3}/(8/2)^{1.4}$
$= 0.000278$ lb-PM10/ton

$E(PM2.5) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$
$= 0.053(0.0032)(7.61/5)^{1.3}/(8/2)^{1.4}$
$= 0.000042$ lb-PM2.5/ton

PE(PM10), solids reclaim = (0.000278 lb-PM10/ton)(39.3 ton/hr)(24 hr/day)
= 0.26 lb-PM10/day
= (0.26 lb-PM10/day)(365 day/yr) = 95.7 lb-PM10/yr

PE(PM2.5), solids reclaim = (0.000042 lb-PM2.5/ton)(39.3 ton/hr)(24 hr/day)
= 0.04 lb-PM2.5/day
= (0.04 lb-PM2.5/day)(365 day/yr) = 14.5 lb-PM2.5/yr

Sulfur Recovery System's Tail Gas Thermal Oxidizer (S-7616-23-0)

Pollutant	Daily PE2 (S-7616-23-0)																
	Process Vent Disposal in TGTO				SRU Startup Disposal in TGTO				SRU Passivation in TGTO				Presulfiding			SRU Fugitives (lb/day)[31]	Daily PE2 (lb/day)[32]
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)[33]	Ops (hr/day)	Daily PE2 (lb/day)	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Ops (hr/day)	Daily PE2 (lb/day)	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Ops (hr/day)	Daily PE2 (lb/day)	EF2 (lb/hr)	Ops (hr/day)	Daily PE2 (lb/day)		
NO_X	0.24	13	24	74.9	0.24	80	24	460.8	0.24	80	24	460.8	-	-	-	0.0	996.5
SO_X	2.0 lb/hr		24	48.0	0.00204	80	24	3.9	75 lb/hr		24	1800	125 lb/hr	24	3,000	0.4	4851.9 + 0.4 = 4852.3
PM_{10}	0.0076	13	24	2.4	0.0076	80	24	14.6	0.0076	80	24	14.6	-	-	-	0.0	31.6
CO	0.20	13	24	62.4	0.20	80	24	384.0	0.20	80	24	384	-	-	-	2.7	833.1
VOC	0.0055	13	24	1.7	0.0055	80	24	10.6	0.0055	80	24	10.6	-	-	-	0.0	22.8

[31] Fugitive emissions from the components serving the following streams are attributed to S-7616-23: ammonia-laden gas, sulfur, tail gas unit process gas. Fugitive emission calculations are found in Appendix C.

[32] The maximum daily PE2 for S-7616-23 will be the sum of the fugitive emissions and the highest of the Process Vent Disposal, the SRU Startup Disposal, SRU Passivation or Presulfiding emissions.

[33] Although the natural gas assist burner has a maximum rating of 16 MMBtu/hr, the applicant proposes to limit the heat input rating to 13 MMBtu/hr during normal operation.

Pollutant	Annual PE2 (S-7616-23-0)																
	Process Vent Disposal in TGTO				SRU Startup Disposal in TGTO				SRU Passivation in TGTO					Presulfiding		SRU Fugitive Emissions (lb/yr)	Annual PE2 (lb/yr)[34]
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Ops (hr/yr)	Annual PE2 (lb/yr)	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Ops (hr/yr)	Annual PE2 (lb/yr)	EF2 (lb/ MMBtu)	Heat Input (MMBtu/ hr)	Ops (hr/yr)	Annual PE2 (lb/yr)	EF2 (lb/yr)	Ops (hr/yr)	Annual PE2 (lb/yr)		
NO_X	0.24	13	8314	25,940	0.24	80	48	922	0.24	80	24	460.8	-	-	-	0	27,322
SO_X	2.0 lb/hr		8314	16,628	0.00204	80	48	8	75 lb/hr		24	1800	125 lb/hr	24	3,000	151	21,436 + 151 = 21,587
PM_{10}	0.0076	13	8314	821	0.0076	80	48	29	0.0076	80	24	14.6	-	-	-	0	865
CO	0.20	13	8314	21,616	0.20	80	48	768	0.20	80	24	384	-	-	-	968	23,736
VOC	0.0055	13	8314	594	0.0055	80	48	21	0.0055	80	24	10.6	-	-	-	0	626

[34] The maximum annual PE2 for S-7616-23 will be the sum of the fugitive emissions, the Process Vent Disposal, and the SRU Startup Disposal emissions.

CO2 Recovery and Vent System (S-7616-24-0)

Daily VOC Potential Emissions

$PE2_{VOC\ (methanol)}$ = (40 scf-VOC/1E6 scf)(lb-mol-VOC/379.5 scf-VOC)(32 lb-VOC/lbmol-VOC)(379.5 scf/lbmol)(17,724 lbmol/hr)(24 hr/day)
= 544.5 lb-VOC/day = 22.7 lb-VOC/hr (methanol basis)

$PE2_{VOC\ (benzene)}$ = (4 scf-VOC/1E6 scf)(lb-mol-VOC/379.5 scf-VOC)(78 lb-VOC/lbmol-VOC)(379.5 scf/lbmol)(17,724 lbmol/hr)(24 hr/day)
= 132.7 lb-VOC/day = 5.5 lb-VOC/hr (benzene basis)

$PE2_{VOC\ (total)}$ = 22.7 + 5.5 lb-VOC/hr = 28.2 lb-VOC/hr
= 544.5 +132.7 lb-VOC/day = 677.2 lb-VOC/day

Annual VOC Potential Emissions:

$PE2_{VOC\ (methanol)}$ = (20 scf-VOC/1E6 scf)(lbmol-VOC/379.5 scf-VOC)(32 lb-VOC/lbmol-VOC)(379.5 scf/lbmol)(17,724 lbmol/hr)(504 hr/yr)(0.85 [35])
= 4,859 lb-VOC/yr = 2.4 tons-VOC/yr (methanol basis)

$PE2_{VOC\ (benzene)}$ = (4 scf-VOC/1E6 scf)(lbmol-VOC/379.5 scf-VOC)(78 lb-VOC/lbmol-VOC)(379.5 scf/lbmol)(17,724 lbmol/hr)(504 hr/yr)
= 2,787 lb-VOC/yr = 1.39 tons-VOC/yr (benzene basis)

$PE2_{VOC\ (total)}$ = 4,859+2,787 lb-VOC/yr = 7,646 lb-VOC/yr = 3.82 tons-VOC/yr

Other Potential Emissions:

$PE2_{CO}$ = (1,000 scf-CO/1E6 scf)(lbmol-CO/379.5 scf-CO)(28 lb-CO/lbmol-CO)(379.5 scf/lbmol)(17,724 lbmol/hr)(24 hr/day)
= 11,910.5 lb-CO/day = 496.3 lb-CO/hr

$PE2_{CO}$ = (1,000 scf-CO/1E6 scf)(lbmol-CO/379.5 scf-CO)(28 lb-CO/lbmol-CO)(379.5 scf/lbmol)(17,724 lbmol/hr)(504 hr/yr)
= 250,121 lb-CO/yr = 125.1 tons-CO/yr

$PE2_{H2S}$ = (10 scf-H2S/1E6 scf)(lbmol-H2S/379.5 scf-H2S)(34 lb-H2S/lbmol-H2S)(379.5 scf/lbmol)(17,724 lbmol/hr)(24 hr/day)
= 144.6 lb-H2S/day = 6.0 lb-H2S/hr

[35] The applicant indicates that if long-term venting is occurring, the vent rate can be reduced to as low as 70 percent of maximum capacity by shutdown down some of the facility equipment. Thus, the applicant indicates that an 85 percent factor (the average of 70 and 100 percent) is realistic for long-term venting. The applicant demonstrate compliance with the annual PE for VOCs calculated.

$PE2_{H2S}$ = (10 scf-H2S/1E6 scf)(lbmol-H2S /379.5 scf-H2S)(34 lb-H2S/lbmol-H2S)(379.5 scf/lbmol)(17,724 lbmol/hr)(504 hr/yr)
= 3,037 lb-H2S/yr = 1.5 tons-H2S/yr

$PE2_{COS}$ = (10 scf-H2S/1E6 scf)(lbmol-COS/379.5 scf-COS)(60.08 lb-COS/lbmol-COS)(379.5 scf/lbmol)(17,724 lbmol/hr)(24 hr/day)
= 255.6 lb-COS/day = 10.6 lb-COS/hr

$PE2_{COS}$ = (10 scf-H2S/1E6 scf)(lbmol-COS /379.5 scf-COS)(60.08 lb-COS/lbmol-H2S)(379.5 scf/lbmol)(17,724 lbmol/hr)(504 hr/yr)
= 5,367 lb-H2S/yr = 2.7 tons-H2S/yr

Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)

The PE2 for each pollutant is calculated with the following equation:

PE2 = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Operating Schedule (hr/day or hr/year)

Pollutant	Daily PE2 for S-7616-25-0			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/day)	Daily PE2 (lb/day)
NO_X	0.006	213	24	30.7
SO_X	0.00285	213	24	14.6
PM_{10}	0.0050	213	24	25.6
CO	0.037	213	24	189.1
VOC	0.0040	213	24	20.4

Pollutant	Annual PE2 for S-7616-25-0		
	EF2 (lb/MMBtu)	Annual Heat Input Limit (billion Btu/hr)	Annual PE2 (lb/year)
NO_X	0.006	466	2,796
SO_X	0.00285	466	1,328
PM_{10}	0.0050	466	2,330
CO	0.037	466	17,242
VOC	0.0040	466	1,864

Cooling Towers (S-7616-27-0, -28-0, and -29-0):

Cooling Tower Serving Gasification Block and Process Units (S-7616-27-0)

PE_{PM10} = Drift rate x TDS (lb/gallon) x Water throughput (gal/min) x 60 min/hr x 24 hr/day
PE_{PM10} = (0.000005)(75.06 lb/1000 gallon)(162,582 gal/min)(60 min/hr)(24 hr/day)
= 87.9 lb-PM10/day
PE_{PM10} = (0.000005)(75.06 lb/1000 gallon)(162,582 gal/min)(60 min/hr)(8,314 hr/yr)
= 30,438 lb-PM10/yr

$PE_{PM2.5}$ = (87.9 lb-PM10/day)(0.6 PM2.5/PM10)
= 52.7 lb-PM2.5/day
$PE_{PM2.5}$ = (30,438 lb-PM10/yr)(0.6 PM2.5/PM10)
= 18,248 lb-PM2.5/yr

Cooling Tower Serving Air Separation Unit (S-7616-28-0)

PE_{PM10} = Drift rate x TDS (lb/gallon) x Water throughput (gal/min) x 60 min/hr x 24 hr/day
PE_{PM10} = (0.000005)(16.68 lb/1000 gallon)(44,876 gal/min)(60 min/hr)(24 hr/day)
= 5.4 lb-PM10/day

PE_{PM10} = (0.000005)(16.68 lb/1000 gallon)(44,876 gal/min)(60 min/hr)(8,314 hr/yr)
= 1,867 lb-PM10/yr

$PE_{PM2.5}$ = (5.4 lb-PM10/day)(0.6 PM2.5/PM10)
= 3.2 lb-PM2.5/day

$PE_{PM2.5}$ = (1,867 lb-PM10/yr)(0.6 PM2.5/PM10)
= 1,120 lb-PM2.5/yr

Cooling Tower Serving Power Block (S-7616-29-0)

PE_{PM10} = Drift rate x TDS (lb/gallon) x Water throughput (gal/min) x 60 min/hr x 24 hr/day
PE_{PM10} = (0.000005)(75.06 lb/1000 gallon)(95,500 gal/min)(60 min/hr)(24 hr/day)
= 51.6 lb-PM10/day

PE_{PM10} = (0.000005)(75.06 lb/1000 gallon)(95,500 gal/min)(60 min/hr)(8,668 hr/yr)
= 18,640 lb-PM10/yr

$PE_{PM2.5}$ = (51.6 lb-PM10/day)(0.6 PM2.5/PM10)
= 30.9 lb-PM2.5/day
$PE_{PM2.5}$ = (18,640 lb-PM10/yr)(0.6 PM2.5/PM10)
= 11,175 lb-PM2.5/yr

Flares (S-7616-30-0, -31-0, and -32-0)

4,000 MMBtu/hr Gasification Flare (S-7616-30-0):

Gasification Flare (S-7616-30-0) - Daily Potential Emissions											
	0.5 MMBtu/hr Natural Gas Pilot		**Flaring Natural Gas (Startup)**		**Flaring Unshifted Syngas (Startup)**		**Flaring Shifted Syngas (Startup)**		**Flaring Shifted Syngas (Shutdown)**		**Total Daily Emissions (lb/day)**
Incineration rate (MMBtu/day):	(0.5 MMBtu/hr) (24 hr/day)	12.0	(3 hr/ day)(2,926 MMBtu/hr) =	8,778	(2 hr/ day)(2,386 MMBtu/hr) =	4,772	(5 hr/ day)(2,413 MMBtu/hr) =	12,065	(4 hr/ day)(2,413 MMBtu/hr) =	9,652	
Pollutant	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day)	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day)	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day) *	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day) *	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day)	
NO_X	0.068	0.82	0.068	596.9	0.068	324.5	0.068	820.4	0.068	656.3	2,399.0
SO_X	0.00214	0.03	0.00214	18.8	0.002	11.0	0.002	27.7	0.002	22.2	79.7
PM_{10}	0.003	0.04	0.003	26.3	0.008	38.2	0.008	96.5	0.008	77.2	238.2
CO	0.08	0.96	0.08	702.2	2	9544.0	0.37	4464.1	0.37	3571.2	18,282.5
VOC	0.0013	0.02	0.0013	11.4	0.0015	7.2	0.0015	18.1	0.0015	14.5	51.2

Gasification Flare (S-7616-30-0) - Annual Potential Emissions											
	0.5 MMBtu/hr Natural Gas Pilot		**Flaring Natural Gas (Startup)**		**Flaring Unshifted Syngas (Startup)**		**Flaring Shifted Syngas (Startup)**		**Flaring Shifted Syngas (Shutdown)**		**Total Annual Emissions (lb/yr)**
Incineration rate (MMBtu/yr):	(0.5 MMBtu/hr)(876 0 hr/yr) =	4,380	(3 hr) (2,926 MMBtu/hr)(2 /yr) =	17,556	(2 hr) (2,386 MMBtu/hr)(2 /yr) =	9,544	(5 hr) (2,413 MMBtu/hr) (2 /yr) =	24,130	(4 hr) (2,413 MMBtu/hr)(2 /yr) =	19,304	
Pollutant	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr)	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr)	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr)	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr)	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr))	
NO_X	0.068	298	0.068	1194	0.068	649	0.068	1641	0.068	1313	5,094
SO_X	0.00214	9	0.00214	38	0.002	22.0	0.002	55.4	0.002	44.4	169
PM_{10}	0.003	13	0.003	53	0.008	76.4	0.008	193.0	0.008	154.4	490
CO	0.08	350	0.08	1404	2	19,088	0.37	8928	0.37	7142	36,913
VOC	0.0013	6	0.0013	23	0.0015	14.4	0.0015	36.2	0.0015	29.0	109

SRU Flare (S-7616-31-0):

SRU Flare (S-7616-31-0) - Daily Potential Emissions					
Pollutant	**From 0.3 MMBtu/hr Pilot**		**From SRU Flare Operation**		**Maximum Emissions (lb/day)**
	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day)	Emission Factor (lb/hr)	Daily Emissions (lb/day) based on 24 hr/day and 36 MMBtu/hr planned flaring limit	Total
NO_X	0.068	0.5	2.4	58.8	59.3
SO_X	0.00214	0.02	18.4	441.6	441.6
PM_{10}	0.003	0.02	0.11	2.6	2.6
CO	0.08	0.6	2.9	69.6	70.2
VOC	0.0013	0.009	0.05	1.2	1.2

SRU Flare (S-7616-31-0) – Annual Potential Emissions					
Pollutant	**From 0.3 MMBtu/hr Pilot**		**From SRU Flare Operation**		**Maximum Emissions (lb/yr)**
	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr) based on 8760 hr/yr	Emission Factor (lb/hr)	Annual Emissions (lb/yr) based on 40 hr/yr and 36 MMBtu/hr planned flaring limit	Total
NO_X	0.068	179	2.4	98	277
SO_X	0.00214	6	18.4	736	742
PM_{10}	0.003	8	0.11	4	12
CO	0.08	210	2.9	116	326
VOC	0.0013	3	0.05	2	5

Rectisol Flare (S-7616-32-0):

Rectisol Flare (S-7616-32-0) - Daily Potential Emissions					
Pollutant	**From 0.3 MMBtu/hr Pilot**		**From Rectisol Flare Operation**		**Maximum Emissions (lb/day)**
	Emission Factor (lb/MMBtu)	Daily Emissions (lb/day)	Emission Factor (lb/hr)	Daily Emissions (lb/day) based on 8 hr/day and 430 MMBtu/hr planned flaring limit	Total (lb/day)
NO_X	0.068	0.5	29.2	233.6	234.1
SO_X	0.00214	0.02	15.0	120	120.0
PM_{10}	0.003	0.02	1.29	10.3	10.3
CO	0.08	0.6	34.4	275.2	275.8
VOC	0.0013	0.009	0.559	13.4	4.5

Rectisol Flare (S-7616-32-0) - Annual Potential Emissions					
Pollutant	**From 0.3 MMBtu/hr Pilot**		**From Rectisol Flare Operation**		**Maximum Emissions (lb/yr)**
	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr) based on 8760 hr/yr	Emission Factor (lb/hr)	Annual Emissions (lb/yr) based on 40 hr/yr and 430 MMBtu/hr planned flaring limit	Total (lb/yr)
NO_X	0.068	179	29.2	1,168	1,347
SO_X	0.00214	6	15.0	600	606
PM_{10}	0.003	8	1.29	52	60
CO	0.08	210	34.4	1,376	1,586
VOC	0.0013	3	0.559	22	25

Ammonia Synthesis Plant (S-7616-33-0)

Ammonia Synthesis Plant Startup Heater

The PE2 for the ammonia synthesis startup heater for each pollutant is calculated with the following equation:

PE2 = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Operating Schedule (hr/day or hr/year)

Pollutant	Daily PE2 for Startup Heater			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/day)	Daily PE2 (lb/day)
NO_X	0.011	56	24	14.8
SO_X	0.00285	56	24	3.8
PM_{10}	0.0050	56	24	6.7
CO	0.037	56	24	49.7
VOC	0.0040	56	24	5.4

Pollutant	Annual PE2 for Startup Heater		
	EF2 (lb/MMBtu)	Annual Heat Input Limit (billion Btu/yr)	Annual PE2 (lb/year)
NO_X	0.011	7.84	86
SO_X	0.00285	7.84	22
PM_{10}	0.0050	7.84	39
CO	0.037	7.84	290
VOC	0.0040	7.84	31

Potential Fugitive Emissions for S-7616-33-0		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	0	0
SO_X	0	0
PM_{10}	0	0
CO	0.7	245
VOC	0	0

PE2 for S-7616-33-0 (from Heater and Fugitive Emissions)		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/yr)**
NO_X	14.8	86
SO_X	3.8	22
PM_{10}	6.7	39
CO	49.7 + 0.7 = 50.4	290 + 245 = 535
VOC	5.4	31

Urea Unit (S-7616-34-0)

Urea Absorber:

The only emissions associated with the urea absorber are in the form of ammonia.

Daily PE2:

$PE2_{NH3}$ = (13.1 lb-NH3/hr)(24 hr/day)
= 314.4 lb-NH3/day

Annual PE2:

$PE2_{NH3}$ = (13.1 lb-NH3/hr)(8,052 hr/yr)
= 105,481 lb-NH3/yr

Urea Pastillation Unit:

Emissions are based on the air flow to the collector, hours of operation, and the outlet dust loading of each baghouse. Below is a sample calculation:

Daily PE2 = (Air Flow to Collector)(Grain Loading)
= (1,500 ft^3/min)(24 hr x 60 min/hr)(0.001 gr/dscf)(lb/7,000 gr)
= 0.31 lb-PM10/day

Daily PE2 for S-7616-34-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
30: Urea Bucket Elevator	24	0.001	1,500	0.31
Total Emissions (lb-PM10/day)				0.3

Annual PE2 = (Air Flow to Collector)(Grain Loading)
= (1,500 ft^3/min)(8,760 hr/yr x 60 min/hr)(0.001 gr/dscf)(lb/7,000 gr)
= 112.6 lb-PM10/yr

Annual PE2 for S-7616-34-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Urea Bucket Elevator	8,760	0.001	1,500	112.6
Total Emissions (lb-PM10/yr)				113

Nitric Acid Unit (S-7616-35-0)

Daily PE2:

$PE2_{NOx}$ = (501 ton/day of nitric acid)(0.2 lb-NOx/ton of nitric acid)
= 100.2 lb-NOx/day

$PE2_{NH3}$ = (1.0 lb-NH3/hr)(24 hr/day)
= 24.0 lb-NH3/day

Annual PE2:

$PE2_{NOx}$ = (501 ton/24 hr of nitric acid)(0.2 lb-NOx/ton of nitric acid)(8,052 hr/yr)
= 33,617 lb-NOx/yr

$PE2_{NH3}$ = (1.0 lb-NH3/hr)(8,052 hr/yr)
= 8,052 lb-NH3/yr

Ammonium Nitrate Unit (S-7616-36-0)

Daily PE2:

$PE2_{PM10}$ = (0.2 lb-PM10/hr)(24 hr/day)
= 4.8 lb-PM10/day

Annual PE2:

$PE2_{PM10}$ = (0.2 lb-PM10/hr)(8,052 hr/yr)
= 1,610 lb-PM10/yr

Urea Storage and Handling Operation (S-7616-37-0)

Daily PE2 for S-7616-37-0				
Description	**Operating Capacity (hr/day)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Daily Emissions (lb-PM10/day)**
Urea Transfer Tower 1	24	0.001	1,500	0.31
Urea Transfer Tower 2	24	0.001	1,500	0.31
Urea Transfer Tower 3	24	0.001	1,500	0.31
Urea Transfer Tower 4	24	0.001	1,500	0.31
Urea Transfer Tower 5	8 avg (24 max)	0.001	1,500	0.31
Urea Loading Vent	8 avg (24 max)	0.001	20,000	4.11
Total Emissions (lb-PM10/day)				5.7

Annual PE2 for S-7616-37-0				
Description	**Operating Capacity (hr/yr)**	**Grain Loading (gr/dscf)**	**Nominal Air Flow to Collector (acfm)**	**Annual Emissions (lb-PM10/yr)**
Urea Transfer Tower 1	8,760	0.001	1,500	112.6
Urea Transfer Tower 2	2,190	0.001	1,500	28.2
Urea Transfer Tower 3	4,380	0.001	1,500	56.3
Urea Transfer Tower 4	2,190	0.001	1,500	28.2
Urea Transfer Tower 5	2,080	0.001	1,500	26.7
Urea Loading Vent	2,080	0.001	20,000	356.6
Total Emissions (lb-PM10/yr)				609

Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0)

Daily Post-Project Emissions (for Each Engine)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hr/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	0.5	2,922	24	453.6	77.3
SO_X	0.0051	2,922	24	453.6	0.8
PM_{10}	0.07	2,922	24	453.6	10.8
CO	2.6	2,922	24	453.6	402.0
VOC	0.3	2,922	24	453.6	46.4

Annual Post-Project Emissions (for Each Engine)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hr/yr)	Conversion (g/lb)	PE2 Total (lb/yr)
NO_X	0.5	2,922	50	453.6	161
SO_X	0.0051	2,922	50	453.6	2
PM_{10}	0.07	2,922	50	453.6	23
CO	2.6	2,922	50	453.6	837
VOC	0.3	2,922	50	453.6	97

Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0)

Daily Post-Project Emissions (for Engine S-7616-40)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hr/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	1.5	556	24	453.6	44.1
SO_X	0.0051	556	24	453.6	0.2
PM_{10}	0.015	556	24	453.6	0.4
CO	2.6	556	24	453.6	76.5
VOC	0.14	556	24	453.6	4.1

Annual Post-Project Emissions (for Engine S-7616-40-0)					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hr/yr)	Conversion (g/lb)	PE2 Total (lb/yr)
NO_X	1.5	556	100	453.6	184
SO_X	0.0051	556	100	453.6	1
PM_{10}	0.015	556	100	453.6	2
CO	2.6	556	100	453.6	319
VOC	0.14	556	100	453.6	17

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Determination of Compliance (DOC) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid DOC or ERCs banked at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Determinations of Compliance (DOC) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Unit		NO_X	SO_X	PM_{10}	$PM_{2.5}$[36]	CO	VOC
S-7616-17-0 - Rail unloading, transfer		0	0	267	267	0	0
S-7616-18-0 - Truck unloading, transfer		0	0	2,140	2,140	0	0
S-7616-19-0 - Feedstock storage, blending, reclaim		0	0	125	125	0	0
S-7616-20-0 - Feedstock drying, crushing operation		0	0	946	946	0	0
S-7616-21-0 - Gasification system		0	65	0	0	8,915	24,036
S-7616-22-0 - Gasification solids handling		0	0	514	387	0	0
S-7616-23-0 - Sulfur recovery		27,322	21,587	865	865	23,736	626
S-7616-24-0 - CO2 recovery, vent		0	0	0	0	250,121	7646
S-7616-25-0 - Auxiliary boiler		2,796	1,328	2,330	2,330	17,242	1,864
S-7616-26-0 - Combined cycle power generating system + Feedstock dryer	HRSG	212,953	34,445	107,813	107,813	177,980	30,506
	Dryer	33,773	5,605	11,257	11,257	25,528	4,816
	Total	246,726	40,050	119,070	119,070	203,508	35,322
S-7616-27-0 - Cooling tower		0	0	30,438	18,248	0	0
S-7616-28-0 - Cooling tower		0	0	1,867	1,120	0	0
S-7616-29-0 - Cooling tower		0	0	18,640	11,175	0	0
S-7616-30-0 - Flare		5,094	169	490	490	36,913	109
S-7616-31-0 - Flare		277	742	12	12	326	5
S-7616-32-0 - Flare		1,347	606	60	60	1,586	25
S-7616-33-0 – Ammonia startup heater		86	22	39	39	535	31
S-7616-34-0 – Urea unit		0	0	113	113	0	0
S-7616-35-0 – Nitric acid unit		33,617	0	0	0	0	0
S-7616-36-0 – Ammonium nitrate unit		0	0	1,610	1,610	0	0
S-7616-37-0 - Urea storage and handling		0	0	609	609	0	0
S-7616-38-0 - Emergency engine		161	2	23	23	837	97
S-7616-39-0 – Emergency engine		161	2	23	23	837	97
S-7616-40-0 – Emergency engine		184	1	2	2	319	17
		NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
Post-Project SSPE (SSPE2)		317,771	64,574	180,183	159,654	544,875	69,875

[36] A fraction ratio of 0.6 $PM_{2.5}$:PM_{10} is assumed for the cooling towers as is explained in Section VI.

5. Major Source Determination

Rule 2201 Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. However, for the purposes of determining major source status, the SSPE2 shall not include the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site."

Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	317,771	64,574	180,183	159,654	544,875	69,875
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	Yes	No	Yes	No	Yes	Yes

As seen in the table above, the facility is not an existing Major Source for any pollutant; however, is becoming a Major Source for NOx, PM10, CO, and VOC emissions as a result of this project.

Rule 2410 Major Source Determination

The facility or the equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination (tons/year)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Estimated Facility PE before Project Increase	0	0	0	0	0	0	0
PSD Major Source Thresholds	100	100	100	100	100	100	100,000
PSD Major Source ? (Y/N)	No	No	No	No	No	No	No

As shown above, the facility is not an existing major source for PSD for at least one pollutant. Therefore the facility is not an existing major source for PSD.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since these are all new emission units, BE = PE1 = 0 for all criteria pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is a new major source, it is not an SB 288 major modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to pollutants for which the District is in attainment or for unclassified pollutants. The pollutants addressed in the PSD applicability determination are listed as follows:

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- VOC
- Greenhouse gases (GHG): CO2, N2O, CH4, HFCs, PFCs, and SF6
- Lead
- Fluorides
- Sulfuric acid mist
- Hydrogen sulfide
- Total reduced sulfur (including H2S)
- Reduced sulfur compounds (including H2S)

The first step of this PSD evaluation consists of determining whether the facility is an existing PSD Major Source. As shown in Section Vll.C.5, the facility is not an existing major source for PSD.

As the facility is a new major source for PSD, the second step of the PSD evaluation is to determine if the emission increases due to the facility are above the PSD significance thresholds.

Potential to Emit for New Emission Units vs. PSD Major Source Thresholds

The project potential to emit from all new units is compared to the PSD major source threshold.

The equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination: Potential to Emit (tons/year)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Total PE from New Units	158.9	34.9	32.3	272.4	90.1	90.1	593,965
PSD Major Source threshold	100	100	100	100	100	100	100,000
New PSD Major Source?	Yes	No	No	Yes	No	No	Yes

As demonstrated in the table above, the project potential to emit, for all new emission units exceeds one or more of the PSD major source thresholds. Therefore, the facility is a new major source for PSD.

I. Significance of Project Emission Increase Determination for Each Attainment/Unclassified Pollutant

a. Project Location Relative to Class 1 Area

As demonstrated in the section above, the project emission increase, for all new and modified emission units, exceeds one or more of the PSD major source thresholds. Because the project is not located within 10 km of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

b. PSD Significant Emission Increase Determination For Each Attainment/ Unclassified Pollutant

As demonstrated above, the project was determined to be a new PSD major source for at least one pollutant. As a result, a PSD significant emission increase determination for all attainment/unclassified pollutant is required.

Below is a comparison of the emission increases for the project and the PSD significance thresholds.

PSD Significant Emission Increase Determination: Emission Increase (ton/yr)						
	NO2	SO2	CO	PM	PM10	CO2e
Emission Increases only	158.9	32.3	272.4	90.1	90.1	593,965
PSD Significance Threshold	40	40	100	25	15	75,000
Significant Emission Increase?	Yes	No	Yes	Yes	Yes	Yes

Additionally, the PSD significance thresholds and the emission increases[37] for the following pollutants are listed in the table below:

PSD Significant Emission Increase Determination: Emission Increase (ton/yr)			
	Emission increases only	PSD Significance Threshold	Significant Emission Increase?
Lead	0.007	0.6	No
Fluorides	0.001	3	No
Sulfuric acid mist	1.12	7	No
Hydrogen sulfide (H2s)	2.44	10	No
Total reduced sulfur (including H2S)	4.02	10	No
Reduced sulfur compounds (including H2S)	4.26	10	No
Municipal waste combustor organics (measured as total tetra-through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	0	3.5×10^{-6}	No
Municipal waste combustor metals (measured as particulate matter)	0	15	No
Municipal waste combustor acid gases (measured as sulfur dioxide and hydrogen chloride)	0	40	No
Municipal solid waste landfills emissions (measured as nonmethane organic compounds)	0	50	No

[37] These emission increases are tabulated in Table 8-4 of the PSD application, which is found in Appendix F of this evaluation.

As demonstrated in the two tables above, the project results in a PSD significant emissions increase for the following pollutants: NO2, CO, PM, PM10, and CO2e. As such, the project is subject to Rule 2410 for NO2, CO, PM, PM10, and CO2e.

Therefore, BACT and modeling is required for NO2, CO, PM, PM10. Please note that if the project is subject to Rule 2410 for greenhouse gas (GHG) emissions, BACT is required, but modeling is not required for CO2e (as there is not an AAQS for CO2e).

Rule 2410 Requirements

For projects subject to the requirements of District Rule 2410, the following are required:

I. BACT is required for NO2, CO, PM, PM10, and GHGs
II. Ambient air quality impact analysis (including secondary emissions), see 40CFR 52.21(k), (except for GHG emission increases)
III. Ambient air quality monitoring, see 40CFR 52.21(m), (except for GHG emission increases)
IV. Additional impact analyses, including visibility, soils, vegetation, see 40CFR 52.21(o), (except for GHG emission increases)
V. Public noticing requirements pursuant to Rule 2410 and District guidance

See Section VIII (Compliance) for a discussion of Rule 2410 compliance.

VIII. Compliance

Rule 1080 - Stack Monitoring

This rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the DOC are consistent with the requirements of this Rule. Compliance with the requirements of this rule is anticipated.

S-7616-26-0 (Combustion Turbine Generator)

The CTG will be equipped with operational CEMs for NOx, CO, and O2. Provisions included in the DOC are consistent with the requirements of this Rule. Compliance with the requirements of this rule is anticipated.

Proposed Rule 1080 Conditions:

- The permittee shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; a negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

S-7616-35-0 (Nitric Acid Plant)

The nitric acid will be equipped with operational CEMs for NOx. Provisions included in the DOC are consistent with the requirements of this rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60. [District Rules 2201, 1080, and 40 CFR 60 Subpart Ga]

- The permittee shall perform a relative accuracy test audit (RATA) for the NOx CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080 and 40 CFR 60 Subpart Ga]

- The permittee must operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of §60.13 and Performance Specification 6 of

Appendix B of part 60 and the specifications of Section 60.73a (Subpart Ga). [District Rule 1080 and 40 CFR 60 Subpart Ga]

- The permittee must conduct an initial performance test to demonstrate compliance with the NOx emissions limit under §60.72a(a) beginning in the calendar month following initial certification of the NOx and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NOx average concentration, mass flow rate recorded with the certified NOx concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. The permittee must assure that the CERMS meets all of the data quality assurance requirements as per §60.13 and Appendix F, Procedure 1, of this part and you must use the data from the continuous emissions rate monitoring system (CERMS) for this compliance determination. [District Rule 1080 and 40 CFR 60 Subpart Ga]

- The permittee shall maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications. For each malfunction, the permittee shall maintain records of the following information: (1) records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment; (2) records of actions taken during periods of malfunction to minimize emissions in accordance with section 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [District Rule 1080 and 40 CFR 60 Subpart Ga]

- The permittee to submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the Administrator at the appropriate address as shown in 40 CFR 60.4. The permittee shall report to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard: (1) Time period; (2) NOx emission rates (lb/ton of acid produced); (3) Reasons for noncompliance with the emissions standard; and (4) Description of corrective actions taken. The permittee shall also report the following whenever they occur: (1) Times when the pollutant concentration exceeded full span of the NOx pollutant monitoring equipment; and (2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [District Rule 1080 and 40 CFR 60 Subpart Ga]

Rule 1081 - Source Sampling

This rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The requirements of this rule will be included in the DOC. Compliance with this Rule is anticipated.

S-7616-26-0 (Combustion Turbine Generator)
Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

S-7616-27-0 (Gasification Process Area Cooling Tower)
S-7616-28-0 (Air Separation Unit Cooling Tower)
S-7616-29-0 (Power Block Cooling Tower)
Proposed Rule 1081 Condition:

- Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

S-7616-23-0 (Sulfur Recovery Unit/Thermal Oxidizer)
Proposed Rule 1081 Conditions:

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used NOx: EPA Method 7E or 20, CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA method 18 or 25 and SOx: EPA Method 6, 6B or 8. EPA or CARB approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 2201]

S-7616-24-0 (CO2 Recovery and Vent System)
Proposed Rule 1081 Conditions:

- Permittee shall conduct an initial speciated HAPs and total VOC source test for the CO2 recovery and vent system by District witnessed in situ sampling of vented stream by a qualified independent source test firm. The permittee shall determine the total HAPs emissions rate, the single highest HAP emission rate, and the VOC mass emission during the source test. Initial compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates determined during initial compliance source testing and the correlation between VOC emissions and HAP(s). Ongoing compliance shall be determined using mass flow and VOC sampling during venting occurrences as described in the condition below. [District Rule 4002]

- The vent stream composition of CO, VOC, H2S, COS, and the HAPs identified in the initial speciated HAPs and total VOC source test, shall be measured during each venting occurrence exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District in writing. [District Rule 2201]

S-7616-25-0 (Auxiliary Boiler)
Proposed Rule 1081 Conditions:

- This unit shall be tested for compliance with the NOx and CO emissions limits within 60 days of initial startup and at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)
Proposed Rule 1081 Conditions:

- This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

S-7616-35-0 (Nitric Acid Unit)
Proposed Rule 1081 Conditions:

- Source testing to quantify N2O emissions (lb-N2O/ton of HNO3 produced) shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081, 2201, and 2410]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {33} Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

S-7616-36-0 (Ammonium Nitrate Unit)
Proposed Rule 1081 Conditions:

- Source testing to quantify PM10 emissions (lb-PM10/hr and lb-PM10/ton of ammonium nitrate produced) from scrubber vent shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081 and 2201]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The following test methods shall be used PM10: EPA method 5 (front half and back half). Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 2201]

- {33} Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 - Equipment Breakdown

This rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

The requirements of this rule will be included in the DOC. Compliance with this rule is anticipated.

S-7616-26-0 (Combustion Turbine Generator)

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 - Permits Required

This rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC (or in the case of this project, a Determination of Compliance (DOC)). With the submission of this application, the applicant is complying with the requirements of this rule.

Rule 2201 - New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

All of the emissions units in this project are new emissions units. The units' PEs are calculated in Section VII.C.2 of this evaluation.

S-7616-26-0 (Combustion Turbine Generator)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new CTG with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

The PE of ammonia is greater than 2.0 pounds per day for the CTG. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NOx. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

S-7616-17-0 (Railcar Unloading and Transfer System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Railcar Unloading and Transfer System with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lb/day.

S-7616-18-0 (Truck Unloading and Transfer System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Truck Unloading and Transfer System with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lb/day.

S-7616-19-0 (Feedstock Storage, Blending, and Reclaim System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Feedstock Storage, Blending, and Reclaim System with a PE less than 2 lb/day for PM10. Therefore, BACT is not triggered since the PEs for all criteria pollutants are less than 2 lb/day.

S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Feedstock Grinding/Crushing and Drying System with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lb/day.

S-7616-21-0 (Gasification System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Gasification System with a PE greater than 2 lb/day for CO and VOC. BACT is triggered for CO and VOC since the PE is greater than 2 lb/day.

S-7616-22-0 (Gasification Solids Handling System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Gasification Solids Material Handling System with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lb/day.

S-7616-23-0 (Sulfur Recovery System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Sulfur Recovery System which would result in a PE greater than 2 lb/day for SOx. BACT is triggered for SOx since the PE is greater than 2 lb/day, as demonstrated in Section VII.C.5 of this document.

S-7616-24-0 (CO2 Recovery and Vent System)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new CO2 Recovery and Vent System with a PE greater than 2 lb/day for CO and VOC. BACT is triggered for CO and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-25-0 (Auxiliary Boiler)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas fired auxiliary boiler with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-27-0, -28-0, and -29-0 (Cooling Towers)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install three new cooling towers, each with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lb/day, as demonstrated in Section VII.C.5 of this document.

S-7616-30-0 (Gasification Flare)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new gasification flare with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, VOC, and CO. BACT is triggered for NO_X, SO_X, PM_{10}, VOC, and CO since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-31-0 (Sulfur Recovery Unit Flare)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new sulfur recovery flare with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, and CO. BACT is triggered for NO_X, SO_X, PM_{10}, and CO since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-32-0 (Rectisol Flare)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new Rectisol flare with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-33-0 (Ammonia Startup Heater)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired startup heater that will serve the ammonia synthesis unit with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-34-0 (Urea Absorber and Urea Pastillation Unit)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new urea absorber vent and a new pastillation unit with a PE that is less than 2 lb/day for PM_{10} and the other criteria pollutants. Therefore, BACT is not triggered since the PEs for all criteria pollutants are less than 2 lb/day.

S-7616-35-0 (Nitric Acid Unit)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new nitric acid unit with a PE greater than 2 lb/day for NO_X. BACT is triggered for NO_X, since the PE is greater than 2 lb/day.

S-7616-36-0 (Ammonium Nitrate Unit)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install a new ammonium nitrate unit with a PE greater than 2 lb/day for PM_{10}. BACT is triggered for PM_{10} since the PE is greater than 2 lb/day.

S-7616-37-0 (Urea Storage and Handling Operation)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install urea storage and handling system with a PE that is less than 2 lb/day for PM_{10} for the urea loading area. Therefore, BACT is triggered for the urea loading area since the PEs for all criteria pollutants are less than 2 lb/day.

S-7616-38-0 and -39-0 (Emergency Engines Powering Electrical Generators)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install two new diesel-fired emergency engines powering electrical generator with a PE greater than 2 lb/day for NO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, PM_{10}, CO and VOC since the PEs are greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

As explained in Section VII.C.2 of this evaluation, the applicant is proposing to install one new diesel-fired emergency engine powering a firewater pump with a PE greater than 2 lb/day for NO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, PM_{10}, CO and VOC since the PEs are

greater than 2 lb/day and the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.5 of this document.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project; therefore BACT is not triggered.

d. Major Modification

As discussed in Section VII.C.7 above, this project does not constitute a Major Modification; therefore BACT is not triggered.

2. BACT Guidelines

The BACT Guidelines mentioned below are located in Appendix B of this document.

S-7616-26-0 (Combustion Turbine Generator)

- A new BACT Guideline was developed in project S-1093741. A summary sheet of the requirements is included in Appendix B.

S-7616-17-0 (Railcar Unloading and Transfer System)
S-7616-18-0 (Truck Unloading and Transfer System)
S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)

- BACT Guideline 8.2.1 applies to Petroleum Coke Handling - Receiving, Storage, and Loadout = or > 1,000 tons coke per day.

- BACT Guideline 8.4.1 applies to Dry Material Storage and Conveying Operation, 100 tons/day.

- BACT Guideline 8.4.3 applies to Dry Material Handling - Mixing, Blending, Milling, or Storage.

S-7616-22-0 (Gasification Solids Handling System)
S-7616-37-0 (Urea Storage and Handling Operation)

- BACT Guideline 8.4.1 applies to Dry Material Storage and Conveying Operation, 100 tons/day.

- BACT Guideline 8.4.2 applies to Wet Material Storage and Conveying Operation, 200 tons/day.

- BACT Guideline 8.4.3 applies to Dry Material Handling - Mixing, Blending, Milling, or Storage.

S-7616-21-0 (Fugitive Emissions from Gasification System)

- BACT Guideline 4.12.1 applies to Chemical Plants - Valves and Connectors.

- BACT Guideline 4.12.2 applies to Chemical Plants - Pump and Compressor Seals.

S-7616-23-0 (Sulfur Recovery System):

- BACT Guideline 7.2.6 (Petroleum Refineries and Chemical Plants, Sulfur Recovery Plant, = or > 20 tons sulfur/day), applies to the sulfur recovery system.

- BACT Guideline 4.12.1 applies to Chemical Plants - Valves and Connectors.

- BACT Guideline 4.12.2 applies to Chemical Plants - Pump and Compressor Seals.

S-7616-24-0 (CO2 Recovery and Vent System)

- A new BACT Guideline was developed in project S-1093741. A summary sheet of the requirements is included in Appendix B.

S-7616-25-0 (Auxiliary Boiler)

- BACT Guidelines 1.1.1 to 1.1.8 have been rescinded. Please note that BACT Guideline 1.1.2 [Steam Generator $\geq$ 20 MMBtu/hr] has been rescinded. The NO_X emission limit requirement of District Rule 4320 is lower than the Achieved-in-Practice requirement of BACT Guideline 1.1.2 (9 ppmv @ 3% O2); therefore a project specific BACT analysis will be performed to determine BACT for this project. More details regarding this are provided in the Top-Down BACT Analysis in Appendix C.

S-7616-27-0 (Gasification Process Area Cooling Tower)
S-7616-28-0 (Air Separation Unit Cooling Tower)
S-7616-29-0 (Power Block Cooling Tower)

- BACT Guideline 8.3.10 applies to Cooling Tower – Induced Draft, Evaporative Cooling).

S-7616-30-0 (Gasification Flare)
S-7616-31-0 (Sulfur Recovery Unit Flare)
S-7616-32-0 (Rectisol Flare)

- BACT Guideline 1.4.8 (Refinery Flare) applies to the flares.

S-7616-33-0 (Ammonia Startup Heater)

- BACT Guidelines 1.1.1 to 1.1.8 have been rescinded. Please note that BACT Guideline 1.1.2 [Steam Generator $\geq$ 20 MMBtu/hr] has been rescinded. The NO_X emission limit requirement of District Rule 4320 is lower than the Achieved-in-Practice requirement of BACT Guideline 1.1.2 (9 ppmv @ 3% O2); therefore a project specific BACT analysis will be performed to determine BACT for this project. More details regarding this are provided in the Top-Down BACT Analysis in Appendix C.

S-7616-35-0 (Nitric Acid Unit)

- A new BACT Guideline was developed for this project. A summary sheet of the requirements is included in Appendix B.

S-7616-36-0 (Ammonium Nitrate Unit)

- A new BACT Guideline was developed for this project. A summary sheet of the requirements is included in Appendix B.

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)

- BACT Guideline 3.1.1 (Emergency Diesel IC Engine), applies to the diesel-fired emergency IC engines.

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

- BACT Guideline 3.1.1 (Emergency Diesel IC Engine), applies to the diesel-fired emergency IC engine.

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see Appendix C), BACT has been satisfied with the following:

S-7616-26-0 (Combustion Turbine Generator)

NOx: Selective catalytic reduction that does not exceed 2.5 ppmvd-NOx @ 15% O_2 (1-hour average) when firing on hydrogen-rich fuel, except during startup/shutdown; and selective catalytic reduction that does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour average) when firing on natural gas, except during startup/shutdown

SOx: PUC-regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.0003 lb-SOx/MMBtu when firing on hydrogen-rich fuel

CO: Oxidation catalyst that does not exceed 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel, and does not exceed 5.0 ppmvd @ 15% O2 when firing on natural gas, except during startup/shutdown

VOC: Oxidation catalyst that does not exceed 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel, and does not exceed 2.0 ppmvd-VOC when firing on natural gas, except during startup/shutdown

PM_{10}: Air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, non-PUC regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel exclusively.

S-7616-17-0 (Railcar Unloading and Transfer System)
S-7616-18-0 (Truck Unloading and Transfer System)
S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)

PM_{10}: Petroleum coke handling: adequate moisture content of coke received, and loaded out, to prevent visible emissions in excess of 5% opacity.

Dry material handling: mixer, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse.

Dry material storage and conveying operation: storage, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse.

S-7616-22-0 (Gasification Solids Handling System)
S-7616-37-0 (Urea Storage and Handling Operation)

PM_{10}: Dry material storage and conveying operation: storage, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse.

Wet material storage and conveying operation: enclosed storage with sufficient moisture so visible emissions are less than 5% opacity from any single emission point.

S-7616-21-0 (Fugitive Emissions from Gasification System)

VOC: Leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. Leak defined as a reading of methane in excess of 500 ppmv above background for

pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455.

S-7616-23-0 (Sulfur Recovery System):

SOx: Sulfur recovery unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator, except during startup and shutdown

S-7616-23-0 (Fugitive Emissions from Sulfur Recovery System):

VOC: Leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. Leak defined as a reading of methane in excess of 500 ppmv above background for pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455.

S-7616-24-0 (CO2 Recovery and Vent System)

CO and VOC: Capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation); venting allowed when transportation system is unavailable due to upset condition up to 504 hr (or equivalent) per rolling 12-month period.

S-7616-25-0 (Auxiliary Boiler)

VOC: PUC-quality natural gas firing
SOx: PUC-quality natural gas firing
NOx: 5 ppmvd @ 3% O_2
CO: PUC-quality natural gas firing
PM_{10}: PUC-quality natural gas firing

S-7616-27-0 (Gasification Process Area Cooling Tower)
S-7616-28-0 (Air Separation Unit Cooling Tower)
S-7616-29-0 (Power Block Cooling Tower)

PM_{10}: Cellular-type drift eliminator

S-7616-30-0 (Gasification Flare)
S-7616-31-0 (Sulfur Recovery Unit Flare)
S-7616-32-0 (Rectisol Flare)

CO: Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a

flare gas recovery system for non-emergency releases or equivalent District approved controls.

NOx: Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx or less than 0.068 lb/MMBtu. Flare shall be equipped with a flare gas recovery system for non-emergency releases or equivalent District approved controls.

PM_{10}: Engineered flare designed for and operated without visible emissions, except as allowed by 40 CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases or equivalent District approved controls. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

SOx: Flare shall be equipped with a flare gas recovery system for non-emergency releases or equivalent District approved controls. Pilot and purge gas shall be natural gas, treated refinery gas or LPG.

VOC: Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of ≥ 98.5%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases or equivalent District approved controls, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

S-7616-33-0 (Ammonia Synthesis Startup Heater)

VOC: PUC-quality natural gas firing
SOx: PUC-quality natural gas firing
NOx: 9 ppmvd @ 3% O_2
CO: PUC-quality natural gas firing
PM_{10}: PUC-quality natural gas firing

S-7616-35-0 (Nitric Acid Unit)

NOx: Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis

S-7616-36-0 (Ammonium Nitrate Unit)

PM_{10}: Wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

CO:	Latest EPA Tier Certification level for applicable horsepower range
NOx:	Latest EPA Tier Certification level for applicable horsepower range
PM_{10}:	0.15 g/hp-hr or the Latest EPA Tier Certification level for applicable horsepower range, whichever is more stringent. (ATCM)
SOx:	Very low sulfur diesel fuel (15 ppmw sulfur or less)
VOC:	Latest EPA Tier Certification level for applicable horsepower range

B. Offsets

1. Offset Applicability

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-Project Stationary Source Potential to Emit (SSPE2) equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The following table compares the post-project facility-wide annual emissions in order to determine if offsets will be required for this project.

Offset Determination (lb/year)						
	NO_X	SO_X	PM_{10}	CO	VOC	
Post-Project SSPE (SSPE2)	317,771	64,574	180,183	544,875	~~69,847~~ 70,747	70,747
Offset Threshold	20,000	54,750	29,200	200,000	20,000	
Offsets Triggered?	Yes	Yes	Yes	Yes	Yes	

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NOx, SOx, PM10, CO, and VOC; therefore offset calculations will be required for this project.

Additionally, as the project had a modeled impact for PM2.5 greater than the applicable significance impact levels, offsets for PM2.5 are being provided for all increases in PM2.5 emissions (without excluding any offset threshold or emissions from emergency equipment). Please note that because the facility is not a major source for PM2.5, i.e. emissions less than 100 ton/year, PM2.5 emission offsets are not otherwise required for the project. See PM2.5 offset discussion below.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = [(SSPE2 – ROT + ICCE) x DOR]

Where,

SSPE2	=	Post Project Stationary Source Potential to Emit
ROT	=	Respective Offset Threshold, for the respective pollutant indicated in Section 4.5.3.
ICCE	=	Increase in Cargo Carrier Emissions
DOR	=	Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, units S-7616-38, -39, and -40 for emergency IC engines will be exempt from providing offsets and the emissions associated with these units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offsets Required (lb/year) = [(SSPE2 – Emergency Equipment – ROT + ICCE) x DOR]

Emission Reduction Certificates Proposed for this Project (lb/qtr)					
Pollutant	**Certificate**	**1st Quarter**	**2nd Quarter**	**3rd Quarter**	**4th Quarter**
NOx	ERC #S-3273-2	120,500	120,500	120,500	120,500
NOx	ERC #C-1058-2	10,100	10,100	10,100	10,100
SOx	ERC #S-3275-5	42,000	42,000	42,000	42,000
SOx	ERC #C-1058-5	24,500	24,500	24,500	24,500
VOC	ERC #S-3305-1	14,625	14,625	14,625	14,625
VOC	ERC #S-3557-1	11,437	11,438	11,438	11,437

NOx Offsets Required:

SSPE2 (NO_X) = 317,771 lb/year

Emergency Equipment:
S-7616-38-0 (NO_X) = 161 lb/year
S-7616-39-0 (NO_X) = 161 lb/year
S-7616-40-0 (NO_X) = 184 lb/year

Respective offset threshold (NO_X) = 20,000 lb/year

ICCE = 0 lb/year

Offsets Required (lb/yr) = [(317,771 - 161 -161 - 184 - 20,000 + 0) x DOR]
= 297,265 x DOR

Calculating the appropriate quarterly emissions to be offset are as follows (in lb/qtr without distance ratio) is calculated by dividing the annual offsets required by four:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
74,316	74,316	74,316	74,316

The applicant has stated that the facility plans to use ERC certificate S-3273-2 and C-1058-2, which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of NO_X ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 297,265 x 1.5
= 445,898 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
111,474	111,474	111,474	111,474

The applicant has stated that the facility plans to use ERC certificates S-3273-2 and C-1058-2 to offset the increases in NO_X emissions associated with this project. The above certificates have available quarterly NO_X credits as follows:

(lb/qtr)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-3273-2	120,500	120,500	120,500	120,500
ERC #C-1058-2	10,100	10,100	10,100	10,100
Total	130,600	130,600	130,600	130,600

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

SOx Offsets Required:

SSPE2 (SOx) = 64,574 lb/year

Emergency Equipment:
S-7616-38-0 (SOx) = 2 lb/year
S-7616-39-0 (SOx) = 2 lb/year
S-7616-40-0 (SOx) = 1 lb/year

Respective offset threshold (SOx) = 54,750 lb/year

ICCE = 0 lb/year

Offsets Required (lb/yr) = [(64,574 - 2 - 2 -1 - 54,750 + 0) x DOR]
= 9,819 x DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2,455	2,455	2,455	2,455

The applicant has stated that the facility plans to use ERC certificate S-3275-5 and C-1058-5, which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of SO_X ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 9,819 x 1.5
= 14,729 lb-SO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
3,682	3,682	3,682	3,682

The applicant has stated that the facility plans to use ERC certificates S-3275-5 and C-1058-5 to offset the increases in SO_X emissions associated with this project. The above certificates have available quarterly SO_X credits as follows:

(lb-SOx/qtr)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC # S-3275-5	42,000	42,000	42,000	42,000
ERC # C-1058-5	24,500	24,500	24,500	24,500
Total:	66,500	66,500	66,500	66,500

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X emissions increases associated with this project.

Additionally, the applicant plans to satisfy their offset requirements for PM10 emission increases by providing SOx reductions in place of PM10 reductions. Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM10 and PM10 precursors (i.e. SOx) may be allowed. The applicant is proposing to use the District-approved interpollutant ratio of 1:1 of SOx offsets for PM10.

This interpollutant ratio was developed using elements form the District's 2008 PM2.5 attainment plan. In fact the analysis in this plan performed supported an interpollutant ratio of less than 1:1. However to be conservative and consistent with the requirements of Rule 2201, the interpollutant ratio between SOx and PM10 has been set at 1:1.

The table below indicates the amount of SOx credits necessary to fully offset the quarterly SOx and PM10 increases associated with this project.

(lb/qtr)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Total ERCs available:	66,500	66,500	66,500	66,500
SOx ERCs required:	3,682	3,682	3,682	3,682
PM10/PM2.5 ERCs required: [38]	59,870	59,870	59,870	59,870
Total ERCs required:	63,552	63,552	63,552	63,552

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM10/PM2.5 emissions increases associated with this project.

PM10 Offsets Required:

SSPE2 (PM10) = 180,183 lb/year

Emergency Equipment:
S-7616-38-0 (PM10) = 23 lb/year
S-7616-39-0 (PM10) = 23 lb/year
S-7616-40-0 (PM10) = 2 lb/year

Respective offset threshold (PM10) = 29,200 lb/year

ICCE = 0 lb/year

Offsets Required (lb/yr) = [(180,183 - 23 -23 - 2 - 29,200 + 0) x DOR]
= 150,935 x DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
37,734	37,734	37,734	37,734

As explained in the SOx offset section above, the applicant has stated that the facility plans to use SOx reductions to offset PM10 emission as allowed by the District Rule 2201 Section 4.13.3.2, at a District-approved interpollutant ratio of 1:1 of SOx offsets for PM10. The applicant proposes to use SOx ERC certificates S-3275-5 and C-1058-5, which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 150,935 x 1.5
= 226,403 lb-PM10/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

[38] See the offset calculations for PM10 and PM2.5 in the sections that follow. As is explained in those sections, the offset requirement for PM10 and PM2.5 will be based on the pollutant that requires the greater offset quantities.

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
56,601	56,601	56,601	56,601

The PM2.5 offset requirements will be calculated in the section that follows, and the offset requirement for PM10/PM2.5 will be the based on the pollutant with the greater offset requirement.

PM2.5 Offsets Required:

Offset requirements for modeled impacts of PM2.5 emissions

Rule 2201 section 4.14.1 requires that emissions from new and modified stationary sources (that are subject to public noticing requirements) be modeled to determine if the emissions cause or make worse a violation of an AAQS. In making this determination the District can consider the mitigation of emissions through offsets provided pursuant to Rule 2201.

The modeled impact of PM2.5 emissions from the project exceeds the daily and annual significance impact levels (de minimus levels) for PM2.5 (as shown in Appendix K). As the total PM2.5 emissions from the project will be mitigated by emission offsets, the District has determined that the project will not cause or make worse a violation of the PM2.5 AAQS. Please note that the project is not a "major source" of PM2.5 emissions, as defined in Rule 2201, as its emissions of PM2.5 are less than 100 ton/year. As such Rule 2201 does not explicitly require that PM2.5 emissions be offset for non-major sources of PM2.5.

The offsets provided will mitigate the total PM2.5 emissions from the permitted equipment, including emissions from maintenance and testing of emergency equipment (otherwise exempt from emission offsets). Additionally, no adjustment will be made for the total quantity of offsets provided to account for the PM10 offset threshold of 29,200 lb/year (a portion of which is PM2.5) as is otherwise allowed in Rule 2201 for PM10.

The applicant has proposed to offset PM10 (and PM2.5) emission increases using SOx emission reduction credits as interpollutant offsets. The District has determined that the appropriate interpollutant ratio for SOx emission reductions to be used to offset PM10 emission increases is 1:1 based on chemical mass balance modeling and speciated rollback modeling as performed by the 2008 PM2.5 attainment plan. This same ratio (1:1) is applicable for SOx/PM2.5 interpollutant offsets.

Please note that Rule 2201 section 4.13.3.2 restriction on the use of interpollutant offsets only to those ratios established by EPA or as approved into the SIP by EPA is applicable only for new major sources and major modifications of PM2.5 (consistent with 40 CFR 51.165). As the proposed facility is not a new major source of PM2.5, the requirements of section 4.13.3.2 are not applicable.

The SSPE for PM2.5 for the facility are: 159,654 lb-PM2.5/yr.[39]

Since the applicant will be required to fully offset its PM2.5 emissions down to zero, the amount of PM2.5 offsets required is:

Offsets Required (lb/yr) = 159,654 x DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
39,914	39,914	39,914	39,914

The applicant proposes to use SOx ERC certificates S-3275-5 and C-1058-5 to offset PM10 (and PM2.5), which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 159,654 x 1.5
= 239,481 lb-PM10/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
59,870	59,870	59,870	59,870

As shown above, 59,870 lb/quarter of PM2.5 emission increases will be offset using SOx ERCs. Please note that the quantity of PM2.5 increases to be offset is greater than the quantity of PM10 emission increases to be offset. As all PM2.5 is included in PM10, the quantity of PM2.5 emission required will adequately offset both the PM2.5 and PM10 emission increases.

The table below indicates the amount of SOx credits necessary to fully offset the quarterly SOx and PM10/PM2.5 increases associated with this project.

(lb/qtr)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Total ERCs available:	66,500	66,500	66,500	66,500
SOx ERCs required:	3,682	3,682	3,682	3,682
PM2.5 ERCs required:	59,870	59,870	59,870	59,870
Total ERCs required:	63,552	63,552	63,552	63,552

[39] As is discussed in the Refined AAQA Results in Section 8.2.9.2 of the Ambient Air Quality Impact and Health Risk Assessment Report in Appendix K of this document, HECA will be required to fully offset its PM2.5 emissions down to zero since the emissions for PM2.5 24-hour and annual exceed the NAAQS/CAAQS and SIL thresholds.

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM10/PM2.5 emissions increases associated with this project.

VOC Offsets Required:

SSPE2 (VOC) = 69,875 lb/year

Emergency Equipment:
S-7616-38-0 (VOC) = 97 lb/year
S-7616-39-0 (VOC) = 97 lb/year
S-7616-40-0 (VOC) = 17 lb/year
Respective offset threshold (VOC) = 20,000 lb/year

ICCE = 0 lb/year

Offsets Required (lb/yr) = [(69,875 - 97 -97 - 17 - 20,000 + 0) x DOR]
= 49,664 x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr without distance ratio):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
12,416	12,416	12,416	12,416

The applicant has stated that the facility plans to use ERC certificates S-3305-1 and S-3557-1.

Pursuant to Rule 2201 Section 4.8.1, for NOx and VOC offsets at new major sources and federal major modifications, the distance offset ratio shall be 1.5. The amount of VOC ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 49,664 x 1.5
= 74,496 lb VOC/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
18,624	18,624	18,624	18,624

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

The applicant has stated that the facility plans to use ERC certificates S-3305-1 and portions of S-3306-1 in the future to offset the increases in VOC emissions associated with this project. The above certificates have available quarterly VOC credits as follows:

(lb/qtr)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-3305-1	14,625	14,625	14,625	14,625
ERC #S-3557-1	11,437	11,438	11,438	11,437
Total	26,062	26,063	26,063	26,062

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

CO Offsets Required:

CO offsets are triggered by CO emissions in excess of 200,000 lb/year for the facility. As shown previously, the SSPE2 for CO, after this project, is 544,875 lb/year, so offset requirements are triggered.

However, pursuant to Section 4.6.1, "Emission Offsets shall not be required for the following: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards (AAQS)."

The Technical Services Section of the San Joaquin Valley Unified Air Pollution Control District performed a CO modeling run, using the EPA AERMOD air dispersion model, to determine if the CO emissions from the new facility would exceed the State and Federal AAQS (as shown in the modeling results in Appendix K). Modeling of the worst case 1 hour and 8 hour CO impacts were performed. These values were added to the worst case ambient concentration (background) measured and compared to the ambient air quality standards. Results of the modeling are presented below:

Ambient Modeling Results for CO		
	1 hr std	**8 hr std**
AAQS (ug/m^3)	23,000	10,000
Worst case ambient (background) (ug/m^3)	4,581	2,485
HECA modeled impact	1,849.6	386.8
Facility plus background totals (ug/m^3)	6,430	2,872

This modeling demonstrates that the proposed increase in CO emissions will not cause a violation of the CO ambient air quality standards. Therefore, the increase in CO emissions is exempt from offsets pursuant to Rule 2201 Section 4.6.1.

Proposed Rule 2201 (offset) Conditions:

- Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

- Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, and -33, permittee shall provide SO_X emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

- Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

- Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416lb, 3rd quarter: 12,416lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

- ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

C. Public Notification

1. Applicability

Public noticing is required for:
a. Any new Major Source, which is a new facility that is also a Major Source,
b. Major Modifications,
c. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
d. Any project which results in the offset thresholds being surpassed, and/or
e. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Source

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is greater than the Major Source threshold for NO_X, PM10, CO, and VOC. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in VII.C.7, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE > 100 lb/day

As demonstrated in VII.C.7, this project, this project consists of several emissions units with a Potential to Emit greater than 100 pounds during any one day for any one pollutant. Therefore, public noticing for PE > 100 lb/day purposes is required.

d. Offset Threshold

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/yr)	SSPE2 (lb/yr)	Offset Threshold	Public Notice Required?
NO_X	0	317,771	20,000 lb/year	Yes
SO_X	0	64,574	54,750 lb/year	Yes
PM_{10}	0	180,183	29,200 lb/year	Yes
CO	0	544,875	200,000 lb/year	Yes
VOC	0	70,733	20,000 lb/year	Yes

As detailed above, offset thresholds were surpassed for NO_X, PM10, CO, VOC with this project; therefore public noticing is required for offset purposes.

e. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/yr)	SSPE1 (lb/yr)	SSIPE (lb/yr)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	317,771	0	317,771	20,000 lb/year	Yes
SO_x	64,574	0	64,574	20,000 lb/year	Yes
PM_{10}	180,183	0	180,183	20,000 lb/year	Yes
CO	544,875	0	544,875	20,000 lb/year	Yes
VOC	70,733	0	70,733	20,000 lb/year	Yes

As demonstrated above, the SSIPEs for NO_X, SO_X, PM10, CO, and VOC are greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Action

As discussed above, public noticing is required for this project for new major source, PEs in excess of 100 lb/day, offset threshold being surpassed, and SSIPE greater than 20,000 lb/year. The District shall public notice this project according to the requirements of Section 5.5.

D. Daily Emission Limits (DELs)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.16 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.16.1 and 3.16.2, the DEL must be contained in the latest Determination of Compliance and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

S-7616-26-0 (Combustion Turbine Generator)

- During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 25.0 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 3.5 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 18.3 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 12.9 lb/hr; or SOx (as SO2) - 4.1 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- During normal operation (excluding startup and shutdown), emission rate from the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 4.4 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 0.6 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 3.2 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 1.4 lb/hr; or SOx (as SO2) - 0.9 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on natural gas shall not exceed any of the following: NOx (as NO2) - 34.1 lb/hr and 4.0 ppmvd-NOx @ 15% O2; VOC (as methane) - 5.9 lb/hr and 2.0 ppmvd-VOC @ 15% O2; CO - 26.0 lb/hr and 5.0 ppmvd-CO @ 15% O2; PM10 - 15.0 lb/hr; or SOx (as SO2) - 4.7 lb/hr. All pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Ammonia (NH3) emissions shall not exceed either of the following limits: 18.50 lb/hr or 5.0 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rule 2201]

- During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 107.20 lb/hr, SOx - 2.40 lb/hr, PM10 - 15.00 lb/hr, CO - 2,270.00 lb/hr, or VOC - 65.00 lb/hr, based on one-hour averages. During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 381.2 lb/day, SOx - 10.7 lb/day, PM10 - 59.7 lb/day, CO - 3,385.0 lb/day, or VOC - 67.7 lb/day. [District Rule 2201]

- During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 15.10 lb/hr, SOx - 0.30 lb/hr, PM10 - 0.90 lb/hr, CO - 147.40 lb/hr, or VOC - 1.90 lb/hr, based on one-hour averages. During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 49.0 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 317.8 lb/day, or VOC - 5.2 lb/day. [District Rule 2201]

- During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 122.0 lb/hr, SOx - 2.7 lb/hr, PM10 - 15.0 lb/hr, CO - 2,270.0 lb/hr, or VOC - 64.8 lb/hr, based on one-hour averages. During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 766.6 lb/day, SOx - 21.9 lb/day, PM10 - 127.0 lb/day, CO - 8,437.0 lb/day, or VOC - 193.9 lb/day. [District Rule 2201]

- During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 9.4 lb/hr, SOx - 0.3 lb/hr, PM10 - 0.9 lb/hr, CO - 11.5 lb/hr, or VOC - 0.7 lb/hr, based on one-hour averages. During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 37.6 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 46.0 lb/day, or VOC - 2.8 lb/day. [District Rule 2201]

- Daily emissions from the CTG/HRSG stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 600.0 lb/day; CO - 439.2 lb/day; VOC - 84.0 lb/day; PM10 - 309.6 lb/day; SOx (as SO2) - 98.4 lb/day, or NH3 - 444.0 lb/day. [District Rule 2201]

- Daily emissions from the CTG/HRSG stack when firing on natural gas on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 818.4 lb/day; CO - 624.0 lb/day; VOC - 141.6 lb/day; PM10 - 360.0 lb/day; SOx (as SO2) - 112.8 lb/day, or NH3 - 379.2 lb/day. [District Rule 2201]

- Daily emissions from the feedstock dryer stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 105.6 lb/day; CO - 76.8 lb/day; VOC - 14.4 lb/day; PM10 - 33.6 lb/day; SOx (as SO2) - 21.6 lb/day, or NH3 - 76.8 lb/day. [District Rule 2201]

S-7616-17-0 (Railcar Unloading and Transfer System)

- PM10 emissions shall not exceed any of the following emissions for the following operation(s): rail unloading station: 4.1 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed the any of the following name plate capacities: rail unloading station: 20,000 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

S-7616-18-0 (Truck Unloading and Transfer System)

- PM10 emissions shall not exceed any of the following emissions for the following operation(s): truck unloading station: 16.5 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: truck unloading station: 80,000 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

S-7616-19-0 (Feedstock Storage, Blending, and Reclaim System)

- PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 0.3 lb/day; feedstock transfer tower 2: 0.3 lb/day; fluxant unloading vent: 0.3 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: feedstock transfer tower 1: 1,500 cfm; feedstock transfer tower 2: 1,500 cfm; fluxant unloading vent: 1,500 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)

- PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock bunkers: 2.6 lb/day; feedstock crusher: 2.6 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: feedstock bunkers: 12,600 cfm; feedstock crusher: 12,600 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

S-7616-21-0 (Gasification System)

- Fugitive VOC emission rate from the unit shall not exceed 65.9 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: methanol, propylene, H2S-laden methanol, CO2-laden methanol, acid gas, ammonia laden gas, lower benzene concentration, and higher benzene concentration. The following control efficiencies in Tables 5-1 and 5-2 of the EPA document shall apply to those components under an LDAR program: gas valves: 92%; light liquid valves: 88%; light liquid pump seals: 100%; compressor seals: 100%; and connectors: 93%. Light liquid pump seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the pumped fluid. Compressor seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the compressed gas. [District Rules 2201 and 2410]

- Fugitive CO and SOx emission rate from the unit shall not exceed 24.4 lb-CO/day nor 0.2 lb-SOx/day based on the component count, CO percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

- The VOC content of the gas in the following streams shall not exceed 10% by weight: syngas, shifted syngas, sour water, acid gas, ammonia-laden gas. [District Rule 2201]

S-7616-22-0 (Gasification Solids Material Handling System)

- PM10 emissions shall not exceed any of the following emissions for the following operation(s): gasification solids bucket elevator: 0.6 lb/day; gasification solids transfer tower: 0.6 lb/day; gasification solids load-out system: 2.1 lb/day; gasification solids pad stacking: 0.2 lb/day; gasification solids pad reclaim: 0.3 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: gasification solids bucket elevator: 3,000 cfm; gasification solids transfer tower: 3,000 cfm; gasification solids load-out system: 10,000 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

S-7616-23-0 (Sulfur Recovery and Tail Gas Compression System)

- Emission rates from the tail gas thermal oxidizer shall not exceed the following: NOx: 0.24 lb/MMBtu; CO: 0.20 lb/MMBtu; VOC: 0.0055 lb/MMBtu; PM10: 0.0076 lb/MMBtu. [District Rule 2201]

- SOx (as SO2) emissions from the tail gas thermal oxidizer shall not exceed 0.00204 lb/MMBtu for the disposal of SRU startup gas, 2.0 lb/hr for the disposal of the process vent gas, 75.0 lb/hr during plant shutdown for passivation, nor 125.0 lb/hr for presulfiding of catalyst. [District Rule 2201]

- The thermal oxidizer firing rate shall not exceed 13.0 MMBtu/hr (HHV) of natural gas from normal operation (for the disposal of process vent gas). Pre-startup firing of natural gas in the SRU reactor furnace for system warmup, with the products of combustion vented to the thermal oxidizer, shall not exceed 80.0 MMBtu/hr (HHV). Likewise, post-shutdown firing of natural gas in the SRU for plant maintenance shall not exceed 80.0 MMBtu/hr (HHV). [District Rule 2201]

- Fugitive CO and SOx emission rate from the unit shall not exceed 2.7 lb-CO/day and 0.4 lb-SOx based on the component count, CO and SOx percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

- The VOC content of the gas in the following streams shall not exceed 10% by weight: sulfur, tail gas unit process gas. [District Rule 2201]

S-7616-24-0 (CO2 Recovery and Vent System)

- Emission rates from the vent stream shall not exceed 496.3 lb-CO/hour, 28.2 lb-VOC/hour, 10.6 lb-COS/hour, nor 6.0 lb-H2S/hour. Compliance with these rates shall be demonstrated by measuring the vent stream flowrate and the concentration of these constituents in the vent stream. [District Rule 2201]

- Vent stream concentration shall not exceed 1,000 ppm-CO, 44 ppm-VOC, 10 ppm-COS, nor 10 ppm-H2S. [District Rule 2201]

- Emission rates from the vent stream shall not exceed 11,911 lb-CO/day nor 677 lb-VOC/day. [District Rule 2201]

S-7616-25-0 (Auxiliary Boiler)

- Emissions from this unit, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 5.0 ppmvd @ 3% O2 or 0.006 lb/MMBtu, SOx (as SO2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50.8 ppmvd @ 3% O2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

- The maximum allowable heat input of the boiler shall not exceed 213 MMBtu/hr (HHV). [District Rule 2201]

S-7616-27-0 (Gasification Process Area Cooling Tower)

- Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]
- Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]
- Cooling tower circulation water flow rate shall not exceed 162,582 gallons per minute nor 81.10 billion gallons per calendar year. [District Rule 2201]
- PM10 emission rate from the cooling tower shall not exceed 87.9 lb/day. [District Rule 2201]
- Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

S-7616-28-0 (Air Separation Unit Cooling Tower)

- Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]
- Total dissolved solids (TDS) in circulating water shall not exceed 2,000 mg/liter. [District Rule 2201]
- Cooling tower circulation water flow rate shall not exceed 44,876 gallons per minute nor 22.4 billion gallons per calendar year. [District Rule 2201]
- PM10 emission rate from the cooling tower shall not exceed 5.4 lb/day. [District Rule 2201]
- Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

S-7616-29-0 (Power Block Cooling Tower)

- Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]
- Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]
- Cooling tower circulation water flow rate shall not exceed 95,500 gallons per minute nor 49.7 billion gallons per calendar year. [District Rule 2201]

- PM10 emission rate from the cooling tower shall not exceed 51.6 lb/day. [District Rule 2201]

- Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

S-7616-30-0 (Gasification Flare)

- Maximum amount of gas combusted in the flare during planned flaring shall not exceed any of the following: 21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; 43,434 MMBtu/yr of shifted gas. [District Rule 2201]

- Emissions from the flare, during the non-emergency combustion of natural gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; CO: 0.08 lb/MMBtu; or SOx: 0.00214 lb/MMBtu. [District Rule 2201]

- Emissions from the flare, during the non-emergency combustion of syngas and waste gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.008 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0015 lb/MMBtu; CO: 2.0 lb/MMBtu on unshifted syngas and 0.37 lb/MMBtu on shifted syngas; or SOx: 0.002 lb/MMBtu. [District Rule 2201]

- Emissions from planned flaring shall not exceed any of the following: NOx: 2,399.0 lb/day; SOx: 79.7 lb/day; PM10: 238.2 lb/day; CO: 18,282.5 lb/day; or VOC: 51.2 lb/day. [District Rule 2201]

- Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

S-7616-31-0 (Sulfur Recovery Unit Flare)

- During planned flaring events, no more than 36 MMBtu/hr shall be (plus no more than 0.3 MMBtu/hr for pilot gas). [District Rule 2201]

- Emissions from the flare shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

- SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 18.4 lb/hr during other non-emergency combustion. [District Rule 2201]

- Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

S-7616-32-0 (Rectisol Flare)

- Maximum amount of gas combusted in the flare shall not exceed 2,628 MMBtu/yr during pilot gas combustion, nor 3,440 MMBtu/day nor 17,200 MMBtu/yr during other non-emergency combustion. [District Rules 2201 and 2410]

- Emissions from the flare during pilot and other non-emergency operation shall not exceed any of the following: PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

- SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 15.0 lb/hr during other non-emergency combustion. [District Rule 2201]

- Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

- Emissions from heater, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu, SOx (as SO2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50 ppmvd @ 3% O2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

- Fugitive CO emission rate from the unit shall not exceed 0.7 lb/day based on the component count, CO percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

- The VOC content of the gas in the following streams shall not exceed 10% by weight: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, NO2, nitric acid (HNO3), PSA off gas, CO2 product and purification compressors, and urea CO2 compressor. [District Rule 2201]

S-7616-34-0 (Urea Unit)

- PM10 emissions shall not exceed any of the following emissions for the following operations: urea bucket elevator: 0.3 lb/day. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: urea bucket elevator: 1,500 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

S-7616-35-0 (Nitric Acid Unit)

- The nitric acid unit shall not discharge into the atmosphere any gases which contained NOx, expressed as NO2, in exceed of 0.20 lb-NOx per ton of nitric acid produced (24-hour rolling average, expressed as 100 percent nitric acid), except during commissioning. [District Rule 2201 and 40 CFR 60 Subpart Ga]

- NOx emissions from the nitric acid unit shall not exceed 100.2 lb-NOx/day, except during commissioning. [District Rule 2201]

- The ammonia slip emissions (NH3) shall not exceed either of the following limits: 1.0 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]

- N2O emission rate shall not exceed 0.54 lb-N2O per ton of HNO3 produced (based on an annual average). [District Rule 2410]

S-7616-36-0 (Ammonium Nitrate Unit)

- PM10 emissions from scrubber vent shall not exceed 0.20 lb-PM10/hr. [District Rule 2201]

- PM10 emission from scrubber vent shall not exceed 0.0075 lb-PM10 per ton of ammonium nitrate produced (based on an annual average). [District Rule 2201]

S-7616-37-0 (Urea Storage and Loadout System)

- PM10 emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 0.3 lb/day; urea transfer tower 2: 0.3 lb/day; urea transfer tower 3: 0.3 lb/day; urea transfer tower 4: 0.3 lb/day; urea transfer tower 5: 0.3 lb/day; urea loading building: 4.1 lb/day. [District Rule 2201]

- Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

- Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: urea transfer tower 1: 1,500 cfm; urea transfer tower 2: 1,500 cfm; urea transfer tower 3: 1,500 cfm; urea transfer tower 4: 1,500 cfm; urea transfer tower 5: 1,500 cfm; urea loading building: 20,000 cfm. [District Rule 2201]

- Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

S-7616-38-0 (Emergency Engine Powering Electrical Generator)

- Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

S-7616-39-0 (Emergency Engine Powering Electrical Generator)

- Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

- Emissions from this IC engine shall not exceed any of the following limits: 1.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.015 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

E. Compliance Assurance

1. Source Testing

S-7616-26-0 (Combustion Turbine Generator)

District Rule 4703 requires NO_X and CO emission testing on an annual basis. The District Source Test Policy (APR 1705) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler and filter are performing. Therefore, source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be required within 120 days of initial operation and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for the CTG initially and not less than every seven years thereafter. If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then source testing to measure startup NO_X and CO mass emission rates shall be conducted at least once every 12

months. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

The CTG will be equipped with CEMs for NO_X, CO, and O_2. The CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires fuel nitrogen content testing. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to fuel nitrogen content testing.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

S-7616-38-0 (Emergency Engines Powering Electrical Generator)
S-7616-39-0 (Emergency Engines Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

Pursuant to District Policy APR 1705, source testing is not required for emergency IC engines to demonstrate compliance with Rule 2201.

S-7616-17-0 (Railcar Unloading and Transfer System)
S-7616-18-0 (Truck Unloading and Transfer System)
S-7616-19-0 (Feedstock Storage, Blending, and Reclaim System)
S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)
S-7616-22-0 (Gasification Solids Material Handling System)
S-7616-37-0 (Urea Storage and Loadout System)

Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

S-7616-24-0 (CO2 Recovery and Vent System)

Permittee shall conduct an initial speciated hazardous air pollutants (HAPs) and total VOC source test for the CO2 recovery and vent system by District witnessed sampling of vented stream by a qualified independent source test firm. The permittee shall determine the total HAPs emissions rate, the single highest HAP emission rate, and the VOC mass emission during the source test. Initial compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates determined

during initial compliance source testing and the correlation between VOC emissions and HAP(s). The vent stream composition of CO, VOC, H2S, COS, and the HAPs identified in the initial speciated HAPs and total VOC source test, shall be measured during each venting occurrence exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District in writing.

S-7616-25-0 (Natural-Gas Fired Auxiliary Boiler)
S-7616-33-0 (Ammonia Synthesis Startup Heater)

The units shall be tested for compliance with the NOx and CO emissions limits at least once every twelve months. After demonstrating compliance on two consecutive annual source tests, the unit shall be tested not less than once every thirty-six months.

S-7616-27-0, -28-0, and -29-0 (Cooling Towers)

Compliance with the total dissolved solids (TDS) limit in the circulating water shall be determined by an independent laboratory within 60 days of initial operation and quarterly thereafter.

S-7616-36-0 (Ammonium Nitrate Unit)

Source testing to quantify PM10 emissions from scrubber vent, expressed as lb-PM10/hr, and scrubber PM10 control efficiency shall be conducted within 60 days after initial start-up with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted, and once every twelve months thereafter.

2. Monitoring

S-7616-26-0 (Combustion Turbine Generator)

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during startup and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this DOC. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel nitrogen content. As stated in the Subpart KKKK compliance section of this document, the District will allow the annual NO_X source test to substitute for this requirement.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0

gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require initial weekly testing for eight consecutive weeks and semi-annual fuel sulfur content testing thereafter if the fuel sulfur content remains below 1.0 gr/scf. Therefore, fuel sulfur content testing is required.

S-7616-27-0 (Gasification Process Area Cooling Tower)
S-7616-28-0 (Air Separation Unit Cooling Tower)
S-7616-29-0 (Power Block Cooling Tower)

District Rule 7012 requires hexavalent chromium concentration testing to be conducted at least once every six (6) months for non-wooden cooling towers subject to Section 5.2.3 of the rule. Since the cooling tower has never had hexavalent chromium containing compounds added to the circulating water, this unit is exempt from the monitoring requirements of the rule. Therefore, no monitoring will be required for these units.

S-7616-23-0 (Sulfur Recovery System)

The operation shall include a continuously recording H2S monitor at the incinerator inlet (on the TGU absorber overhead) and shall include an incinerator with continuously recording SO2 and O2 monitors.

S-7616-25-0 (Natural-Gas Fired Auxiliary Boiler)
S-7616-33-0 (Ammonia Synthesis Startup Heater)

The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications.

S-7616-35-0 (Nitric Acid Unit)

The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The applicant is required to keep records of parameter for many of the emission units. Refer to section VIII.E.2 of this document for a discussion of the parameters that will be monitored.

4. Reporting

S-7616-26-0 (Combustion Turbine Generator)

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedances of the NO_X emission limit. Such reporting will be required.

S-7616-27-0, -28-0, and -29-0 (Cooling Towers)

District Rule 7012 requires the facility submit a compliance plan to the APCO at least 90 days before the newly constructed cooling tower is operated. Such reporting will be required.

S-7616-23-0 (Sulfur Recovery System)

For the SRU, the operator shall report all 3-hour periods during which the average concentration of H2S as measured by the H2S continuous monitoring system exceeds 10 ppm (dry basis, zero percent excess air).

S-7616-24-0 (CO2 Recovery and Vent System)

Periods of venting from the CO2 recovery and vent system shall be reported to the District by the following working day, including the duration of the venting event and the vent gas composition observed.

S-7616-30-0, -31-0, and -32-0 (Flares)

The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned.

Also, periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating.

S-7616-35-0 (Nitric Acid Unit)

40 CFR 60 Subpart Ga, requires the permittee to submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the EPA Administrator at the appropriate address as shown in 40 CFR 60.4. The permittee shall report to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard: (1) Time period; (2) NOx emission rates (lb/ton of acid produced); (3) Reasons for noncompliance with the emissions standard; and (4) Description of corrective actions taken. The permittee shall also report the following whenever they occur: (1) Times when the pollutant concentration exceeded full span

of the NOx pollutant monitoring equipment; and (2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

Additionally, the permittee shall report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications. If a malfunction occurred during the reporting period, the permittee must submit a report that contains the following: (1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded; (2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with §60.11(d), including actions taken to correct a malfunction.

F. Ambient Air Quality Analysis

Section 4.14.1 of this Rule requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to the Refined AAQA Results in Section 8.2.9.2 of Appendix K (Ambient Air Quality Impact and Health Risk Report). The results of the refined AAQS analysis for HECA's operations are shown in Table 8-5. The analysis demonstrates that emissions from HECA will not cause or contribute to exceedance of a NAAQS and/or CAAQS for any affected pollutant.

The District also considered additional information to ensure that the Project would not be responsible for causing a new NAAQS and/or CAAQS exceedance outside this modeling area. The District also considered the emission reduction credits being surrendered by the applicant if the project exceeds any NAAQS, CAAQS, and SIL threshold when making its determination. The District concludes the Project's expected emissions would not create any new NAAQS and/or CAAQS exceedances.

As noted in Table 8-5, all pollutants except PM2.5 24-hour and annual are below either the NAAQS/CAAQS or the SIL thresholds. As per District Rule 2201 section 4.14.1, mitigation may be considered when evaluating a projects ambient air quality impact. To ensure, to the maximum extent possible, that a facility's emissions do not adversely impact air quality the District requires that it fully offsets any air quality impact. Therefore, since emissions from PM2.5 24-hour and annual exceed the NAAQS/CAAQS and SIL thresholds HECA will be required to fully offset, down to zero, their PM2.5 emissions - see application review Rule 2201 compliance discussion.

G. Alternative Siting

Section 4.15.1 of this rule requires the applicant to prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the Public Resources Code (CEQA) for those sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the Federal Clean Air Act.

The California Energy Commission (CEC) will be preparing an equivalent analysis as part of its

preliminary staff assessment of the project, prior to the final decision of by the CEC on the project.

H. Compliance Certification

Section 4.15.2 of this rule requires the owner of a new Major Source or a source undergoing a Major Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. Hydrogen Energy California, LLC and SCS Energy California, LLC do not own or operate any facilities in the State of California; therefore, proof of compliance with applicable federal, state, and SJVAPCD emission limits, and applicable environmental standards, is not applicable.

Rule 2410 – Prevention of Significant Deterioration

As demonstrated in Section VII.C.9 above, the project is subject to the requirements of Rule 2410 for NO2, CO, PM, PM10, and GHGs.

Below is a listing of the requirements of Rule 2410, and demonstration that compliance with the requirements is expected.

A. Best Available Control Technology (BACT)

NOx, CO, and PM10 emissions

The Rule 2410 requirement for BACT is less stringent than the Rule 2201 requirement for BACT. In Rule 2410, BACT is defined as an emission limit based on the maximum degree of emission reduction, as determined on a case by case basis after taking into account energy, environmental, economic impacts, and other costs. For Rule 2410 purposes, costs can be taken into account even of the control technology has been achieved in practice for similar units.

In Rule 2201 BACT is defined as the most stringent control that either 1) achieved in practice for such class and category of source (regardless of cost), 2) contained in an EPA approved SIP for such lass and category of source, 2) contained in a Federal New Source Performance Standard, or 4) any emission technique that is both technologically feasible and cost effective. This BACT definition does not allow a consideration of costs for control techniques that have been achieved in practice.

As Rule 2201 required BACT for NOx, CO, and PM10, the BACT requirements of Rule 2410 are satisfied by compliance with the Rule 2201 BACT requirement.

PM emissions

As discussed in Section VII, all particulate matter emissions from the stationary source are PM10 and smaller due to the use of baghouses on all solids material handling operations and

combustion of gaseous fuels. As Rule 2201 required BACT for PM10, the BACT requirements of Rule 2410 for PM are satisfied by compliance with the Rule 2201 PM10 BACT requirement.

GHG emissions

GHG BACT requirements for this project are discussed in the GHG BACT discussion in Appendix I of this evaluation, with the specific requirements summarized in Table 7 of that discussion.

Pursuant to the GHG BACT discussion, BACT for GHG will be satisfied with the following:

S-7616 (Facilitywide requirement)

GHG:

- The facility CO2e potential emissions will be limited to 593,965 tons-CO2e/yr. The permittee will be required to monitor the facility's CO2e and maintain such records onsite.

S-7616-26-0 (Combustion Turbine Generator)

GHG:

- Capture of 90% of the pre-combustion CO2 through carbon sequestration and firing on hydrogen-rich fuel
- Energy-efficient turbine design
- Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

S-7616-24-0 (CO2 Recovery and Vent System)

GHG:

- Capture, compression, and transportation of the CO2 stream in a pipeline for injection (during normal operation); venting of CO2 stream when injection system is unavailable due to upset condition with such venting equivalent to cumulative venting periods not exceeding 504 hours (or its equivalent flowrate of 193,394 tons of CO2) per rolling 12-month period; and the use of good operating practices on the CO2 and transportation system.

S-7616-25-0 (Auxiliary Boiler)

GHG:

- Limited operation (annual fuel firing rate limited to 466 billion Btu per year)
- Firing on a lower-carbon fuel (PUC-quality natural gas)
- Energy-efficiency measures (economizer and condensate recovery)
- Tuning the boiler twice per calendar year

S-7616-35-0 (Nitric Acid Unit)

GHG:

- Tertiary control (catalytic decomposition) and N2O emission rate limited to 0.54 lb-N2O/ton of HNO3 produced

S-7616-23-0 (Tail Gas Thermal Oxidizer)

GHG:

- Firing on PUC-quality natural gas
- Sulfur recovery unit startup venting limited to 48 hours per calendar year

S-7616-30-0, -31-0, and -32-0 (Flares)

GHG:

- Minimization of flaring and the preparation of a flare minimization plan.
- Limited venting

S-7616-33-0 (Ammonia Synthesis Plant Startup Heater)

GHG:

- Intermittent use of the startup heater (annual firing rate limited to 7.84 billion Btu/yr)
- Firing on PUC-quality natural gas

S-7616-34-0 (Urea Absorber)

GHG:

- Implementation of good operating practices.

S-7616-38, -39-0 (Diesel-Fired Emergency Engines Powering Electrical Generators)

GHG:

- Limited operation (limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 50 hours per calendar year)
- Installation the latest EPA Tier certification level

S-7616-40-0 (Diesel-Fired Emergency Engines Powering Firewater Pump)

GHG:

- Limited operation (limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 100 hours per calendar year)
- Installation the latest EPA Tier certification level

S-7616-21-0, -23-0, -33-0 (Fugitive Emissions – Gasification Block and Manufacturing Complex)

GHG:

- Leak detection and repair (LDAR) program

Circuit Breakers

GHG: [40]

- Use of state-of-the art circuit breakers that use SF6 technology with a leak detection system

B. Other Rule 2410 Requirements

[40] Circuit breakers are not subject to District permitting requirements, but the GHG BACT requirement conditions regarding circuit breakers will be included on S-7616-26.

The project's ambient air quality impact analysis and additional analysis including visibility, soils, vegetation, and growth are discussed in the Ambient Air Quality Impact and Health Risk Report for District Rule 2201 (New Source Review), District Rule 4102 (Nuisance) and District Rule 2410 (Prevention of Significant Deterioration), which is found in Appendix K (Ambient Air Quality Impact and Health Risk Assessment Report).

Based on this analysis, Compliance with the requirements of Rule 2410 is expected.

Rule 2520 - Federally Mandated Operating Permits

Since this facility's emissions exceed the major source thresholds of District Rule 2201, this facility is a major source. Pursuant to Rule 2520 Section 5.1, and as required by DOC condition, the facility will have up to 12 months from the date of DOC issuance to either submit a Title V Application or comply with District Rule 2530 (Federally Enforceable Potential to Emit).

- Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 - Acid Rain Program

The proposed CTG is subject to the acid rain program as a phase II unit, i.e. it will be installed after 11/15/90 and it has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application to EPA at least 24 months before the date the unit expects to generate electricity.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

Proposed Rule 2540 Condition:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 - Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the analysis for Non-criteria pollutants/HAPs as shown in Appendix H.

Non-criteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source

Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[41]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). Any pollutant that may be emitted from the project and is on the federal New Source Review List and the federal Clean Air Act list has been evaluated.

As is shown in the Hazardous Air Pollutant Summary in Appendix H (Table 5-2 HECA Total Toxic Air Contaminant Annual Emission Rates), emissions of each individual HAP are below 10 tons per year and total HAP emissions for the stationary source are below 25 tons per year. Therefore, this stationary source will not be a major air toxics source and the provisions of this rule do not apply.

To ensure this source is not a major air toxics source, the following conditions will be listed on the DOC:

- Hazardous Air Pollutant (HAP) emissions for the stationary source shall not exceed 25 tpy all HAPs nor 10 tpy for any single HAP. [District Rule 4002]

Additionally, units S-7616-24 and -26 are the primary contributors of HAPs, the following conditions will be placed on S-7616-24 and -26:

S-7616-24-0 (CO2 Recovery and Vent System)

- Permittee shall conduct an initial speciated HAPs and total VOC source test for the CO2 recovery and vent system by District witnessed sampling of vented stream by a qualified independent source test firm. The permittee shall determine the total HAPs emissions rate, the single highest HAP emission rate, and the VOC mass emission during the source test. Initial compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates determined during initial compliance source testing and the correlation between VOC emissions and HAP(s). Ongoing compliance shall be determined using mass flow and VOC sampling during venting occurrences as described in the condition below. [District Rule 4002]

- The vent stream composition of CO, VOC, H2S, COS, and the HAPs identified in the initial speciated HAPs and total VOC source test, shall be measured during each venting occurrence exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District in writing. [District Rule 2201]

S-7616-26-0 (Combustion Turbine Generator)

- Permittee shall conduct an initial speciated HAPs and total VOC source test for the combustion turbine generator by District witnessed in situ sampling of exhaust gases by a qualified

[41] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

independent source test firm. The permittee shall correlate the total HAPs emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the combustion gas turbine determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

Rule 4001 - New Source Performance Standards (NSPS)

40 CFR 60 – Subpart GG (Standards of Performance for Stationary Gas Turbines)

S-7616-26-0 (Combustion Turbine Generator)

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Therefore, the requirements of this subpart apply to the proposed CTG.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Therefore, the requirements of this subpart apply to the proposed CTG.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to the proposed turbine. Therefore, it is exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 – Subpart KKKK (Standards of Performance for Stationary Turbines)

S-7616-26-0 (Combustion Turbine Generator)

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. Therefore, the requirements of this subpart apply to the proposed CTG.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). Table 1 also states that new turbines firing fuel other than natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 42 ppmvd @ 15% O_2 or 1604 ng/J of useful output (1.3 lb/MWh).

The proposed combustion turbine generator's NO_X emission concentration will be limited to the following emissions limits:

NOx : 2.5 ppmvd @ 15% O2 (1-hour average) when firing on hydrogen-rich fuel and 4.0 ppmvd @ 15% O2 when firing on natural gas, except during startup/shutdown.

Therefore, the proposed turbine will be operating in compliance with the NO_X emission requirements of this subpart. The following condition will ensure continued compliance with the requirements of this section:

- During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 25.0 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 3.5 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 18.3 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 12.9 lb/hr; or SOx (as SO2) - 4.1 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- During normal operation (excluding startup and shutdown), emission rate from the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 4.4 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 0.6 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 3.2 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 1.4 lb/hr; or SOx (as SO2) - 0.9 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that a turbine located in a continental area must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu)

heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

The applicant is proposing to burn natural gas fuel with a maximum sulfur content of 0.75 grain/ 100 scf (12 ppm-SO2 or 0.0021 lb-SO2/MMBtu), and hydrogen-rich gas with a maximum sulfur content of 10 ppm-SO2. Therefore, the proposed turbine will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- This unit shall exclusively burn PUC-regulated natural gas with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas, hydrogen-rich fuel with a sulfur content no greater than 10 ppmv, or a combination of both fuels. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, the permittee must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Paragraph (b) states that alternatively, an operator may use continuous emission monitoring, as follows:

(1) Install, certify, maintain and operate a continuous emissions monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
(2) For units complying with the output-based standard, install, calibrate, maintain and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
(3) For units complying with the output based standard, install, calibrate, maintain and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/hr).

The applicant proposes a turbine that utilizes steam injection. They are proposing to install, certify, maintain and operate a CEMS consisting of a NO_X monitor and an O_2 monitor to determine hourly NO_X emission rate in ppm. They are not proposing to comply with the output-based NO_X emission standards listed in Table 1. Therefore, the proposed CEMS satisfies the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

This section specifies the requirements for units not equipped with water or steam injection. As discussed above, the applicant is proposing to use steam injection to reduce NO_X emissions in each of these turbines. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

The permittee will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, the permittee is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution

procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

HECA is proposing to monitor the NO_X emissions rates from the turbine with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stack. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

Section 60.4355 – Parameter Monitoring Plan:

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, HECA is proposing to install CEMS on the turbine that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. One of the following sources of information must be used to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

HECA is proposing to operate the turbine on natural gas fuel with a maximum sulfur content of 0.75 grain/ 100 scf (12 ppm-SO2 or 0.0021 lb-SO2/MMBtu), and hydrogen-rich gas with a maximum sulfur content of 10 ppm-SO2. The following condition will ensure continued compliance with the requirements of this section:

- This unit shall exclusively burn PUC-regulated natural gas with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas, hydrogen-rich fuel with a sulfur content no greater than 10 ppmv, or a combination of both fuels. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in the turbine, the District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. HECA is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for this turbine. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each natural gas fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, HECA is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEMS:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or

megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. HECA is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

The permittee will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbine will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for the turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. The permittee is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set forth the requirements for the methods that are to be used during source testing.

The permittee will be required to source test the exhaust of the turbine within 120 days of initial startup and at least once every 12 months thereafter. The permittee will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). The permittee has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets forth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, the permittee is proposing to install a CEMS system to monitor the NO_X emissions from the turbine and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415 – SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that may be used to conduct the performance tests.

(1) If the applicant chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, the applicant may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples should be analyzed for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

The permittee shall periodically determine the sulfur content of the fuel combusted in the turbine when valid purchase contracts, tariff sheets or transportation contract are not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. HECA is not proposing to measure the SO_2 in the exhaust stream of the turbine. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into the DOC in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

40 CFR 60 – Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)

S-7616-25-0 (Auxiliary Boiler)

New Source Performance Standards, Code of Federal Regulations 40 part 60, Subpart Db (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) applies only to units with heat input capacity of greater than 100 MMBtu/hr.

The new 230 MMBtu/hr[42] natural gas-fired auxiliary boiler (S-7616-25-0) in this project is subject to the New Source Performance Standards, Code of Federal Regulations 40 part 60, Subpart Db (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units).

PM and SOx Standards:

Sections 60.42b and 60.43b list requirements for Particulate Matter (PM) and SO_X emissions. The PM and SO_X requirements are applicable for facilities that operate coal or oil fired steam

[42] The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 230 MMBtu/hour (HHV). However the heat input of the unit will be limited and maintained at or below 213 MMBtu/hour.

generators. The applicant is only proposing to operate the new boiler on PUC-quality natural gas. Therefore, the PM and SOx standards of this subpart do not apply.

NOx Standards and Testing:

Section 60.44b (a) states that the owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil or natural gas shall not cause to be discharged into the atmosphere from the affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the specified limits.

Section 60.44b (a) states that, for low heat and high release rate units, the natural gas-fired emission limit is 0.10 lb-NOx/MMBtu and 0.20 lb-NOx/MMBtu, respectively. The permittee has proposed a boiler that will be limited to 0.0060 lb-NOx/MMBtu (5 ppmvd-NOx @ 3% O2). Section 60.44b (h) states the emission limit in Section 60.44b (a) shall apply at all times, including periods of startup, shutdown, or malfunction. Section 60.44b (i) states that, except provided under paragraph 60.44b (j), compliance with the emission limits in Section 60.44b (a) is determined on a 30-day rolling average.

Section 60.46b (c) states that compliance with the NOx limits in Section 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of section 60.46b, as applicable.

Section 60.46b (e) states that, to determine compliance with the emission limits for NOx required under Section 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under Section 60.8 using the continuous emission monitoring system for monitoring NOx under 60.48b.

NOx Monitoring

Section 60.48b (b) states that, except as provided under paragraphs (g), (h), and (i) of section 60.48b, the owner or operator of an affected facility subject to the NOx standard under Section 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of Section 60.48b.

(b)(1) Install, calibrate, maintain, and operate a continuous monitoring system (CEMs), and record the output of the system, of measuring NOx emissions discharged to the atmosphere

Section 60.48b (g) states that the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and which has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), and (f) of Section 60.48b, or
(2) Monitor steam generating unit operating conditions and predict NOx emission rates as specified in a plan submitted pursuant to Section 60.49b (c).

Section 60.48b (j) states that units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32

lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

Recordkeeping and Reporting

Section 60.49b (a)(1) states that the owner or operator of an affected facility shall submit notification of the date of initial startup, as provided by Section 60.7 and shall include the design heat input capacity and identification of the fuels to be combusted. The following condition will be added to the DOC to assure compliance with this section:

- Permittee shall comply with all applicable NSPS requirements, including monitoring, notification and reporting requirements as described in 40 CFR 60 Subparts A and Db. [District Rule 4001]

Section 60.49b (c) states that the owner or operator of each affected facility subject to the NOx standard of 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generator unit operating conditions under the provisions of 60.48b (g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under 60.48b (g)(2) and the records to be maintained under 60.49b (j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOx emission rates (lb/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e. ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e. flue gas oxygen level);
(2) Include the data and information that the owner or operator used to identify the relationship between NOx emission rates and these operating conditions;
(3) Identify how these operating condition, including steam generating unit load, will be monitored under 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedure or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under 60.49b(j).

If the plan is approved, the owner or operator shall maintain records of predicted NOx emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The following condition will be added to the DOC:

- Permittee shall submit to the EPA Regional Administrator for approval a plan that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b (j). This plan shall be submitted to the EPA Regional Administrator for approval within 360 days of the initial startup of the affected facility. [District Rule 4001]

Conclusion:

The new boiler complies with Subpart Db requirements. The following condition will be added to the DOC to ensure compliance:

- Permittee shall comply with all applicable NSPS requirements, including monitoring, notification and reporting requirements as described in 40 CFR 60 Subparts A and Db. [District Rule 4001]

- Permittee shall submit to the EPA Regional Administrator for approval a plan that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b (j). This plan shall be submitted to the EPA Regional Administrator for approval within 360 days of the initial startup of the affected facility. [District Rule 4001]

Therefore, compliance with the requirements of this rule is expected.

40 CFR 60 – Subpart G (Standards of Performance for Nitric Acid Plants)

This subpart applies to each nitric acid production unit that commences construction or modification after August 17, 1971, and on or before October 14, 2011. Any facility that commences construction or modification after October 14, 2011 is subject to Subpart Ga of this part. Therefore, Subpart Ga, which is discussed below, will apply to the nitric acid unit (S-7616-35-0) instead.

40 CFR 60 – Subpart Ga (Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011)

S-7616-35-0 (Nitric Acid Unit)

Section 60.70a - Applicability and designation of affected facility:

The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility. This subpart applies to any nitric acid production unit that commences construction or modification after October 14, 2011.

Thus, the provisions of this subpart are applicable to proposed nitric acid unit (S-7616-35-0).

Section 60.72a - Standards:

This section states that on and after the date on which the performance test required to be conducted by §60.73a(e) is completed, the nitric acid unit shall not discharge into the atmosphere from any affected facility any gases which contain NO_X, expressed as NO_2, in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times.

Per information submitted by the applicant, the nitric acid unit will discharge NOx emissions at a rate no more than 0.20 lb-NOx per ton of nitric acid produced (expressed as 100 percent nitric acid), averaged over a 24-hour rolling hour period, which complies with the applicable standard. The following condition will assure compliance with this section:

- The nitric acid unit shall not discharge into the atmosphere any gases which contained NOx, expressed as NO2, in exceed of 0.20 lb-NOx per ton of nitric acid produced (24-hour rolling average, expressed as 100 percent nitric acid). [District Rule 2201 and 40 CFR 60 Subpart Ga]

- The nitric acid plant shall comply with the requirements of 40 CFR Part 60, Subpart Ga. [40 CFR 60 Subpart Ga]

Section 60.73a - Emissions testing and monitoring:

General emissions monitoring requirements:

This section requires the permittee to install and operate a NO_X concentration (ppmv) continuous emissions monitoring system (CEMS). The permittee must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO_X concentration and stack gas flow rate, the permittee shall determine hourly NO_X emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). The permittee must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction.

- The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60. [District Rule 2201 and 40 CFR 60 Subpart Ga]

- The permittee shall install, calibrate, maintain, and operate a stack gas flow rate monitoring system. [40 CFR 60 Subpart Ga]

- The permittee shall determine hourly NOx emissions rate and calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). [40 CFR 60 Subpart Ga]

- The CEMS shall be in continuous operation during all operating periods including unit startup and shutdown, and malfunction. [40 CFR 60 Subpart Ga]

- The permittee shall determine hourly NOx emissions rate and calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). [40 CFR 60 Subpart Ga]

Nitrogen oxides concentration continuous emissions monitoring system:

This section also states that the permittee must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of this part. The permittee must use cylinder gas audits to fulfill the quarterly auditing requirement.

For the NOx concentration CEMS, the permittee must use a span value, as defined in Performance Specification 2, Section 3.11, of Appendix B of this part, of 500 ppmv (as NO2). If the NOx concentrations emitted is higher than 600 ppmv (e.g., during startup or shutdown periods), the permittee must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NOx emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods.

Compliance with this section will be better assured with the following conditions:

- The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60. [District Rule 2201 and 40 CFR 60 Subpart Ga]

- The permittee must use cylinder gas audits to fulfill the quarterly auditing requirement. [40 CFR 60 Subpart Ga]

- For the NOx concentration CEMS, the permittee must use a span value, as defined in Performance Specification 2, Section 3.11, of Appendix B of this part, of 500 ppmv (as NO2). If the NOx concentrations emitted is higher than 600 ppmv (e.g., during startup or shutdown periods), the permittee must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NOx emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods. [40 CFR 60 Subpart Ga]

For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, the permittee shall use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 of this part; EPA Reference Method 320 of Appendix A of part 63 of this chapter; or ASTM D6348–03 (incorporated by reference, see §60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of this section, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of this part) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of this part).

Compliance with this section will be better assured with the following conditions:

- The permittee shall perform a relative accuracy test audit (RATA) for the NOx CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters.

The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080 and 40 CFR 60 Subpart Ga]

Determining NOx mass emissions rate values:

The permittee must use the NOx concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NOx/ton of acid produced expressed as 100 percent nitric acid).

The permittee must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NOx to produce data in units of mass rate (e.g., lb/hr) of NOx on an hourly basis. The permittee must operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of §60.13 and Performance Specification 6 of Appendix B of this part.

Compliance with this section will be better assured with the following conditions:

- The permittee must operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of §60.13 and Performance Specification 6 of Appendix B of part 60 and the specifications of Section 60.73a (Subpart Ga). [40 CFR 60 Subpart Ga]

Initial performance testing:

The permittee must conduct an initial performance test to demonstrate compliance with the NOx emissions limit under §60.72a(a) beginning in the calendar month following initial certification of the NOx and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NOx average concentration, mass flow rate recorded with the certified NOx concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. The permittee must assure that the CERMS meets all of the data quality assurance requirements as per §60.13 and Appendix F, Procedure 1, of this part and you must use the data from the continuous emissions rate monitoring system (CERMS) for this compliance determination.

Compliance with this section is better assured with this condition:

- The permittee must conduct an initial performance test to demonstrate compliance with the NOx emissions limit under §60.72a(a) beginning in the calendar month following initial certification of the NOx and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NOx average concentration, mass flow rate recorded with the certified NOx concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described

above. The permittee must assure that the CERMS meets all of the data quality assurance requirements as per §60.13 and Appendix F, Procedure 1, of this part and you must use the data from the continuous emissions rate monitoring system (CERMS) for this compliance determination. [40 CFR 60 Subpart Ga]

Section 60.74a - Affirmative defense for violations of emission standards during malfunction:

This section describes how a permittee may assert an affirmative defense to a claim for civil penalties for violation of standards set forth in section 60.72a, where such violations are caused by malfunction as defined in 40 CFR 60.2.

Section 60.75a - Calculations:

This section requires that the permittee calculate the 30 operating day rolling arithmetic average emission rate in units of the applicable emissions standard (lb-NOx/ton 100 percent acid produced) at the end of each operating day using all the quality assured hourly average CEMS data for the previous 30 operating days.

Since the BACT requirement for the nitric unit specifies compliance with a 24-hour rolling average limit, the following condition will assure compliance with the requirements of this section and BACT:

- The permittee shall calculate the 24-hour day rolling arithmetic average emission rate in units of the applicable emissions standard (lb-NOx/ton 100 percent acid produced) at the end of each operating day using all the quality assured hourly average CEMS data for the previous 24 operating hours according to the procedures specified in Section 60.75a. [District Rule 2201 and 40 CFR 60 Subpart Ga]

Section 60.76a - Recordkeeping:

According to this section, for the NOx emissions rate, the permittee must keep records for and results of the performance evaluations of the continuous emissions monitoring systems.

The permittee must maintain records of the following information for each 30 operating day period:
(1) Hours of operation.
(2) Production rate of nitric acid, expressed as 100 percent nitric acid.
(3) 24 operating hour average NOx emissions rate values.

The following condition will assure compliance with this section:

- The permittee shall maintain records of the following information for each operating day period: (1) hours of operation; (2) production rate of nitric acid, expressed as 100 percent nitric acid; (3) 24-hour average NOx emissions rate values. [District Rule 2201 and 40 CFR 60 Subpart Ga]

The permittee must also maintain records of the following time periods:

(1) Times when the equipment is not in compliance with the emissions standards.
(2) Times when the pollutant concentration exceeded full span of the NOx monitoring equipment.
(3) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

These requirements will be satisfied with this condition:

- The permittee shall maintain records of the following time periods: (1) times when the equipment is not in compliance with the emissions standards; (2) times when the pollutant concentration exceeded full span of the NOx monitoring equipment; (3) times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [40 CFR 60 Subpart Ga]

The permittee must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken.

The permittee must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications.

For each malfunction, the permittee must maintain records of the following information:
(1) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with §60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

These requirements will be satisfied with this condition:

- The permittee shall maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications. For each malfunction, the permittee shall maintain records of the following information: (1) records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment; (2) records of actions taken during periods of malfunction to minimize emissions in accordance with section 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR 60 Subpart Ga]

<u>Section 60.77a - Reporting:</u>

This section requires the permittee to submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the Administrator at the appropriate address as shown in 40 CFR 60.4.

The following information must be reported to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard:
(1) Time period;

(2) NOx emission rates (lb/ton of acid produced);
(3) Reasons for noncompliance with the emissions standard; and
(4) Description of corrective actions taken.

The permittee must also report the following whenever they occur:
(1) Times when the pollutant concentration exceeded full span of the NOx pollutant monitoring equipment.
(2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

These requirements will be satisfied with this condition:

- The permittee to submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the Administrator at the appropriate address as shown in 40 CFR 60.4. The permittee shall report to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard: (1) Time period; (2) NOx emission rates (lb/ton of acid produced); (3) Reasons for noncompliance with the emissions standard; and (4) Description of corrective actions taken. The permittee shall also report the following whenever they occur: (1) Times when the pollutant concentration exceeded full span of the NOx pollutant monitoring equipment; and (2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [40 CFR 60 Subpart Ga]

The permittee must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications.

These requirements will be satisfied with this condition:

- The permittee shall report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications. [40 CFR 60 Subpart Ga]

Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, the permittee must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/SSL/cdx/EPA_Home.asp). The permittee must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE.

These requirements will be satisfied with this condition:

- Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, the permittee must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX)

(https://cdx.epa.gov/SSL/cdx/EPA_Home.asp) in the format specified in 40 CFR 60 Subpart Ga, Section 60.77a. [40 CFR 60 Subpart Ga]

If a malfunction occurred during the reporting period, the permittee must submit a report that contains the following:

(1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.
(2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with §60.11(d), including actions taken to correct a malfunction.

These requirements will be satisfied with this condition:

- If a malfunction occurred during the reporting period, the permittee must submit a report that contains the following: (1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded; (2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with §60.11(d), including actions taken to correct a malfunction. [40 CFR 60 Subpart Ga]

Therefore, compliance with Subpart Ga is expected.

40 CFR 60 – Subpart Y (Standards of Performance for Coal Preparation and Processing Plants)

S-7616-17-0 (Railcar Unloading and Transfer System)
S-7616-18-0 (Truck Unloading and Transfer System)
S-7616-19-0 (Feedstock Storage, Blending, and Reclaim System)
S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)

New Source Performance Standards, Code of Federal Regulations 40 part 60, Subpart Y (Standards of Performance for Coal Preparation and Processing Plants) applies to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day. The HECA facility will be authorized to amounts greater than this value for each of the operations identified above.

Section 60.250 - Applicability and designation of affected facility:

(d) The provisions in §60.251 - Definitions, §60.252(b)(1) through (3), and (c) – Standards for thermal dryers; §60.253(b) – Standards for pneumatic coal-cleaning equipment; §60.254(b) and (c) – Standard for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles; §60.255(b) through (h) – Performance tests and other compliance requirements; §60.256(b) and (c) – Continuous monitoring requirements; §60.257 – Test methods and procedures; and §60.258 – Reporting and recordkeeping of this subpart are

applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles. This operation will commence construction after this applicable date, and it will consist of coal processing and conveying equipment and coal storage systems.

Section 60.252 - Standards for thermal dryers:

Section 60.251 (r)(2) defines a thermal dryer for units constructed, reconstructed, or modified after May 27, 2009 as "any facility which the moisture content of the coal is reduced by either contact with a heater gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heater transfer medium." The proposed feedstock dryer meets the definition of a thermal dryer.

Section 60.252 (c) states that "thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart."

The proposed feedstock dryer (S-7616-20) receives all of its thermal input from the treated exhaust of the combustion turbine generator/heat recovery steam generator (S-7616-26-0) which is subject to 40 CFR Part 60 Subpart KKKK (Standards of Performance for Stationary Turbines). Therefore, the requirements of section 60.252 do not apply to S-7616-20 per Section 60.252 (c).

Section 60.254 - Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles:

Section 60.254 (b) states that on and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

Section 60.254 (b)(1) states that except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater. The proposed operation has conditions prohibiting visible emissions (5 percent opacity), so this requirement is satisfied. The following conditions will ensure compliance with this section:

- All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

- Each dust collector shall be equipped with dust-tight (no visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

Section 60.254 (b)(2) states that the owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf). The exhaust PM10 emission concentration rate will not exceed 0.001 gr/dscf from any of the dust collectors, so this requirement is satisfied. The following condition will ensure compliance with this section.

- Particulate matter emissions shall not exceed 0.001 grains/dscf in concentration from this operation. [District Rules 2201, 4001, and 40 CFR 60.254]

Section 60.254 (b)(3) states that equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section. Open storage pile is defined as "any facility, including storage area that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility". The proposed operation does not consist of open storage piles, so this section does not apply.

Section 60.254 (c) states that the owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section. The proposed operation does not consist of open storage piles, so this section does not apply.

Section 60.255 - Performance tests and other compliance requirements:

Section 60.255 (b)(1) states that an owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of §60.8 and the methods identified in §60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

Section 60.255 (b)(1) states that for each affected facility subject to a PM, SO_2, or combined NO_X and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance

test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

Therefore, the following conditions will be included on S-7616-17, -18, -19, and -20:

- Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

- Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

Section 60.255 (b)(2) states that for each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in §60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

Therefore, the following conditions will be included on S-7616-17, -18, -19, and -20:

- Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most

recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

- Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

- The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

Section 60.256 - Continuous monitoring requirements:

Section 60.256 (b) states that "the owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent." A mechanical vent is defined as "any vent that uses a powered mechanical drive (machine) to induce air flow." Since the operation does not include mechanical vents, the continuous monitoring requirements of this section do not apply.

Section 60.257 - Test methods and procedures:

Section 60.257 contains the test methods and procedures required for determine compliance with the applicability opacity standards and PM concentration limits. Those requirements are specified in the discussions above.

Section 60.258 - Reporting and recordkeeping:

Section 60.258 (a) states that the owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook requires the permittee to maintain records as specified in Section 60.258. The following condition will be included:

- Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

Section 60.258 (b) lists notification and recordkeeping requirements for those units subject to section 60.7(c). Section 60.7 (c) applies to those units served by continuous emission monitoring systems, and since this operation is not equipped with them, this section does not apply.

Section 60.258 (c) indicates that affected facilities subject to performance test requirements of section 60.8 shall submit the initial performance test results consistent with the provisions of

section 60.8, which requires submittal of test results within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

- Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

- Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

Conclusion:

Conditions will be incorporated into the DOC in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart Y is expected and no further discussion is required.

40 CFR 60 – Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

The following table demonstrates how the proposed engines will comply with the requirements of 40 CFR Part 60 Subpart IIII.

40 CFR 60 Subpart IIII Requirements for New Emergency IC Engines Powering Generators (2007 and Later Model Year)	Proposed Method of Compliance with 40 CFR 60 Subpart IIII Requirements
Engines must meet the appropriate Subpart IIII emission standards for new engines, based on the model year, size, and number of liters per cylinder.	The applicant has proposed the use of engine(s) that are certified to the latest EPA Tier Certification level for the applicable horsepower range, guaranteeing compliance with the emission standards of Subpart IIII.
Engines must be fired on 500 ppm sulfur content fuel or less, and fuel with a minimum centane index of 40 or a maximum aromatic content of 35 percent by volume. Starting in October 1, 2010, the maximum allowable sulfur fuel content will be lowered to 15 ppm.	The applicant has proposed the use of CARB certified diesel fuel, which meets all of the fuel requirements listed in Subpart IIII. An DOC condition enforcing this requirement was included earlier in this evaluation.

The operator/owner must install a non-resettable hour meter prior to startup of the engines.	The applicant has proposed to install a non-resettable hour meter. The following condition will be included in the DOC: This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]
Emergency engines may be operated for the purpose of maintenance and testing up to 100 hours per year. There is no limit on emergency use.	The Air Toxic Control Measure for Stationary Compression Ignition Engines (Stationary ATCM) limits the maintenance and testing to 50 hours/year for engines S-7616-38-0 and '-39-0, and to 100 hours/year for engine '-40-0. Thus, compliance is expected.
The owner/operator must operate and maintain the engines and any installed control devices according to the manufacturers written instructions.	The following condition will be included in the DOC: This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

§60.4200 - Applicability

This subpart is applicable to owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engine will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so no further discussion is required.

Rule 4002 - National Emission Standards for Hazardous Air Pollutants (NESHAPs)

Pursuant to Section 2.0, "All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;" therefore, the requirements of this rule applies to HECA. But there are no applicable requirements for a non-major HAPs source. HECA will conduct an initial speciated HAPS compliance source test to demonstrate that the facility is not a major HAPS source.

Proposed Rule 4002 Condition:

- Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

- Permittee shall conduct an initial speciated HAPS and total VOC source test for the combustion turbine generator, by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. The permittee shall correlate the total HAPs emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the combustion gas turbine determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Emissions (RICE)

Emergency engines are subject to this subpart if they are operated at a major or area source of Hazardous Air Pollutant (HAP) emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs. The proposed engines are new stationary RICE located at an area source of HAP emissions; therefore, these engines are subject to this Subpart.

40 CFR 63 Subpart ZZZZ requires the following engines to comply with 40 CFR 60 Subpart IIII:

1. New emergency engines located at area sources of HAPs
2. Emergency engines rated less than or equal to 500 bhp and located at major sources of HAPs

The proposed engines will be in compliance with 40 CFR 60 Subpart IIII (as explained in the Subpart IIII discussion above).

Additionally, 40 CFR 63 Subpart ZZZZ requires engines rated greater 500 bhp and located at major sources of HAPs to meet the notification requirements of §63.6645(h); however, that section only applies if an initial performance test is required. Since an initial performance test is not required for emergency engines, the notification requirement is not applicable.

Therefore, the proposed engines are expected to be in compliance with 40 CFR 63 Subpart ZZZZ.

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

This subpart establishes national emission limitation and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric generating units (EGUs) as defined

in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations. According to § 63.9984, the EGU must comply with the subpart upon startup of the EGU.

Since the proposed combustion turbine generator is fired on a synthetic fuel derived from coal, the unit is considered a coal-fired EGU, so it is subject to this subpart. *Coal* is defined in § 63.10042 as solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14), and coal refuse. *Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.*

Emission Limitations and Work Practice Standards:

Note that for purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, the proposed EGU is in the subcategory "integrated gasification combined cycle electric utility steam generating unit" or IGCC, which is defined in § 63.10042 as "an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation."

According to § 63.9991, the emission limit and work practice standard in Tables 1 through 3 that apply to the EGU. (Table 1 lists emission limits for new or reconstructed EGUs, while Table 2 applies to existing EGUs. Table 3 lists the work practice standards.)

General Requirements:

According to § 63.10005, for each of the affected EGUs, the permittee must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing.

Emission Limitations:

Per § 63.9991, for the subject new EGU, the emission limits of Table 1 below apply. (Table 2 limits, which apply to existing EGUs, do not apply.) The applicant has proposed to meet the filterable particulate matter limits of Table 1.

Table 1 allows the permittee the option to meet emission limits for filterable particulate matter, mercury, or the other emission surrogates for the project. The permittee intends to measure filterable particulate matter as a surrogate for metal toxics, and hydrogen chloride or sulfur dioxide as a surrogate for all toxic acid gases.

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh [4] 9.0E-2 lb/MWh [5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh.	
	Arsenic (As)	2.0E-2 lb/GWh.	
	Beryllium (Be)	1.0E-3 lb/GWh.	
	Cadmium (Cd)	2.0E-3 lb/GWh.	
	Chromium (Cr)	4.0E-2 lb/GWh.	
	Cobalt (Co)	4.0E-3 lb/GWh.	
	Lead (Pb)	9.0E-3 lb/GWh.	
	Manganese (Mn)	2.0E-2 lb/GWh.	
	Nickel (Ni)	7.0E-2 lb/GWh.	
	Selenium (Se)	3.0E-1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.

[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output

The permittee intends to measure filterable particulate matter as a surrogate for metal toxics, and hydrogen chloride or sulfur dioxide as a surrogate for all toxic acid gases. The Amended Application for Certification (AFC) Appendix E-3, page 6, presents the estimated IGCC emissions for the project (PM10 and SO2 from the heat recovery steam generator [HRSG] and

gasification feedstock dryer); and Appendix M presents the emissions of hydrogen chloride. The maximum combined HRSG and feedstock dryer emissions for the MATS constituents are shown below, as well as the ratio of emissions to power generated, using the minimum gross power production of 405 megawatts. These are the worst case conditions that assume 100 percent coal firing with the coal identified with the highest mercury levels.

Mercury Emission Calculations:

Based on 100% El Segundo Coal Feed:

Gasifier coal feed (dry basis) = 5023 tons/day (based on El Segundo coal)
Coal mercury concentration (dry basis) = 0.13 part per million by weight
Mercury in gasifier feed = 0.05442 lb/hr

Uncontrolled mercury in feedstock dryer exhaust (pro-rated MHI estimate) = 0.0028 lb/hr
Feedstock dryer mercury removal = 75 percent
Feedstock dryer mercury emission = 0.00069 lb/hr

Inlet mercury to syngas adsorber bed = 0.05442 – 0.00069 = 0.0537 lb/hr
Adsorber removal = 99 percent
Estimated HRSG flue gas mercury = 0.000537 lb/hr

Eighty-five percent of the HRSG mercury emissions will be exhausted through the HRSG stack and the remainder through the feedstock dryer stack. It is assumed that the mercury in HRSG gas sent to the dryer will be reduced by the dryer mercury removal system, thus:

Feedstock dryer mercury emission = 0.00069 lb/hr + (0.000537 lb/hr x 0.15 x 0.25)

HRSG mercury emission = 0.000537 lb/hr x 0.85

Summary

Feedstock dryer emission = 0.000710 lb/hr

HRSG emission = 0.000457

Total plant = 0.001167 lb/hr

Total mercury/gross power = 0.001167 lb/hr/405 MW × 1,000 MW/gigawatt = 0.00288 lb/gigawatt hour

HECA Emissions for Mercury and Air Toxics Standard (MATS) Compliance

Pollutant	**HECA Expected Emissions (HRSG plus Feedstock Dryer**		**MATS limit**
Filterable particulate matter	14.3 lb/hr	0.035 lb/MWh	0.07 lb/MWh
Hydrogen chloride	0.0372 lb/hr	9.2×10^{-5} lb/MWh	2.0×10^{-3} lb/MWh
Sulfur dioxide	5.0 lb/hr	0.012 lb/MWh	0.4 lb/MWh
Mercury	0.0011167 lb/hr	0.00288 lb/GWh	0.003 lb/GWh

Compliance with these requirements will be better assured with the following condition:

- During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack and the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: filterable particulate matter: 0.07 lb-MWh; hydrogen chloride: 2.0E-3 lb/MWh or sulfur dioxide: 0.4 lb/MWh; mercury: 0.003 lb/GWh based on a 30-day rolling average. [District Rules 2201 and 4002 and 40 CFR 63 Subpart UUUUU]

- Filterable particulate matter shall be measured using a continuous parametric monitoring system (PM CPMS). Sulfur dioxide shall be measured using SO2 CEMS. Mercury shall be measured using a sorbent trap monitoring system. Other approved measurement methods may be used with prior District approval. [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Work Practice Standards:

Per § 63.9991, the permittee shall comply with the following work practice standards:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

If your EGU is . . .	You must meet the following . . .
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup	You must operate all continuous monitoring system (CMS) during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

Compliance with these requirements will be better assured with the following condition:

- The permittee shall comply with the work practice standards for the CTG as specified in Table 3 to Subpart UUUUU of Part 63. The permittee shall conduct a tune-up of the CTG burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

- The permittee must operate all continuous monitoring system (CMS) for the CTG during startup. Startup means either the first-ever firing of fuel in a unit for the purpose of producing electricity, or the firing of fuel in a unit after a shutdown event for any purpose. Startup ends when any of the steam from the unit is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, permittee must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once permittee converts to firing coal, residual oil, or solid oil-derived fuel, permittee must engage all of the applicable control technologies except SCR. Permittee must start SCR system, if present, appropriately to comply with relevant standards applicable during normal operation. Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. Permittee must keep records during periods of startup. Permittee must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

- Permittee must operate all continuous monitoring system (CMS) for the CTG during shutdown. Shutdown means the cessation of operation of a unit for any purpose. Shutdown begins either when none of the steam from the unit is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the turbine. Shutdown ends when there is both no electricity being generated and no fuel being fired in the unit. During shutdown, permittee must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. Permittee must keep records during periods of startup. Permittee must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Operating Limits for EGUs:

As stated in § 63.9991, the permittee must comply with the applicable operating limits:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

If you demonstrate compliance using	You must meet these operating limits
1. Particulate matter continuous parametric monitoring system (PM CPMS)	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

Compliance with these requirements will be better assured with the following condition:

- The permittee shall maintain the 30-operating day rolling average particulate matter continuous parametric monitoring system (PM CPMS) output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s) in compliance with the requirements of Table 5 to Subpart UUUUU of Part 63 (Operating Limits for EGUs). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Performance Testing Requirements:

As stated in § 63.10007, the permittee must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

To conduct a performance test for the following pollutant	Using	You must perform the following activities, as applicable to your input- or output-based emission limit	Using
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A-3 to part 60 of this chapter.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at Appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at Appendix A-8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348-03 [3]with (1) additional quality assurance measures in footnote [4]and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter, ASTM D6784 [3], or Method 29 at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	

	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

Compliance with these requirements will be better assured with the following condition:

- The permittee shall demonstrate compliance with the performance testing requirements of Table 5 to Subpart UUUUU of Part 63 (Performance Testing Requirements). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Establishing PM CPMS Operating Limits:

The permittee proposes to use a particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with the opening limits for the EGU.

Per § 63.10007 and 63.10021, the permittee shall demonstrate compliance with the emission limitations, operating limits, and work practice standards as indicated in Tables 6 and 7:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

If you have an applicable emission limit for	And you choose to establish PM CPMS operating limits, you must	And	Using	According to the following procedures
Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with

				the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

Compliance with these requirements will be better assured with the following condition:

- The permittee shall demonstrate compliance with requirements for establishing PM CPMS operating limits of Table 6 to Subpart UUUUU of Part 63 (Establishing PM CPMS Operating Limits). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Demonstrating Continuous Compliance:

As stated in § 63.10021, the permittee must show continuous compliance with the emission limitations for affected sources according to the following:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards	You demonstrate continuous compliance by
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30-boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-	Operating in accordance with Table 3.

fired EGUs during shutdown	

[77 FR 23405, Apr. 19, 2012]

Compliance with these requirements will be better assured with the following condition:

- The permittee shall demonstrate continuous compliance with the applicable emissions limits, operating limits, or work practice standards in accordance with the Table 7 to Subpart UUUUU of Part 63 (Demonstrating Continuous Compliance). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Reporting Requirements:

As stated in § 63.10031, the permittee must comply with the following requirements for reports:

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit a	The report must contain	You must submit the report
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	Semiannually according to the requirements in § 63.10031(b).
	c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e)	

Compliance with these requirements will be better assured with the following condition:

- In accordance with Table 8 to Subpart UUUUU of Part 63 (Reporting Requirements), permittee must submit a compliance report containing: a) Information required in § 63.10031(c)(1) through (4); and b) If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c). If

you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e). The report shall be submitted semiannually according to the requirements in § 63.10031(b). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

Conclusion:

Compliance with the requirements of this Subpart is expected.

Rule 4101 - Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). None of the equipment proposed will discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). Therefore, compliance with District Rule 4101 requirements is expected.

Rule 4102 - Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Ambient Air Quality Impact and Health Risk Report, which is found in Appendix K, the total facility prioritization score including this project was greater than one. Therefore, a health risk assessment was required to determine the short-term acute and long-term chronic exposure from this project.

As is shown in the Health Risk Analysis Results in section 9.3.6 of the Ambient Air Quality Impact and Health Risk Report in Appendix K, the cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-7616-17-0 through -25-0 and -27-0 through -40-0	0.38 per million	No
S-7616-26-0	2.84 per million	Yes

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. For this project, T-BACT is triggered for PM10 and VOC for unit S-7616-26-0 as indicted in Section 10.3 in Appendix K. According to that section, T-BACT is satisfied with BACT for PM10 and VOC. As is discussed in the BACT discussion in Rule 2201 of this document, BACT is proposed for PM10 and VOC for unit S-7616-26-0.

Therefore, in accordance with the District Risk Management Policy, the project is approved with Toxic Best Available Control Technology (T-BACT) requirements and compliance with the District's Risk Management Policy is expected.

Rule 4201 - Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

S-7616-26-0 (Combustion Turbine Generator)

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate)(7,000 gr/lb)}}{\text{(Exhaust gas flow rate)(60 min/hr)(24 hr/day)}}$$

PM_{10} emission rate: 15.0 lb/hr (assuming 100% of PM is PM10; maximum hourly PM10 rate)
Exhaust gas flow: 1,017,162 to 1,419,360 scfm (as identified in the application. For purposes of this calculation, the lowest value will be used.)

PM Conc. (gr/scf) = [(15.0 lb/hr)(7,000 gr/lb)] ÷ [(1,017,162 ft^3/min)(60 min/hr)]
PM Conc. = 0.0017 gr/scf

S-7616-25-0 (Auxiliary Boiler)

F-Factor for natural gas: 8,578 dscf/MMBtu at 60 °F
PM10 emission factor: 0.0050 lb-PM10/MMBtu
Percentage of PM as PM10 in exhaust: 100%
Exhaust O_2 Concentration: 3%

$$\text{Excess Air Correction to F Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

$$GL = \left(\frac{0.0050\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM} \right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times\ 1.17 \right)$$

$$GL = 0.0035\ grain/dscf < 0.1\ grain/dscf$$

S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

F-Factor for natural gas: 8,578 dscf/MMBtu at 60 °F
PM10 emission factor: 0.0050 lb-PM10/MMBtu
Percentage of PM as PM10 in exhaust: 100%
Exhaust O_2 Concentration: 3%

$$\text{Excess Air Correction to F-Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

$$GL = \left(\frac{0.0050\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM} \right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times\ 1.17 \right)$$

$$GL = 0.0035\ grain/dscf < 0.1\ grain/dscf$$

S-7616-17-0 (Railcar Unloading and Transfer System)
S-7616-18-0 (Truck Unloading and Transfer System)
S-7616-19-0 (Feedstock Storage, Blending, and Reclaim System)
S-7616-20-0 (Feedstock Grinding/Crushing and Drying System)
S-7616-22-0 (Gasification Solids Material Handling System)
S-7616-34-0 (Urea Unit)
S-7616-37-0 (Urea Storage and Loadout System)

The particulate matter emissions from the dust collectors serving the solid material processing equipment will be limited to 0.001 grains/dscf in concentration, which complies with the standard in this rule.

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)

$$0.07\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1\,g-PM}{0.96\,g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.017\ \frac{grain-PM}{dscf}$$

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

$$0.01\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1\,g-PM}{0.96\,g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.002\ \frac{grain-PM}{dscf}$$

Calculated emissions are well below the allowable emissions level. Therefore, compliance with Rule 4201 is expected. The following conditions will be added to the DOC:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 - Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the turbine or the engine. However, it does apply to the cooling towers.

Assuming all cooling tower PM emissions are PM_{10}, Rule 4202 emission limits are calculated as follows:

S-7616-27-0 (Gasification Process Area Cooling Tower)

Weight rate/cooling tower	= (162,582 gal/min)(60 min/hr)(8.34 lb/gal) ÷ 2,000 lb/ton = 40,678 ton/hr
Rule 4202 emission limit	= 17.31 * $P^{0.16}$ (where P greater than 30 tons/hr) = 17.31 * $(40,678)^{0.16}$ = 94.6 lb/hr > Calculated PM rate
Calculated PM rate	= 3.7 lb/hr (87.9 lb/day @ 24 hr/day)

S-7616-28-0 (Air Separation Unit Cooling Tower)

Weight rate/cooling tower	= (44,876 gal/min)(60 min/hr)(8.34 lb/gal) ÷ 2,000 lb/ton = 11,228 ton/hr
Rule 4202 emission limit	= 17.31 * $P^{0.16}$ (where P greater than 30 tons/hr) = 17.31 * $(11,228)^{0.16}$ = 77.0 lb/hr > Calculated PM rate
Calculated PM rate	= 0.22 lb/hr (5.4 lb/day @ 24 hr/day)

S-7616-29-0 (Power Block Cooling Tower)

Weight rate/cooling tower	= (95,500 gal/min)(60 min/hr)(8.34 lb/gal) ÷ 2,000 lb/ton = 23,894 ton/hr
Rule 4202 emission limit	= 17.31 * $P^{0.16}$ (where P greater than 30 tons/hr) = 17.31 * $(23,894)^{0.16}$ = 86.8 lb/hr > Calculated PM rate
Calculated PM rate	= 2.1 lb/hr (51.3 lb/day @ 24 hr/day)

As is shown above, all cooling tower will comply with the Rule 4202 emission limits.

Additionally, the Rule 4202 emissions limits for the solid material handling processing equipment are calculated below:

	Daily Process Rate (ton/day)	Hourly Process Rate (ton/hour)	Rule 4202 Emission Limit (lb-PM10/hr)	Calculated PM10 rate (lb-PM10/hr)
S-7616-17:				
Rail Unloading Vent	6,500	270.83	42.42	0.17
S-7616-18:				
Truck Unloading Vent	2,000	83.3	35.12	0.69
S-7616-19:				
Feedstock Transfer Tower 2	8,740	364.17	44.47	0.01
Feedstock Transfer Tower 1	8,740	364.17	44.47	0.01
Fluxant Unloading Vent	240	10	25.02	0.01
S-7616-20:				
Feedstock Crusher Vent	8,740	364.17	44.47	0.11
Feedstock Bunkers Vent	8,740	364.17	44.47	0.11
S-7616-22:				
Gasification Solids Bucket Elevator	1,900	79.17	34.84	0.03
Gasification Solids Transfer Tower	1,900	79.17	34.84	0.03
Gasification Solids Load-Out System	1,900	79.17	34.84	0.09
S-7616-34:				
Urea Bucket Elevator	3,440	143.33	38.31	0.01
S-7616-37:				
Urea Transfer Tower 1	3,440	143.33	38.31	0.01
Urea Transfer Tower 2	3,440	143.33	38.31	0.01
Urea Transfer Tower 3	3,440	143.33	38.31	0.01
Urea Transfer Tower 4	3,440	143.33	38.31	0.01
Urea Transfer Tower 5	3,440	143.33	38.31	0.01
Urea Loading Vent	3,440	143.33	38.31	0.17

As is shown above, all the solid material handling equipment will comply with the Rule 4202 emission limits. Therefore, compliance with this rule is expected.

Rule 4301 - Fuel Burning Equipment

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as “any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer”.

S-7616-26-0 (Combustion Turbine Generator)

The CTG primarily produces power mechanically, i.e. the products of combustion pass across the power turbine blades which cause the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because CTG primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

The emergency use IC engines produce power mechanically. Therefore, they do not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

S-7616-25-0 (Auxiliary Boiler)
S-7616-33-0 (Ammonia Startup Heater)

This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 m in diameter.

District Rule 4301 Limits			
Pollutant	**NO_2**	**Total PM**	**SO_2**
S-7616-25-0 (lb/day)	30.7	25.6	14.6
S-7616-25-0 (lb/hr)	1.3	1.1	0.6
S-7616-33-0 (lb/day)	14.5	6.6	3.8
S-7616-33-0 (lb/hr)	0.6	0.3	0.2
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, compliance is expected.

Rule 4305 - Boilers, Steam Generators and Process Heaters – Phase 2

S-7616-25-0 (Auxiliary Boiler)
S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

The auxiliary boiler (S-7616-29-0) and the ammonia startup heater (S-7616-33) are natural gas-fired with a maximum heat input of 230 MMBtu/hr and 56 MMBtu/hr, respectively. Pursuant to

Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305. Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 - Boilers, Steam Generators and Process Heaters – Phase 3

S-7616-25-0 (Auxiliary Boiler)
S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

This rule limits NOx and CO emissions from boilers, steam generators, and process heaters rated greater than 5 MMBtu/hr. The subject natural gas-fired auxiliary boiler (S-7616-25) and ammonia synthesis unit startup heater (S-7616-33) will comply with the applicable provisions of this rule. Source testing, monitoring and recordkeeping requirements of Rule 4320 are equal to or more stringent than the requirements of this rule; therefore, compliance is expected

Rule 4320 - Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr

This rule limits NOx, CO, SO2 and PM10 emissions from boilers, steam generators and process heaters rated greater than 5 MMBtu/hr. This rule also provides a compliance option of payment of fees in proportion to the actual amount of NOx emitted over the previous year.

S-7616-25-0 (Auxiliary Boiler)
S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

Section 5 - Requirements

Section 5.1 states that an operator of a unit(s) subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

5.1.1 Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or

5.1.2 Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or

5.1.3 Comply with the applicable Low-use Unit requirements of Section 5.5.

Section 5.0 - NOx and CO Emission Limits

Section 5.2.1 states that on and after the indicated Compliance Deadline, a unit shall not be operated in a manner which exceeds the applicable NOx limit specified in Table 1 of this rule. Units shall not be operated in a manner which exceeds CO emissions of 400 ppmv.

S-7616-25-0 (Auxiliary Boiler)

The auxiliary boiler (S-7616-25-0) in this project is rated at 230 MMBtu/hr heat input, and the permittee plans to equip the boiler with an ultra-low NOx burner and flue gas recirculation to meet a NOx emission limit of 5 ppmv @ 3% O2, and CO emissions will be limited to 50.8 ppmv-CO @ 3% O2. Based on that heat input rating, the applicable emission limit category Section 5.2, Table 1, Category B, from District Rule 4320 is as follows:

Rule 4320 NOx Emission Limits			
Category	**NOx Limit**	**Application**	**Compliance Deadline**
Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule: 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Enhanced Schedule: 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014

Therefore, S-7616-25 will be in compliance with the applicable NOx and CO emission limits.

The following condition will be added to S-7616-25:

- Emissions from this unit, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 5 ppmvd @ 3% O_2 or 0.006 lb/MMBtu, SOx (as SO_2): 0.00285 lb/MMBtu, PM_{10}: 0.005 lb/MMBtu, CO: 50.8 ppmvd @ 3% O_2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

S-7616-33-0 (Ammonia Synthesis Unit Startup Heater)

A 56 MMBtu/hr natural gas-fired startup heater is provided in the ammonia synthesis unit to raise the catalyst bed temperatures during initial plant commissioning, or during startup after a plant maintenance outage. The startup heater transfers heat from combustion gases to the ammonia stream, a process stream, and as such meets the definition of a process heater as defined in Section 3.19 of the rule.

For the proposed ammonia startup heater, the permittee proposes to pay an annual emissions fee to the District as allowed by Section 5.1.2. The fee shall be calculated annually as specified in Section 5.3.

The following condition will be added to S-7616-33:

- Pursuant to Rule 4320, the operator shall pay an annual emission fee to the District for NOx emissions from this unit for the previous calendar year. Payments are due by July 1 of

each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

Section 5.4 - Particulate Matter Control Requirements

The applicable particulate matter control requirement of Section 5.4 will be satisfied by both units (S-7616-25 and -33) by complying with Section 5.4.1.1, by operating the units exclusively on PUC-quality natural gas.

- The unit shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 4320]

Section 5.6 - Startup and Shutdown Provisions

Section 5.6 states that on and after the full compliance deadline specified in Section 5.0, the applicable emission limits of Sections 5.2 Table 1 and 5.5.2 shall not apply during startup or shutdown provided an operator complies with the requirements specified in Sections 5.6.1 through 5.6.5.

Section 5.6 specifies startup and shutdown provisions. Section 5.6.1 states that the duration of each startup or each shutdown shall not exceed two hours, except as provided in Section 5.6.3, whereby the applicant applies and received approval for more than two hours for each startup or each shutdown.

The applicant has not proposed startup and shutdown duration limits greater than those specified in section 5.6.1. Emissions during startup and shutdown will not be subject to the emission limits in Sections 5.2 and 5.2.2. The following condition will be added to S-7616-29 and -33:

- Duration of startup and shutdown of heater shall not exceed 2 hours each per occurrence. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. The operator shall maintain records of the duration of startup and shutdown. [District Rules 4305, 4306, and 4320]

Section 5.7 - Monitoring Provisions

Section 5.7.1 requires that units subject to District Rule 4320, Section 5.2 shall either install and maintain an operational APCO approved Continuous Emission Monitoring System (CEMS) for NO_X, CO and O_2, or implement an APCO-approved alternate monitoring.

The permittee proposes to implement Alternate Monitoring Scheme A (pursuant to District Policy SSP-1105), which requires that monitoring of NO_X, CO, and O_2 exhaust concentrations shall be conducted at least once per month (in which a source test is not performed) using a portable analyzer. The following conditions will be incorporated into S-7616-25 and -33 to ensure compliance with the requirements of the proposed alternate monitoring plan:

- The permittee shall monitor and record the stack concentration of NO_X, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Measurement shall be made with the FGR system in the mode of operation (closed or open) in which it was used in the preceding 30 days. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

- If either the NO_X or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]

- All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

- The permittee shall maintain records of: (1) the date and time of NO_X, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320]

Section 5.7.6 requires that operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District. Provided the units are fired on PUC-quality natural gas as required, the units are expected to comply with this section.

Section 5.8 - Compliance Determination

Section 5.8.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu), emission limits or the concentration (ppmv) emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the S-7616-25 and -33 as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320]

Section 5.8.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following condition will be listed on S-7616-25 and -33 as follows:

- All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. Unless otherwise specified in the DOC, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. For the purposes of permittee-performed alternate monitoring, emissions measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

Section 5.8.4 requires that for emissions monitoring pursuant to Sections 5.7.1 and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following condition will be added to S-7616-25 and -33:

- All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following condition will be listed on S-7616-25 and -33:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

Section 6.1 - Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

The following condition will be added to S-7616-25 and -33:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

Section 6.2 - Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following conditions will be listed on S-7616-25 and -33 as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB

Method 100, stack gas oxygen - EPA Method 3 or 3Aor ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rules 4305, 4306 and 4320]

Section 6.3 - Compliance Testing

Section 6.3.1 requires that each unit subject to the NOx and CO emission limits shall be source tested at least once every 12 months, except if two consecutive annual source tests demonstrate compliance, source testing may be performed every 36 months. If such a source test demonstrates non-compliance, source testing shall revert to every 12 months. The following conditions will be included in S-7616-25 and -33:

- This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306 and 4320]

- Source testing to measure NOx, and CO emissions shall be conducted within 60 days of initial operation and whenever flue gas recirculation rate is changed. [District Rules 2201, 4305, 4306 and 4320]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4 - Emission Control Plan (ECP)

Section 6.4 requires the operator of any unit to submit to APCO for approval an Emissions Control Plan no later than January 1, 2010. The applicant is not yet an operator of the units, so an ECP is not due yet.

Section 7.0 - Compliance Schedule

Section 7.0 identifies the dates by which the operator shall submit an application for an ATC (and in this case a DOC) and the date by which the owner shall demonstrate compliance with this rule.

The units will be in compliance with the emissions limits listed in Table 1, Section 5.2 of this rule, and periodic monitoring and source testing as required by District Rule 4320. Therefore, requirements of the compliance schedule, as listed in Section 7.0 of District Rule 4320, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into S-7616-25 and -33 in order to ensure compliance with each section of this rule, see attached draft DOC. Therefore, compliance with District Rule 4320 requirements is expected.

Rule 4311 - Flares

S-7616-30-0 (Gasification Flare)
S-7616-31-0 (Sulfur Recovery Unit Flare)
S-7616-32-0 (Rectisol Flare)

The purpose of this rule is to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), and sulfur oxides (SOx) from the operation of flares.

Section 5.0 - Requirements

Section 5.1 states that flares that are permitted to operate only during an emergency are not subject to the requirements of Sections 5.6 and 5.7. Since all three of the proposed flares for the project will be allowed some non-emergency operation (such as for startup and shutdown events), all three flare are subject to the requirements of Sections 5.6 and 5.7.

Section 5.2 requires a flame to be present at all times when combustible gases are vented through the flare. The following condition on S-7616-30, -31, and -32 will ensure compliance with Section 5.2:

- A flame shall be present at all times when combustible gases are vented through this flare. [District Rules 2201 and 4311, 5.2 and 40 CFR 60.18(c)(2)]

Section 5.3 requires the flare outlet to be equipped with an automatic ignition system or to operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. The following condition on S-7616-30, -31, and -32 will ensure compliance with Section 5.3:

- The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]

Except for flares equipped with a flow-sensing ignition system, Section 5.4 requires the flare be equipped with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present to be installed and operated. The flares in this project each have a continuous pilot; therefore, the following condition will be included on S-7616-30, -31, and -32 to ensure compliance with Section 5.4:

- Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

Section 5.5 requires flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. Each flare is equipped with a continuous pilot; therefore, this section is not applicable.

Section 5.6 requires open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18.

The flare gas pressure of all three flares (S-7616-30, -31 and -32) will be less than 5 psig. Therefore, the requirements of Section 5.6 and 40 CFR 60.18 will be included on S-7616-30, -31 and -32. The following condition will be included on S-7616-30, -31 and -32:

- Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

Additionally, conditions addressing the specific requirements of 40 CFR 60.18 (General Control Device and Work Practice Requirements), a separate section below discussed below, will be included on S-7616-30, -31 and -32 in order to comply with Section 5.6 of this rule.

Section 5.7 applies to ground level enclosed flares. The proposed flares in this project are not ground level enclosed flares; therefore, this section is not applicable.

Section 5.8 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour to submit a flare minimization plan (FMP) to the APCO for approval. All three proposed flares have a capacity greater than 5.0 MMBtu/hr. Therefore, the following condition will be included on S-7616-30, -31, and -32:

- No less than 90 days prior to installation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rule 4311, 6.5]

Section 5.9 does not apply as it applies to petroleum refinery flares.

Section 5.10 states the operator of a flare subject to flare minimization requirements pursuant to Section 5.8 shall monitor the vent gas flow to the flare with a flow measuring device or other parameters as specified in the DOC. The operator shall maintain records pursuant to Section 6.1.7.

- Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rule 2201]

Section 5.11 states that the operator of a petroleum refinery or a flare with a flaring capacity equal to or greater than 50 MMBtu/hr shall monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10. Flares S-7616-30, 31, and -32 have a flaring capacity greater than 50 MMBtu/hr, so the monitoring requirements of those sections apply to S-7616-30, -31, and -32 as discussed in the respective sections below.

Section 6.0 - Administrative Requirements
Section 6.1 - Recordkeeping

Section 6.1.1 requires the operator of flares that are subject to the requirements of 40 CFR 60.18 to make available to the APCO upon request the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5).

Flares S-7616-30, -31 and -32 are subject to the requirements of 40 CFR 60.18 per Section 5.6; therefore, Section 6.1.1 is applicable to these flares. Therefore the following conditions will be included on S-7616-30, -31 and -32:

- Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

- Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

- The permittee shall keep accurate daily records of the amount of gas combusted in the flare, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201 and 4311]

Section 6.1.2 applies to ground level enclosed flares. None of the proposed flare will be ground level enclosed flare; therefore, this section is not applicable.

Section 6.1.3 requires for flares used during an emergency that records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation be maintained. The following conditions will be added to S-7616-30, -31, and -32:

- Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Section 6.1.4 does not apply as the operator is not claiming an exemption pursuant to Section 4.3.

Section 6.1.5 requires the permittee to retain on site a copy of the approved flare minimization plan. The following condition will be added to S-7616-30, -31, and -32:

- Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Section 6.1.6 requires the permittee to retain a copy of annual reports submitted to the APCO pursuant to Section 6.2. The following condition will be added to S-7616-30, -31, and -32:

- Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

Section 6.1.7 requires the permittee to retain monitoring data, where applicable, collected pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10. Section 5.10 (flare minimization vent gas flow rate) applies. Therefore monitoring data for that section will be required. Monitoring for the other section applies only to petroleum refinery flares. The following condition will be added to S-7616-30, -31, and -32:

- Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, Section 6.1]

Section 6.2 - Flare Reporting

Section 6.2.1 states that the operator of a flare subject to flare minimization plans pursuant to Section 5.8 of this rule shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. The following condition will be added to S-7616-30, -31, and -32:

- The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, Section 6.2]

Section 6.2.2 states that the operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report (as described in that section) shall be submitted within 30 days following the end of the twelve month period of the previous year. The following condition will be added to S-7616-30, -31, and -32:

- The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, Section 6.2]

Section 6.2.3 states that the operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include components specified in Section 6.2.3.1 through 6.2.3.8. Section 5.10 (flare minimization vent gas flow rate) applies, therefore monitoring data for that section will be required. Monitoring for the other section applies only to petroleum refinery flares. The following condition will be added to S-7616-30, -31, and -32:

- The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, Section 6.2]

Section 6.3 – Test Methods

Section 6.3 lists the approved test methods to demonstrate compliance with this rule. Alternate equivalent test methods may be used provided the test methods have been approved by the APCO and EPA. Those methods shall be listed on S-7616-30, -31, and -32 as appropriate.

Section 6.4 - Compliance Determination

Section 6.4.1 states that upon request, the operator of flares that are subject to Section 5.6 shall make available, to the APCO, the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). Flares S-7616-30, -31 and -32 are subject to Section 5.6. Therefore, the following condition will be added to S-7616-30, -31 and -32:

- Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

Section 6.4.2 applies to ground-level enclosed flares. None of the flare in this project will be ground-level flares, so this section does not apply.

Section 6.5 - Flare Minimization Plan

Section 6.5.1 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour to submit a flare minimization plan (FMP) to the APCO for approval. The following condition will be added to S-7616-30, -31, and -32:

- No less than 90 days prior to operation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rule 4311, 6.5]

Sections 6.6, 6.7, 6.8, and 6.9 are applicable to flares with an hourly heat input exceeding 50 MMBtu/hr, and therefore these sections potentially apply to flares S-7616-30 (4,000 MMBtu/hr), and S-7616-31 (2,100 MMBtu/hr) and S-7616-32 (5,500 MMBtu/hr).

Section 6.6 - Vent Gas Composition Monitoring

Section 6.6 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour to monitor vent gas composition of that flare using one of the five methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. Therefore, the following conditions will be added to flares S-7616-30, -31, -32, which have a flare capacity greater than 50 MMBtu/hr:

- Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, Section 6.6]

Section 6.7 – Pilot and Purge Gas Monitoring

Section 6.7 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour to monitor the volumetric flows of purge and pilot gases with flow measuring devices or other parameters as specified on the DOC so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored. Therefore, the following condition will be added to S-7616-30, -31 and -32, which have a flare capacity greater than 50 MMBtu/hr:

- The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, Section 6.7]

Section 6.8 – Water Seal Monitoring

Section 6.8 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour with a water seal shall monitor and record the water level and pressure of the water seal that services each flare daily or as specified in the DOC. Therefore, the following condition will be added to S-7616-30, -31, and -32, which have a flare capacity greater than 50 MMBtu/hr:

- If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, Section 6.8]

Section 6.9 - General Monitoring

Section 6.9 requires the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour shall comply with the following, as applicable:

Section 6.9.1 states that periods of flare monitoring systems in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating.

Section 6.9.2 states that during periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices.

Section 6.9.3 states that the permittee shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure.

Section 6.9.4 states that all in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

Therefore the following conditions will be included on S-7616-30, -31, and -32:

- Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, Section 6.9]

- During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, Section 6.9]

- Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a

manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, Section 6.9]

- All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, Section 6.9]

Section 6.10 – Video Monitoring

This section is not applicable as it addresses petroleum refinery flares.

Section 7.0 Compliance Schedule

Operators of flares, that are exempt under Section 4.0 and that lose exemption status, shall not operate flares until in full compliance with all applicable requirements of this rule effective on the date the exemption status is lost. The flares are not exempt under Section 4.0. Therefore, this section is not applicable.

Compliance with the rule is expected.

40 CFR 60.18 - General Control Device and Work Practice Requirements

District Rule 4311 (Flares) Section 5.6 requires open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18.

The flare gas pressure of all three flares in this project (S-7616-30, -31 and -32) will be less than 5 psig. Therefore, the requirements of Section 5.6 and 40 CFR 60.18 will be included on S-7616-30, -31 and -32.

According to paragraph 60.18(b), paragraphs (c) through (f) apply to flares.

(c)(1) This subpart requires no visible emissions. Flares shall be designed for and operated with no visible emissions as determined by EPA Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. The following conditions will be included S-7616-30, -31 and -32:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

- A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes

company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rules 4311]

(c)(2) This subpart requires a flame to be present at all times. The flare shall be operated with a flame present at all times. Presence of a flame shall be monitored using a thermocouple or equivalent device to detect the presence of a flame. The flare is equipped with a pilot flame monitoring device.

The following two conditions to be included on S-7616-30, -31 and -32 require a continuous pilot flame and smokeless combustion:

- A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311, 5.2 and 40 CFR 60.18(c)(2)]

- Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

(c)(3) This subpart gives the operator the option of complying with either (c)(3)(i), or (c)(3)(ii) and (c)(4).

The following condition will be included on S-7616-30, -31 and -32:

- No less than 90 days prior to operation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i) or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

(c)(3)(i) This subpart states that flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity, Vmax, as determined in that section.

The following conditions will be added to S-7616-30, -31 and -32:

- If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0% by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18 (c)(3)(i)(a)]

(c)(3)(ii) This subpart lists the minimum heating value of gas being combusted in a non-assisted flare as 200 Btu/scf.

The following conditions will be added to S-7616-30, -31 and -32:

- If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

(c)(4)(i) This subpart lists a maximum velocity for nonassisted flares as 60 ft/sec, except as provided by (c)(4)(ii) and (c)(4)(iii).

(c)(4)(ii) This subpart lists a maximum exit velocity of 400 ft/sec when the gas being combusted has a heating value of 1,000 Btu/scf. Based on the heat input rating and diameter of the flare, it will not operate with an exit velocity of 400 ft/sec or greater.

Compliance with this subpart is expected, and the following conditions will be added to S-7616-30, -31 and -32:

- If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18 (c)(4)]

- If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18 (c)(4)]

(c)(4)(iii) This subpart sets a maximum exit velocity, based on the heating value of the gas combusted and the equation listed in (f)(5).

The following conditions will be added to S-7616-30, -31 and -32:

- If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18 (c)(4)(iii)]

(d) This subpart requires the owner or operator to monitor the flare to ensure it is operated and maintained in conformance with its design. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

Monitoring requirements of District Rule 4311 mentioned earlier, will ensure compliance with this section.

(e) This subpart requires that the flare be operational when emissions may be vented to the flare. The presence of a continuous pilot flame will ensure that the flare is operational.

The following conditions are included on S-7616-30, -31 and -32:

- A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311, 5.2 and 40 CFR 60.18(c)(2)]

- Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

(f) This subpart lists the methods and equations to be used to demonstrate compliance with the paragraphs of this subpart. Compliance with the above-listed conditions ensures compliance with this paragraph.

The following conditions are included on S-7616-30, -31 and -32:

- The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18 (f)(3)]

- The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18(f)(1)]

- The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40CFR 60.18(f)(2)]

- Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. [District Rule 4311, 5.4 and 40 CFR 60.18(f)(2)]

- The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18 (f)(4)]

Rule 4351 - Boilers, Steam Generators and Process Heaters – Phase 1

This rule does not apply to any unit located west of Interstate Highway 5 located in Fresno, Kern, or Kings County. Since the operation is located west of Interstate Highway 5 in Kern County, this rule does not apply.

Rule 4455 - Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

This rule applies to components containing or contacting VOC at petroleum refineries, gas liquids processing facilities, and chemical plants. Since the facility is none of the affected facilities, the rule does not apply. However, the Inspection and Maintenance requirements of the rule (Sections 5.2 and 5.3) do apply as BACT requirements, so the conditions specifying those requirements will list Rule 2201 as the rule requiring them.

Rule 4701 - Internal Combustion Engines – Phase 1

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 - Internal Combustion Engines – Phase 2

This rule applies to any internal combustion engine rated at 25 brake horsepower or greater. The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC), and sulfur oxides (SOx) from internal combustion engines.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the emergency IC engines involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO.

The following table demonstrates how the proposed engines will comply with the requirements

of District Rule 4702.

District Rule 4702 Requirements Emergency Standby IC Engines	Proposed Method of Compliance with District Rule 4702 Requirements
Operation of emergency standby engines is limited to 100 hours or less per calendar year for non-emergency purposes, verified through the use of a non-resettable elapsed operating time meter.	The Air Toxic Control Measure for Stationary Compression Ignition Engines (Stationary ATCM) limits this engine maintenance and testing to 50 hours/year. Thus, compliance is expected.
Emergency standby engines cannot be used to reduce the demand for electrical power when normal electrical power line service has not failed, or to produce power for the electrical distribution system, or in conjunction with a voluntary utility demand reduction program or interruptible power contract.	The following conditions will be included on the DOC: {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702] {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]
The owner/operator must operate and maintain the engine(s) and any installed control devices according to the manufacturers written instructions.	A DOC condition enforcing this requirement was shown earlier in the evaluation.
The owner/operator must monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.	The following condition will be included on DOC: {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

Records of the total hours of operation of the emergency standby engine, type of fuel used, purpose for operating the engine, all hours of non-emergency and emergency operation, and support documentation must be maintained. All records shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request.	The following conditions will be included on the DOC: {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115] The permittee shall maintain monthly records of the type of fuel purchased. [District Rule 4702 and 17 CCR 93115] {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

Therefore, the following conditions will be listed on the emergency engine DOC to ensure compliance:

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

- {3488} This engine shall be operated only for maintenance, testing, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

Rule 4703 - Stationary Gas Turbines

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts, and it defines a gas turbine as "an internal combustion engine consisting of a compressor, a combustor, and a power turbine that is gas and/or liquid fueled, with or without power augmentation." This rule defines "gas fuel" in Section 3.10 as "any of the following fuels or fuels containing any of the following fuels: natural gas, LPG, propane, digester gas, and landfill gas."

S-7616-26-0 (Combustion Turbine Generator)

Hydrogen-rich fuel is not considered gas fuel per the definition of gas fuel as defined in the rule, so this rule will not apply to the CTG when firing solely on hydrogen-rich fuel. However, when firing on natural gas the requirements of this rule will apply.

Section 5.1 – NOx Emission Requirements:

When operating on natural gas, the proposed gas turbine with a generating capacity of up to 431 nominal gross MW. Section 5.1.2 (Table 5-2: Tier 2 NOx Compliance Limits) of this rule limits the NO_X emissions from combined cycle gas turbines greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option) for gas fuel as shown in the table below. The applicant's proposal of 4.0 ppm-NOx when firing on natural gas satisfies the standard compliance option.

Turbine Classification Rating	Compliance Option (see Section 7.2)	NOx Compliance Limit, ppmvd at 15% O2	
		Gas Fuel	Liquid Fuel
d) Greater than 10 MW, Combined cycle.	Standard	5	25
	Enhanced	3	5

As discussed above, the proposed turbine will be limited to NOx emission less than those specified in Section 5.1, therefore compliance with this section is expected.

Section 5.2 – CO Emission Requirements:

Per Section 5.2 (Table 5-4: CO Compliance Limits), the CO emissions concentration from the gas turbine must be less than 200 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three-hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three-hour period.

The CO emission concentration will be limited to 5.0 ppmvd-CO @ 15% O2 when firing on fuel containing natural gas. Therefore, the proposed turbine will be in compliance with the CO emission requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on natural gas shall not exceed any of the following: NOx (as NO2) - 34.1 lb/hr and 4.0 ppmvd-NOx @ 15% O2; VOC (as methane) - 5.9 lb/hr and 2.0

ppmvd-VOC @ 15% O2; CO - 26.0 lb/hr and 5.0 ppmvd-CO @ 15% O2; PM10 - 15.0 lb/hr; or SOx (as SO2) - 4.7 lb/hr. All pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 5.3 – Transitional Operation Periods Requirements:

This section states that the emission limit requirements of Sections 5.1 and 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

As allowed by Section 5.3.3, the applicant is proposing more than the duration of each startup and shutdown allowed by the rule, and as such has provided a written request and supporting information to the District. The District shall provide EPA and ARB with a copy of the evaluation of this request for EPA and ARB approval. Per Section 5.3.3.2, at a minimum, a justification for the increased duration shall include the following:

- A clear identification of the control technologies or strategies to be utilized ; and
- A description of what physical conditions prevail during the period that prevent the controls from being effective; and
- A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and
- A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and
- A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and
- The basis for the requested additional duration.

MHI, the turbine manufacturer, has estimated that each startup or shutdown event will be more than the two hours per event. The applicant proposes to limit the duration of each startup and shutdown event according to the manufacturer's recommendations as indicated in the tables below. During this period, the permittee will operate the catalytic emission controls during the startup/shutdown periods within the constraint of the minimum catalyst temperature for ammonia injection to avoid SCR fouling. Each necessary step, its duration, and emission rates are also indicated in the tables below:

CTG /HRSG Startup	
Step	**Duration (hr)**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2
3.CTG fuel change-over, 40 percent load on syngas, startup PSA/ ammonia/urea units	2
Feedstock Dryer Startup	
Step	**Duration (hr)**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2
3. CTG fuel change-over, 40 percent load on syngas	2
CTG/HRSG Shutdown	
Step	**Duration (hr)**
1. PSA, ammonia, and urea unit shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4
2.CTG fuel change-over, 40 percent load on natural gas, gasifier depressurization	3
3. Minimum plant load, 20 percent load on natural gas	2
Feedstock Dryer Shutdown	
Step	**Duration (hr)**
1. PSA, ammonia, and urea unit shutdown; gasifier to 60 percent; CTG to 40 percent load on syngas	4

The oxidation catalyst will start functioning automatically as soon as it reaches its operating temperature range. The only action to be taken in order to begin catalytic operation is to start the ammonia injection into the SCR. The ammonia injection must wait until the SCR reactor exceeds the maximum temperature for ammonium sulfate precipitation to avoid fouling the catalyst.

Therefore the following conditions that limit the duration of the startup and shutdown periods will be added to S-7616-26:

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to normal operations emission compliance. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status when emissions exceed normal operating limits, by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup shall not exceed 4.5 hours, and the duration of each shutdown shall not exceed 9.0 hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. The applicant proposes to operate a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content for both the CTG/HRSG stream and the feedstock dryer exhaust.

As is explained earlier in this evaluation, during normal operation of the CTG/HRSG and some phases of the startup and shutdown activities, a portion of the treated HRSG flue gas will be diverted to the feedstock drying system, filtered through a baghouse, then exhausted from the coal-dryer stack. As a result, the emissions from the HRSG and feedstock dryer stacks are interconnected. Since it is not feasible to monitor the CTG/HRSG exhaust stream prior to being diverted to the feedstock dryer, the permittee will be required to operate CEMS that monitors the NOx and oxygen content for both the CTG/HRSG stream and the feedstock dryer exhaust.

The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

- One CEMS shall continuously measure and record the parameters in the condition above for both the CTG/HRSG exhaust and the feedstock dryer exhaust. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. The proposed turbine will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbine will be a new installation. Therefore, it was not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. The permittee will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbine will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. The permittee will be required, by DOC condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbine will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this DOC when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. The permittee will be required to maintain records of each item listed above. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

- The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this

rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, the permittee will be required, by condition, to maintain records of the date, time and duration of each startup and shutdown. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing and Test Methods:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The proposed turbine is subject to the provisions of Section 5.0 of this rule. Therefore, it will be required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. The proposed turbine will be allowed to operate more than 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. The permittee is not proposing to operate the turbine with auxiliary burners. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following conditions will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

Conclusion:

Conditions will be incorporated into the DOC in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 - Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2% by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

S-7616-26-0 (Combustion Turbine Generator)

The sulfur content of the natural gas fuel will be no greater than 0.75 gr/100 dscf (12 ppm-SOx or 0.0021 lb-SOx/MMBtu) and that of the hydrogen-rich fuel will be no greater than 5 ppm-SOx. Therefore, the following demonstration will be based on the sulfur content of the natural gas.

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) / P

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.0021\,\boldsymbol{lb-SOx}}{\boldsymbol{MMBtu}}\times\frac{\boldsymbol{MMBtu}}{8{,}578\,\boldsymbol{dscf}}\times\frac{1\,\boldsymbol{lb\cdot mol}}{64\,\boldsymbol{lb}}\times\frac{10.73\,\boldsymbol{psi\cdot ft^3}}{\boldsymbol{lb\cdot mol\cdot{}^\circ R}}\times\frac{520^\circ\boldsymbol{R}}{14.7\,\boldsymbol{psi}}\times\frac{1{,}000{,}000\cdot\boldsymbol{parts}}{\boldsymbol{million}}=1.5\,\frac{\boldsymbol{parts}}{\boldsymbol{million}}$$

$\boldsymbol{SulfurConcentration}=1.5\,\frac{\boldsymbol{parts}}{\boldsymbol{million}}$ < 2,000 ppmv (or 0.2%)

Since 1.5 ppmv ≤ 2000 ppmv, the turbine is expected to comply with Rule 4801.

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

Volume SO_2 = (n x R x T) / P

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\,\boldsymbol{lb-S}}{\boldsymbol{lb-fuel}}\times\frac{7.1\,\text{lb}}{\text{gal}}\times\frac{64\,\text{lb}-\text{SO}_2}{32\,\text{lb}-\text{S}}\times\frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}}\times\frac{1\,\text{gal}}{0.137\,\text{MMBtu}}\times\frac{\text{lb}-\text{mol}}{64\,\text{lb}-\text{SO}_2}\times\frac{10.73\,\text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}}\times\frac{520^\circ\text{R}}{14.7\,\text{psi}}\times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition will be added to S-7616-38 through '-40 to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

S-7616-25-0 (Auxiliary Boiler)
S-7616-33-0 (Ammonia Startup Heater)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) / P

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.00285\,\boldsymbol{lb-SOx}}{\boldsymbol{MMBtu}}\times\frac{\boldsymbol{MMBtu}}{8{,}578\,\boldsymbol{dscf}}\times\frac{1\,\boldsymbol{lb\cdot mol}}{64\,\boldsymbol{lb}}\times\frac{10.73\,\boldsymbol{psi\cdot ft^3}}{\boldsymbol{lb\cdot mol\cdot{}^\circ R}}\times\frac{520^\circ\boldsymbol{R}}{14.7\,\boldsymbol{psi}}\times\frac{1{,}000{,}000\cdot\boldsymbol{parts}}{\boldsymbol{million}}=2.0\frac{\boldsymbol{parts}}{\boldsymbol{million}}$$

$\boldsymbol{SulfurConcentration}=2.0\frac{\boldsymbol{parts}}{\boldsymbol{million}}$ < 2,000 ppmv (or 0.2%)

Since 2.0 ppmv ≤ 2000 ppmv, the auxiliary boiler and the ammonia startup heater are expected to comply with Rule 4801. Therefore, compliance with District Rule 4801 requirements is expected.

Rule 7012 - Hexavalent Chromium – Cooling Towers

Since the proposed cooling towers will not and have never had hexavalent chromium containing compounds added, the cooling towers will be exempt from the provision of this rule except for the Sections 5.2.1, 6.1, and 7.1.

Section 5.2.1 requires that no hexavalent chromium compounds be added after 9/16/91 (intended to apply to cooling towers that previously used hexavalent chromium). A DOC condition will be added to satisfy this requirement.

Section 6.1 requires that the owner/operator of a new cooling tower submit a compliance plan at least 90 days before it is operated containing business information, location of cooling tower, type and materials of construction, and a statement regarding the use or non-use of hexavalent chromium. A DOC condition will be added to satisfy this requirement.

The following conditions will be added to S-7616-27 through '-29-0:

- Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

- No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Section 7.1 requires that the permittee pay filing fees associated with the cooling tower as specified in Rule 3010 (Permit Fee). The applicant has already paid such fees with the submittal of this project's applications. Therefore, compliance is expected.

Rule 8011 - General Requirements

The definitions, exemptions, requirements, administrative requirements, recordkeeping requirements, and test methods set forth in this rule are applicable to all rules under Regulation VIII (Fugitive PM10 Prohibitions) of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.

Rule 8021 - Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities

The purpose of this rule is to limit fugitive dust emissions from construction, demolition, excavation, and other earthmoving activities. It requires the use of control measures to maintain visible dust emissions (VDE) under the 20% opacity requirement.

The applicant will commit to the use of dust control measures (e.g., water, approved chemical stabilizers, etc.) during construction to maintain opacity to a level below 20% per Rule 8021 requirements. Compliance with the requirements of this rule is anticipated.

Proposed Rule 8021 Condition:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

Rule 8031 - Bulk Materials

Pursuant to Section 2.0, this rule is applicable to the outdoor handling, storage, and transport of any bulk material. The following condition will be added to the DOC to satisfy the requirements of the rule.

Proposed Rule 8031 Condition:

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application

of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

Rule 8051 - Open Areas

Pursuant to Section 2.0, this rule is applicable to any open area having 3.0 acres or more of disturbed surface area that has remained undeveloped, unoccupied, unused or vacant for more than seven days. The following condition will be added to the DOC to satisfy the requirements of the rule.

Proposed Rule 8051 Condition:

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

Rule 8061 - Paved and Unpaved Roads

Pursuant to Section 2.0, this rule applies to any new or existing public or private paved or unpaved road, road construction project, or road modification project. The following condition will be added to the DOC to satisfy the requirements of the rule.

Proposed Rule 8061 Condition:

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

Rule 8071 - Unpaved Vehicle/Equipment Traffic Areas

Pursuant to Section 2.0, this rule applies to any unpaved vehicle/equipment traffic area of 1.0 acre or larger. The following condition will be added to the DOC to satisfy the requirements of the rule.

Proposed Rule 8071 Condition:

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the

requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

Rule 9110 - General Conformity and 40 CFR Part 93

District Rule 9110 and 40 CFR Part 93 Subpart B, "Determining Conformity of Federal Actions to State or Federal Implementation Plans," requires that Federal agencies make determinations that Federal Actions conform to approved State Implementation Plans (SIPs), as outlined in the subpart, before Federal Actions are taken, i.e. that the emission increases due to Federal Actions "conform" with approved SIPs and would not delay or impede the region's attainment

This project is a Federal action as the United States Department of Energy is providing substantial funding to the project and is playing a direct role in the design of the project.

Per 40 CFR 93.153, a conformity determination is not required for portions of projects subject to New Source Review requirements. This project is subject to the District's New Source Review Rule (Rule 2201), and direct emissions of NOx and VOC (as well as CO, PM10, and SOx) from the facility and are being mitigated through Rule 2201 requirements that include Best Available Control Technology and offsetting of emissions through the withdrawal of emission reduction credits. As such, direct emissions of NOx and VOC are being mitigated.

Per 40 CFR 93.153 and the San Joaquin Valley's attainment status (extreme nonattainment for ozone, nonattainment for PM2.5, and maintenance for PM10 and carbon monoxide), the following conformity thresholds apply:

- 10 tons per year (tpy) NOx
- 10 tpy VOC
- 100 tpy SO2
- 100 tpy carbon monoxide
- 100 tpy directly-emitted PM2.5
- 100 tpy directly-emitted PM10

Indirect emissions are expected to exceed the conformity threshold for NOx due to construction and operation emissions, and the conformity threshold for VOC due to construction emissions.

The indirect NOx and VOC emissions due to the project that exceed the conformity threshold will be mitigated through a mitigation agreement between HECA and the District, subject to

Governing Board approval. This agreement will result in the full mitigation of indirect NOx and VOC emissions during construction and NOx emissions during operations from this project.

Through this mitigation agreement, HECA would provide the District with adequate funds to be used in the District's emission reduction incentive programs to fully mitigate the project's NOx and VOC emissions during construction, and NOx emissions during operations.

In addition to addressing general conformity requirements, the mitigation agreement would also be used to help address CEQA requirements, as discussed below.

With this agreement, the District believes that the emissions from the project will be fully mitigated (see Appendix G for the calculation methodology that the parties have agreed will be the basis of the agreement). As such, the District believes that conformity with the SIP has been demonstrated.

The Agreements, which address the necessary mitigation under both General Conformity and CEQA, were approved by the District's Governing Board. A copy of the agreements is found in Appendix L.

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.

- Identify the ways that environmental damage can be avoided or significantly reduced.

- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.

- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The California Energy Commission (CEC) has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(k)), it is functionally equivalent to CEQA.

The District holds no discretionary approval powers over this project; however the District prepares a Determination of Compliance (DOC), this document. The DOC confers the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this DOC (20 CCR § 1744.5 and Rule 2201 § 5.8.8). A Permit to Operate is required to be issued if the project receives a certificate from the CEC and the project is constructed in accordance with the conditions set forth in the DOC (Rule 2201 § 5.8.9).

The District makes the following findings regarding this project: the District holds no discretionary approval powers over this project and the District's actions are ministerial (CEQA Guidelines § 15369).

However, by implementing District Rule 2201, *New and Modified Stationary Source Review*, project direct stationary source emissions will be reduced and mitigated through the withdrawal of emission reduction credits to below the District's thresholds of significance.

In addition, to mitigate indirect emissions associated with construction and operations of the project, HECA will be entering into a contractual Mitigation Agreement (Agreement) with the District. This Agreement will result in mitigation of indirect project emissions for purposes of satisfying General Conformity and CEQA requirements.

Under the Agreement, HECA will provide the necessary funds used by the District to achieve the required emission reductions, thus mitigating project indirect air quality emissions.

For indirect construction emission impacts, emissions from any criteria pollutant exceeding the General Conformity Threshold or the District CEQA Significance Threshold in any given year will be fully mitigated for that pollutant for the entire project construction period. For indirect operational emission impacts, emission from any criteria pollutant exceeding the General Conformity Threshold or the District CEQA Significance Threshold will be fully mitigated for that pollutant (see Appendix G for the calculation methodology that the parties have agreed will be the basis of the agreement).

The Agreements, which address the necessary mitigation under both General Conformity and CEQA, were approved by the District's Governing Board. A copy of the agreements is found in Appendix L.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

S-7616-40-0 (Emergency Engine Powering Firewater Pump)

Title 13 CCR, Section 2423 lists diesel engine emission standards. The proposed 556 bhp Cummins QSB4.5 Series emergency diesel IC engine (or approved equivalent) will be required to meet the latest Tier emission standard in effect at the time of acquisition as specified in the Off-Road Compression Ignition Engine Standards for off-road engines on the applicable dates specified. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the proposed engine.

Requirements of Title 13 CCR, Section 2423						
Source	Maximum Rated Power	Model Year	NO_X	VOC	CO	PM
Title 13 CCR, §2423	301.7 – 603.4 bhp (225 - 450 kW)	2011-2013 (Interim Tier 4)	1.5 g/bhp-hr	0.14 g/bhp-hr	2.6 g/bhp-hr	0.015 g/bhp-hr
Title 13 CCR, §2423	301.7 – 603.4 bhp (225 - 450 kW)	2014 and later (Tier 4)	0.3 g/bhp-hr	0.14 g/bhp-hr	2.6 g/bhp-hr	0.01 g/bhp-hr

As presented in the table above, the proposed engine will be required to be the latest Tier level required at the time of acquisition in compliance with the requirements of this section.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

- {edited 3485} Emissions from this IC engine shall not exceed any of the following limits: 1.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- {edited 3486} Emissions from this IC engine shall not exceed 0.015 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- The engine EPA Tier rating shall be the highest applicable Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)

Title 13 CCR, Section 2423 lists diesel engine emission standards. The proposed 2,922 bhp Cummins QSK60-G6 emergency diesel IC engine (or approved equivalent) will be required to meet the latest Tier emission standard in effect at the time of acquisition as

specified in the Off-Road Compression Ignition Engine Standards for off-road engines on the applicable dates specified. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the proposed engine.

Requirements of Title 13 CCR, Section 2423						
Source	Maximum Rated Power	Model Year	NO_X	VOC	CO	PM
Title 13 CCR, §2423	≥ 1207 bhp	2011-2014 (Interim Tier 4)	0.5 g/bhp-hr	0.3 g/bhp-hr	2.6 g/bhp-hr	0.07 g/bhp-hr
Title 13 CCR, §2423	≥ 1207 bhp	2015 and later (Tier 4)	0.5 g/bhp-hr	0.14 g/bhp-hr	2.6 g/bhp-hr	0.02 g/bhp-hr

As presented in the table above, the proposed engines will be required to be the latest Tier level required at the time of acquisition in compliance with the requirements of this section.

Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {edited 3485} Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- {edited 3486} Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- The engine EPA Tier rating shall be the highest applicable Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards</u>:

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and
2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial startup testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

S-7616-38-0 (Emergency Engine Powering Electrical Generator)
S-7616-39-0 (Emergency Engine Powering Electrical Generator)
S-7616-40-0 (Emergency Engine Powering Firewater Pump)

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engines involved with this project are new stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency standby diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be included in the DOC.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency standby diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation:
c. Hours of operation for emission testing;
d. Initial startup hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency standby diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The engines associated with this project are new emergency standby engines, two of which will power electrical generators and one will power a firewater pump. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3479} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines (S-7616-38-0 and -39-0:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency standby diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {edited 3486} Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3810} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engine (S-7616-40-0):

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency standby diesel-fueled CI engine that has a rated brake horsepower greater than 50 unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate less than or equal to 0.01 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and

3. Does not operate more than 51 to 100 hours per year (upon approval by the District) for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {edited 3486} Emissions from this IC engine shall not exceed 0.015 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3809} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

IX. Recommendation

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Appendix A.

X. Billing Information

The equipment rating for some of the DOC units is not yet known. So the equipment rating will be required to be identified prior to the operation of the equipment.

APPENDIX A
Determination of Compliance Conditions

S-7616-17-0

RAIL UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF COAL, INCLUDING: ENCLOSED RAIL UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH RAILCAR UNLOADING STATION, RAIL UNLOADING BIN(S), BELT FEEDER(S), RAIL UNLOADING CONVEYOR(S) ENCLOSED IN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. After materials are unloaded from rail cars (either on site or off site facilities in the District) excess material shall be removed from exterior of rail cars such that there is no material spillage from rail car in subsequent transit. [District Rule 4102]

7. Unloading hopper shall be equipped with water/additive spray system or fabric filtration dust collector (or equivalent with prior District approval), which shall be employed as needed to control dust emissions during unloading. [District Rule 2201]

8. Operation shall include the following dust collectors serving the following operation(s): rail unloading station. [District Rule 2201]

9. Railcar unloading station shall include water spray nozzles or fabric filtration dust collector (or equivalent with prior District approval) that shall be automatically activated at or prior to unloading as necessary to prevent visible emissions. [District Rule 2201]

10. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

11. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

12. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

13. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

14. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

15. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

16. Enclosure dust suppression system water spray nozzles or fabric filtration dust collector (or equivalent with prior District approval) shall automatically operate when railcar unloading is occurring. [District Rule 2201]

17. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

18. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

19. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: rail unloading station: 20,000 cfm. [District Rule 2201]

20. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

21. PM10 emissions shall not exceed any of the following emissions for the following operation(s): rail unloading station: 4.1 lb/day. [District Rule 2201]

22. PM10 emissions shall not exceed any of the following emissions for the following operation(s): rail unloading station: 267 lb/yr. [District Rule 2201]

23. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

24. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

25. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

26. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

27. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

28. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

29. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

30. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

31. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

32. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

33. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

34. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

35. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

36. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

37. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

38. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

39. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

40. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

41. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

42. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

43. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

44. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

45. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

46. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

47. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

48. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application

instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-18-0

TRUCK UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF PETROLEUM COKE (PETCOKE) AND/OR COAL, INCLUDING: ENCLOSED TRUCK UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH TRUCK UNLOADING STATION(S), TRUCK UNLOADING BIN(S), BELT FEEDER(S), TRUCK UNLOADING CONVEYOR(S) ENCLOSED IN AN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. After materials are unloaded from rail cars excess material shall be removed from exterior of rail cars such that there is no material spillage from rail car in subsequent transit. [District Rule 4102]

7. After materials are unloaded from trailers (either on site or off site facilities in the District) excess material shall be removed from exterior of trailers such that there is no material spillage from trailers in subsequent transit. [District Rule 4102]

8. Unloading hopper shall be equipped with water/additive spray system or fabric filtration dust collector (or equivalent with prior District approval), which shall be employed as needed to control dust emissions during unloading. [District Rule 2201]

9. Operation shall include the following dust collectors serving the following operation(s): truck unloading station. [District Rule 2201]

10. Truck unloading station shall include water spray nozzles or fabric filtration dust collector (or equivalent with prior District approval) that shall be automatically activated at or prior to unloading as necessary to prevent visible emissions. [District Rule 2201]

11. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

12. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

13. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

14. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

15. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

16. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

17. Enclosure dust suppression system water spray nozzles or fabric filtration dust collector (or equivalent with prior District approval) shall automatically operate when truck unloading is occurring. [District Rule 2201]

18. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

19. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

20. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: truck unloading station: 80,000 cfm. [District Rule 2201]

21. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

22. PM10 emissions shall not exceed any of the following emissions for the following operation(s): truck unloading station: 16.5 lb/day. [District Rule 2201]

23. PM10 emissions shall not exceed any of the following emissions for the following operation(s): truck unloading station: 2,140 lb/yr. [District Rule 2201]

24. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

25. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

26. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

27. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

28. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

29. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

30. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

31. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

32. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

33. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

34. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

35. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

36. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

37. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

38. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

39. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

40. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

41. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

42. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

43. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

44. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

45. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

46. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

47. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

48. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

49. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-19-0

FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS

FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYER(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (WITH ONLY ONE OPERATING AT A SINGLE TIME), TWO ENCLOSED TRANSFER CONVEYORS; 30,000 CU FT FLUXANT SILO AND UNLOADING VENT SERVED BY A DUST COLLECTOR

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Operation shall include the following dust collectors serving the following operation(s): feedstock transfer tower 1; feedstock transfer tower 2; fluxant unloading vent. [District Rule 2201]

7. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

8. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

9. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

10. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

11. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

12. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

13. Enclosure dust suppression system water spray nozzles or fabric filtration dust collector (or equivalent with prior District approval) shall automatically operate when railcar unloading is occurring. [District Rule 2201]

14. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

15. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

16. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: feedstock transfer tower 1: 1,500 cfm; feedstock transfer tower 2: 1,500 cfm; fluxant unloading vent: 1,500 cfm. [District Rule 2201]

17. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

18. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 0.3 lb/day; feedstock transfer tower 2: 0.3 lb/day; fluxant unloading vent: 0.3 lb/day. [District Rule 2201]

19. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 40 lb/yr; feedstock transfer tower 2: 56 lb/yr; fluxant unloading vent: 28 lb/yr. [District Rule 2201]

20. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

21. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

22. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

23. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

24. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

25. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the

previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

26. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

27. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

28. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

29. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

30. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

31. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

32. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

33. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

34. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

35. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

36. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control

in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

37. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

38. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

39. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

40. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

41. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

42. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

43. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

44. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a

stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

45. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-20-0

FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION INCLUDING: CRUSHER BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH SURGE BIN(S), BELT FEEDER(S), BYPASS SCREEN(S), TWO FEEDSTOCK CRUSHERS; TWO ENCLOSED PLANT FEED CONVEYORS SERVED BY BAGHOUSE DUST COLLECTOR; MILLING AND DRYING BUILDING WITH FEEDSTOCK DRYER [USING TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR LISTED ON S-7616-26] SERVED BY BAGHOUSE DUST COLLECTOR, WITH REVERSING CONVEYOR(S), DIVERTER GATE(S), AND TWO MILLING AND DRYING SILOS

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Operation shall include the following dust collectors serving the following operation(s): feedstock bunkers; feedstock crushers. [District Rule 2201]

7. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

8. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

9. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

10. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

11. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

12. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

13. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

14. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

15. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: feedstock bunkers: 12,600 cfm; feedstock crusher: 12,600 cfm. [District Rule 2201]

16. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

17. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock bunkers: 2.6 lb/day; feedstock crusher: 2.6 lb/day. [District Rule 2201]

18. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock bunkers: 473 lb/yr; feedstock crusher: 473 lb/yr. [District Rule 2201]

19. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

20. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading.

Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

21. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

22. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

23. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

24. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

25. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

26. Feedstock dryer shall comply with the 40 CFR Part 63, Subpart UUUUU requirements. Requirements are summarized in S-7616-26. [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

27. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

28. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

29. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

30. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

31. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

32. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

33. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

34. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

35. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

36. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

37. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

38. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

39. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

40. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-21-0

GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, AND RECTISOL ACID GAS REMOVAL (AGR) UNIT WITH 600,000 GALLON METHANOL STORAGE TANK SERVED BY METHANOL VENT SCRUBBER

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

5. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

6. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

7. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

8. Scrubber shall be maintained and operated per manufacturer recommendations. [District Rule 4102]

9. Components attributed to this unit shall include those components serving the following process streams: methanol, syngas, shifted syngas, propylene, sour water, H2S-laden

methanol, CO2-laden methanol, acid gas, ammonia-laden gas, lower benzene concentration, and higher benzene concentration. [District Rule 2201]

10. Fugitive VOC emission rate from the unit shall not exceed 65.9 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: methanol, propylene, H2S-laden methanol, CO2-laden methanol, acid gas, ammonia laden gas, lower benzene concentration, and higher benzene concentration. The following control efficiencies in Tables 5-1 and 5-2 of the EPA document shall apply to those components under an LDAR program: gas valves: 92%; light liquid valves: 88%; light liquid pump seals: 100%; compressor seals: 100%; and connectors: 93%. Light liquid pump seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the pumped fluid. Compressor seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the compressed gas. [District Rules 2201 and 2410]

11. Fugitive CO and SOx emission rate from the unit shall not exceed 24.4 lb-CO/day nor 0.2 lb-SOx/day based on the component count, CO and SOx percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

12. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

13. The VOC content of the gas in the following streams shall not exceed 10% by weight: syngas, shifted syngas, sour water, acid gas, ammonia-laden gas. [District Rule 2201]

14. Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan shall be developed and submitted to the District for approval to determine sampling frequency and locations. [District Rule 2201]

15. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

16. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

17. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

18. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 or equivalent test method with prior District approval. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21 or equivalent test method with prior District approval. [District Rule 2201]

19. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

20. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21 or equivalent test method with prior District approval. [District Rule 2201]

21. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

22. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

23. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21or equivalent test method with prior District approval. If the process PRD is found to be leaking at either

inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

24. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21or equivalent test method with prior District approval. [District Rule 2201]

25. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21or equivalent test method with prior District approval; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

26. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

27. If the leak has been minimized but the leak still exceeds the applicable leak standards of this DOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

28. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the DOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

29. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

30. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

31. Sampling points adequate for extraction of grab samples shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]

32. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

33. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

34. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

35. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

36. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

37. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

38. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

39. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

40. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

41. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-22-0

GASIFICATION SOLIDS MATERIAL HANDLING AND STORAGE SYSTEM INCLUDING: GASIFICATION SOLIDS UNLOADING BUNKER (STORAGE COVER WITH ROOFING AND PARTIAL SIDING) WITH DEWATERING TANK(S), STORAGE PILE(S), RECLAIM HOPPER AND GRIZZLY, BUCKET ELEVATOR FEED CONVEYOR SERVED BY DUST COLLECTOR, ENCLOSED TRANSFER CONVEYOR (TO GASIFICATION SOLIDS TRANSFER TOWER), GASIFICATION SOLIDS TRANSFER TOWER SERVED BY DUST COLLECTOR, WITH ENCLOSED LOAD-OUT FEED CONVEYOR (TO GASIFICATION SOLIDS LOAD-OUT BUILDING); AND ENCLOSED GASIFICATION SOLIDS LOAD-OUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH GASIFICATION SOLIDS LOAD-OUT SYSTEM WITH ONE TRUCK AND ONE RAIL LOAD-OUT STATION

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Operation shall include the following dust collectors serving the following operation(s): gasification solids bucket elevator; gasification solids transfer tower; gasification solids load-out system. [District Rule 2201]

7. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

8. All material processing and conveying equipment, material storage systems, and material transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of

5% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

9. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

10. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

11. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

12. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

13. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

14. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

15. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: gasification solids bucket elevator: 3,000 cfm; gasification solids transfer tower: 3,000 cfm; gasification solids load-out system: 10,000 cfm. [District Rule 2201]

16. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

17. PM10 emissions shall not exceed any of the following emissions for the following operation(s): gasification solids bucket elevator: 0.6 lb/day; gasification solids transfer tower: 0.6 lb/day; gasification solids load-out system: 2.1 lb/day; gasification solids pad stacking: 0.2 lb/day; gasification solids pad reclaim: 0.3 lb/day. [District Rule 2201]

18. PM10 emissions shall not exceed any of the following emissions for the following operation(s): gasification solids bucket elevator: 225 lb/yr; gasification solids transfer tower: 32 lb/yr; gasification solids load-out system: 107 lb/yr; gasification solids pad stacking: 54 lb/yr; gasification solids pad reclaim: 96 lb/yr. [District Rule 2201]

19. The maximum process rates of material on a weight basis shall not exceed any of the following: gasification solids pad stacking: 943 ton/day; gasification solids pad reclaim: 943 ton/day. [District Rule 2201]

20. The maximum process rates of material on a weight basis shall not exceed any of the following: gasification solids pad stacking: 344,268 ton/yr; gasification solids pad reclaim: 344,268 ton/yr. [District Rule 2201]

21. Moisture content of the gasification solids stacking material shall be maintained at level that prevents gasification stacking material from being a source of visible emissions. [District Rule 2201] N

22. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

23. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

24. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

25. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

26. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

27. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the

previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

28. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

29. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

30. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

31. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

32. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

33. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

34. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

35. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

36. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

37. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

38. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

39. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

40. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

41. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

42. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-23-0

SULFUR RECOVERY AND TAIL GAS COMPRESSION SYSTEM CONSISTING OF SULFUR RECOVERY UNIT (SRU), A TAIL GAS UNIT (TGU) WITH A NATURAL GAS-FIRED TAIL GAS THERMAL OXIDIZER RATED UP TO 96 MMBTU/HR (OR EQUIVALENT), AND MISCELLANEOUS TANKS, COMPRESSORS, PUMPS, CONDENSERS, HEAT EXCHANGERS, PIPING

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. The sulfur recovery unit shall consist of a single train designed to include two Claus converters, two reheaters, three sulfur condensers, waste gas boiler, reaction furnace, oxygen preheater (optional), main burner, acid gas preheater, acid gas wash drum, acid gas wash drum pumps, sour water stripper (SWS) acid gas knockout drum, SWS acid gas preheater, SWS acid gas drum pumps, combustion air blower(s), sulfur degassing equipment, control instrumentation, and piping. [District Rule 2201]

10. Tail gas unit (TGU) shall be designed to include a tail gas heater, tail gas trim heater (optional), hydrogenation reactor, reactor effluent cooler, contact condenser/desuperheater, desuperheater pumps, contact condenser cooler, tailgas compressor, and thermal oxidizer. [District Rule 2201]

11. The operation of the thermal oxidizer shall include continuously recording SO2 and O2 monitors. [District Rule 2201]

12. Exhaust stack shall be equipped with adequate provisions facilitating the collection of samples consistent with EPA test methods. [District Rule 1080]

13. While burning waste gases, the thermal oxidizer firebox temperature shall be maintained above 1,200 degrees F. [District Rule 2201]

14. Permittee shall maintain accurate records of the thermal oxidizer firebox temperature, and such records shall be maintained on site readily available for District inspection. [District Rule 2201]

15. Sulfur production shall not exceed 150 short tons/day. [District Rule 2201]

16. Permittee shall maintain accurate records of daily sulfur production, and such records shall be maintained on site readily available for District inspection. [District Rule 2201]

17. Shutdown is defined as the period beginning with the termination of acid gas feed and the initiation of fuel feed gas or nitrogen purge operation feed (for the purpose of heat stripping sulfur from the internal surfaces of the SRU). [District Rule 2201]

18. Warm standby is defined as the period between shutdown and startup when the SRU feed is solely natural gas. [District Rule 2201]

19. Startup is defined as the period beginning with the introduction (or increased utilization) of natural gas to the SRU to raise the temperature of the reactor furnace and catalytic reactors to normal operating temperature (approximately 350 degrees F). Startup ends when the SRU is processing all acid gas and sour gas feeds and the desired tail gas H2S:SO2 ratio has stabilized, and the TGU off-gas is recycled back to the shift unit. [District Rule 2201]

20. Except during shutdown, warm standby, startup, and breakdown (as defined in Rule 1100) conditions, TGU tail gas shall be recycled to the shift unit, and the thermal oxidizer will be maintained in hot standby. [District Rule 2201]

21. The permittee shall, at all times including periods of startup, shutdown, and malfunction, maintain and operate the SRU and associated control equipment in a manner consistent with good air pollution control practice for minimizing emissions. [District Rule 2201]

22. In case of any exceedance of any H2S or SOx (as SO2) emission limit or any malfunction, permittee shall begin actions to minimize emissions exceedance or amount of sour gas flared, by removing high sulfur feed stocks and reducing unit rates, or by other means approved by the District. [District Rule 2201]

23. Emission rates from the tail gas thermal oxidizer shall not exceed the following: NOx: 0.24 lb/MMBtu; CO: 0.20 lb/MMBtu; VOC: 0.0055 lb/MMBtu; PM10: 0.0076 lb/MMBtu. [District Rule 2201]

24. SOx (as SO2) emissions from the tail gas thermal oxidizer shall not exceed 0.00204 lb/MMBtu for the disposal of SRU startup gas, 2.0 lb/hr for the disposal of the process vent gas, 75.0 lb/hr during plant shutdown for passivation, nor 125.0 lb/hr for presulfiding of catalyst. [District Rule 2201]

25. The thermal oxidizer shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

26. The thermal oxidizer firing rate shall not exceed 13.0 MMBtu/hr (HHV) of natural gas from normal operation (for the disposal of process vent gas). Pre-startup firing of natural gas in the SRU reactor furnace for system warmup, with the products of combustion vented to the thermal oxidizer shall not exceed 80.0 MMBtu/hr (HHV). Likewise, post-shutdown firing of natural gas in the SRU for plant maintenance shall not exceed 80.0 MMBtu/hr (HHV). [District Rule 2201]

27. The thermal oxidizer shall not exceed 108,082 MMBtu for normal operation (for the disposal of process vent gas) per calendar year, nor 3,840 MMBtu per calendar year for SRU startup operation (for the disposal of SRU startup gas), nor 1,920 MMBtu per calendar year for SRU maintenance. [District Rules 2201 and 2410]

28. The annual heat input of the unit (natural gas fired in the thermal oxidizer plus additional natural gas fired in the SRU reaction furnace) shall not exceed 113.8 billion Btu/yr. [District Rule 2201]

29. A non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter, or equivalent method as approved by the District, to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 2410]

30. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070 and 2201]

31. During SRU shutdown, SRU tail gas shall be directed to the TGU provided the O2 content of the SRU tail gas is less than or equal to 0.5% by weight as measured with portable O2 analyzer or equivalent CO value as measured by the CO/CO2 analyzer provided the exotherm across the TGU catalytic reactor does not become excessive. During the final 12 hours of SRU shutdown, or should the TGU catalytic reactor temperature rise above 750 degrees F, the SRU tail gas may bypass the TGU and be introduced directly to the thermal oxidizer. [District Rule 2201]

32. During SRU warm standby, SRU tail gas may bypass the TGU and be introduced directly to the thermal oxidizer. [District Rule 2201]

33. During SRU startup (after being completely down), SRU tail gas may bypass the TGU and be introduced directly to the thermal oxidizer provided the O2 content of the SRU tail is greater than zero percent by volume as measured with portable O2 analyzer or equivalent CO value as measured by the CO/CO2 analyzer. The duration in which the TGU is bypassed shall not exceed 72 hours. [District Rule 2201]

34. During SRU startup (after being in warm standby), SRU tail gas shall be directed to the TGU. Within 24 hours of directing the SRU tail gas to the TGU, the TGU tail gas shall be recycled to the shift unit. [District Rule 2201]

35. All required source testing shall conform to the compliance testing procedures described in District Rule 1081. [District Rule 1081]

36. Within 90 days of startup and annually thereafter, operator shall conduct source testing of the thermal oxidizer to demonstrate compliance with SOx, NOx, CO and VOC emission limits. [District Rules 2201]

37. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

38. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

39. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

40. Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results to determine compliance with the conditions of this FDOC shall be maintained. The operator shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2201]

41. Particulate matter emissions shall not exceed 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201 and 4301, 5.1 and 5.2.3]

42. For the sulfur recovery unit thermal oxidizer, operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 10 ppm by volume (dry basis) of H2S at zero percent excess air (moving 3-hour average). [District Rule 2201]

43. For the sulfur recovery unit, a continuous emissions monitoring system shall be installed, calibrated, operated, and reported. Operator shall report all 3-hour periods during which the average concentration of H2S as measured by the H2S continuous monitoring system exceeds 10 ppm (dry basis, zero percent excess air). [District Rule 2201]

44. Operator shall determine compliance with the SO2 and H2S standard using EPA Method 3, EPA Method 6, and EPA Method 15. [District Rule 2201]

45. Components attributed to this unit shall include those components serving the following process streams: sulfur and SRU tail gas unit (TGU) process gas. [District Rule 2201]

46. Fugitive CO and SOx emission rate from the unit shall not exceed 2.7 lb-CO/day and 0.4 lb-SOx/day based on the component count, CO and SOx percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

47. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

48. The VOC content of the gas in the following streams shall not exceed 10% by weight: sulfur, SRU tail gas unit process gas. [District Rule 2201]

49. Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan shall be developed and submitted to the District for approval to determine sampling frequency and locations. [District Rule 2201]

50. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

51. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

52. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

53. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

54. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

55. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21 or equivalent test method with prior District approval. [District Rule 2201]

56. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

57. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

58. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21or equivalent test method with prior District approval. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

59. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21or equivalent test method with prior District approval. [District Rule 2201]

60. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21 or equivalent test method with prior District approval; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

61. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

62. If the leak has been minimized but the leak still exceeds the applicable leak standards of this FDOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

63. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the FDOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

64. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

65. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

66. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

67. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

68. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

69. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

70. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

71. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

77. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

78. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

79. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-24-0

CO2 RECOVERY (CAPTURE, COMPRESSION, AND TRANSPORTATION) AND VENT SYSTEM FOR EMERGENCY RELEASES OF A STREAM OF PRIMARILY CO2 FROM THE ACID GAS REMOVAL UNIT

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Emission rates from the vent stream shall not exceed 496.3 lb-CO/hour, 28.2 lb-VOC/hour, 10.6 lb-COS/hour, nor 6.0 lb-H2S/hour. Compliance with these rates shall be demonstrated by measuring the vent stream flowrate and the concentration of these constituents in the vent stream. [District Rule 2201]

7. Venting shall only be allowed when compression or transportation system is unavailable or CO2 delivery system is unavailable due to cold gasification block startup, CO2 compressor unplanned outage, CO2 pipeline unplanned outage, or CO2 off-taker unable to accept, and emissions from such venting shall not exceed 125.1 tons-CO/yr, 3.8 tons-VOC/yr, 2.7 tons-COS/yr, nor 1.5 tons-H2S/yr per rolling 12-month period. Compliance with these rates shall be demonstrated by measuring the vent stream flowrate and the concentration of these constituents in the vent stream. [District Rules 2201 and 2410]

8. Venting shall not exceed 193,394 tons/yr of CO2 per rolling 12-month period. [District Rules 2201and 2410]

9. Vent stream concentration shall not exceed 1,000 ppm-CO, 44 ppm-VOC, 10 ppm-COS, nor 10 ppm-H2S. [District Rules 2201 and 2410]

10. Emission rates from the vent stream shall not exceed 11,911 lb-CO/day nor 677 lb-VOC/day. [District Rules 2201 and 2410]

11. A non-resettable, totalizing mass or volumetric flow meter to measure the amount of gas vented shall be installed, utilized and maintained. [District Rules 2201 and 2410]

12. Period of venting shall be reported to the District by the following working day, including the duration of the venting event and the vent gas composition observed. [District Rule 2201]

13. Hazardous Air Pollutant (HAP) emissions for the stationary source shall not exceed 25 ton/year for all HAPs nor 10 ton/year for any single HAP. [District Rule 4002]

14. Permittee shall conduct an initial speciated HAPs and total VOC source test for the CO2 recovery and vent system by District witnessed in situ sampling of vented stream by a qualified independent source test firm. The permittee shall determine the total HAPs emissions rate, the single highest HAP emission rate, and the VOC mass emission during the source test. Initial compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates determined during initial compliance source testing and the correlation between VOC emissions and HAP(s). Ongoing compliance shall be determined using mass flow and VOC sampling during venting occurrences as described in the condition below. [District Rule 4002]

15. The vent stream composition of CO, VOC, H2S, COS, and the HAPs identified in the initial speciated HAPs and total VOC source test, shall be measured during each venting occurrence exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District in writing. [District Rule 2201]

16. Permittee shall monitor the CO2 concentration in the CO2 stream prior to the custody transfer. The permittee shall calculate the CO2e emissions for each calendar month and shall maintain such records of onsite for District review. [District Rule 2410]

17. Permittee shall maintain records of the CO2 concentration of the CO2 stream prior to custody transfer and records of venting events including the flowrate of the vent stream and reasons for venting event, and such records shall be retained on site readily available for District inspection. [District Rules 2201 and 2410]

18. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

19. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed

surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

20. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

21. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

22. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

23. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

24. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

25. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

26. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

27. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for

those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-25-0

230 MMBTU/HR NATURAL GAS-FIRED AUXILIARY BOILER EQUIPPED WITH LOW-NOX BURNER WITH FLUE GAS RECIRCULATION (FGR) AND SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The unit shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410, 4320, 2410]

12. The boiler shall be equipped with an economizer and condensate recovery system. [District Rules 2201 and 2410]

13. Duration of startup and shutdown of heater shall not exceed 2 hours each per occurrence. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. The operator shall maintain records of the duration of startup and shutdown. [District Rules 4305, 4306, and 4320]

14. Emissions from this unit, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 5.0 ppmvd @ 3% O2 or 0.006 lb/MMBtu, SOx (as SO2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50.8 ppmvd @ 3% O2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

15. The maximum allowable heat input of the boiler shall not exceed 213 MMBtu/hr (HHV). [District Rule 2201]

16. The annual heat input of the unit shall not exceed 466.0 billion Btu per calendar year. [District Rules 2201 and 2410]

17. A non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter (or equivalent as approved by the District) to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 2410]

18. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070 and 2201]

19. The operator shall tune the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to

verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown. [District Rule 2410]

20. {4063} The permittee shall monitor and record the stack concentration of NOX, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305 and 4306]

21. {4064} If either the NOX or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305 and 4306]

22. {4065} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305 and 4306]

23. {4066} The permittee shall maintain records of: (1) the date and time of NOX, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305 and 4306]

24. This unit shall be tested for compliance with the NOx and CO emissions limits within 60 days of initial startup and at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

25. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

26. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

27. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

28. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

29. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

30. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rules 4305, 4306 and 4320]

31. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

32. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of

performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

33. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

34. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

35. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

36. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306, and 4320]

37. Permittee shall comply with all applicable NSPS requirements, including monitoring, notification and reporting requirements as described in 40 CFR 60 Subparts A and Db. [District Rule 4001]

38. Permittee shall submit to the EPA Regional Administrator for approval a plan that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b (j). This plan shall be submitted to the EPA Regional Administrator for approval within 360 days of the initial startup of the affected facility. [District Rule 4001]

39. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

40. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission

rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

41. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

42. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

43. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

44. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

45. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

46. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

47. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

48. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

49. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

50. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

51. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

52. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

53. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-26-0

431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI M501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE, AND FEEDSTOCK DRYER VENT (USING TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively

specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The owner/operator of the facility shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. [District Rule 2201]

12. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201]

13. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. Two commissioning periods will occur: when firing on natural gas and when firing on hydrogen-rich fuel. [District Rule 2201]

14. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

15. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

16. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

17. During the commissioning period when firing on natural gas, emission rates from the CTG/HRSG stack shall not exceed any of the following limits: NOx (as NO2) - 391.20 lb/hr; SOx - 4.80 lb/hr; PM10 - 15.00 lb/hr; CO - 2,270.00 lb/hr; or VOC (as methane) - 65.00 lb/hr. During the commissioning period when firing on hydrogen-rich fuel, emission rates from the CTG shall not exceed any of the following limits: NOx (as NO2) - 99.04 lb/hr; SOx - 5.00 lb/hr; PM10 - 15.00 lb/hr; CO - 1622.60 lb/hr; or VOC (as methane) - 35.12 lb/hr. [District Rule 2201]

18. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with the condition above through the use of properly operated and maintained continuous emissions monitors and recorders as specified in this document. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

19. The continuous emissions monitors specified in these conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

20. During the commissioning period on natural gas, this unit shall not fire more than 456 total hours without abatement of emissions by the SCR system and/or the oxidation catalyst. During the commissioning period on hydrogen-rich fuel, this unit shall not fire more than 50 total hours without abatement of emissions by the SCR system and/or the oxidation catalyst and shall not fire more than 200 total hours without the partial operation of the SCR system and/or the oxidation catalyst. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the firing hours without abatement shall expire. Records of the commissioning hours of operation for the unit shall be maintained. [District Rule 2201]

21. The total mass emissions of NOx, SOx, PM10, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in this document. The total mass emissions of CO that are emitted during the commissioning period shall not exceed 332.1 tons-CO. NOx and CO total mass emissions shall be determined from CEMs data and SOx, PM10, and VOC total mass emissions may be calculated. [District Rule 2201]

22. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

23. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

24. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this DOC when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

25. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

26. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

27. This unit shall be fired on hydrogen-rich fuel or on PUC-regulated natural gas backup fuel. Firing on backup PUC-quality natural gas shall only occur during CTG startups, CTG shutdowns, or during periods of unplanned equipment outages (with firing on natural gas not to exceed 336 hours per calendar year). [District Rule 2201 and 2410]

28. This unit shall be fired on hydrogen-rich fuel with a sulfur content no greater than 10 ppmv, or on PUC-regulated natural gas with a sulfur content of no greater than 0.75 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rules 2201 and 2410, and 40 CFR 60.4330(a)(2)]

29. During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 25.0 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 3.5 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 18.3 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 12.9 lb/hr; or SOx (as SO2) - 4.1 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. During normal operation (excluding startup and shutdown), emission rate from the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 4.4 lb/hr and 2.5 ppmvd-NOx @ 15% O2 (1-hour average); VOC (as methane) - 0.6 lb/hr and 1.0 ppmvd-VOC @ 15% O2; CO - 3.2 lb/hr and 3.0 ppmvd-CO @ 15% O2; PM10 - 1.4 lb/hr; or SOx (as SO2) - 0.9 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

31. During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on natural gas shall not exceed any of the following: NOx (as NO2) - 34.1 lb/hr and 4.0 ppmvd-NOx @ 15% O2; VOC (as methane) - 5.9 lb/hr and 2.0 ppmvd-VOC @ 15% O2; CO - 26.0 lb/hr and 5.0 ppmvd-CO @ 15% O2; PM10 - 15.0

lb/hr; or SOx (as SO2) - 4.7 lb/hr. All pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

32. Ammonia (NH3) emissions from CTG/HRSG stack shall not exceed either of the following limits: 18.5 lb/hr or 5.0 ppmvd @ 15% O2 (based on a 24 hour rolling average). Ammonia emissions from feedstock dryer stack shall not exceed either of the following limits: 3.2 lb/hr or 5.0 ppmvd @ 15% O2 (based on a 24 hour rolling average). . [District Rule 2201]

33. During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 107.20 lb/hr, SOx - 2.40 lb/hr, PM10 - 15.00 lb/hr, CO - 2,270.00 lb/hr, or VOC - 65.00 lb/hr, based on one-hour averages. During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 381.2 lb/day, SOx - 10.7 lb/day, PM10 - 59.7 lb/day, CO - 3,385.0 lb/day, or VOC - 67.7 lb/day. [District Rule 2201]

34. During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 15.10 lb/hr, SOx - 0.30 lb/hr, PM10 - 0.90 lb/hr, CO - 147.40 lb/hr, or VOC - 1.90 lb/hr, based on one-hour averages. During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 49.0 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 317.8 lb/day, or VOC - 5.2 lb/day. [District Rule 2201]

35. During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 122.0 lb/hr, SOx - 2.7 lb/hr, PM10 - 15.0 lb/hr, CO - 2,270.0 lb/hr, or VOC - 64.8 lb/hr, based on one-hour averages. During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 766.6 lb/day, SOx - 21.9 lb/day, PM10 - 127.0 lb/day, CO - 8,437.0 lb/day, or VOC - 193.9 lb/day. [District Rule 2201]

36. During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 9.4 lb/hr, SOx - 0.3 lb/hr, PM10 - 0.9 lb/hr, CO - 11.5 lb/hr, or VOC - 0.7 lb/hr, based on one-hour averages. During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 37.6 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 46.0 lb/day, or VOC - 2.8 lb/day. [District Rule 2201]

37. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to normal operations emission compliance. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status when emissions exceed normal operating limits, by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

38. For CTG/HRSG, the duration of each startup event shall not exceed 4.5 hours, and the duration of each shutdown event shall not exceed 9.0 hours. For feedstock dryer, the duration of each startup event shall not exceed 4.0 hours, and the duration of each

shutdown event shall not exceed 4.0 hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. Daily emissions from the CTG/HRSG stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 600.0 lb/day; CO - 439.2 lb/day; VOC - 84.0 lb/day; PM10 - 309.6 lb/day; SOx (as SO2) - 98.4 lb/day, or NH3 - 444.0 lb/day. [District Rule 2201]

41. Daily emissions from the CTG/HRSG stack when firing on natural gas on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 818.4 lb/day; CO - 624.0 lb/day; VOC - 141.6 lb/day; PM10 - 360.0 lb/day; SOx (as SO2) - 112.8 lb/day, or NH3 - 379.2 lb/day. [District Rule 2201]

42. Daily emissions from the feedstock dryer stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 105.6 lb/day; CO - 76.8 lb/day; VOC - 14.4 lb/day; PM10 - 33.6 lb/day; SOx (as SO2) - 21.6 lb/day, or NH3 - 76.8 lb/day. [District Rule 2201]

43. Annual emissions from the CTG/HRSG stack, calculated on a twelve-consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 212,953 lb/year; SOx (as SO2) - 34,445 lb/year; PM10 - 107,813 lb/year; CO - 177,980 lb/year; or VOC - 30,506 lb/year. [District Rule 2201]

44. Annual emissions from the feedstock dryer stack, calculated on a twelve-consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 33,773 lb/year; SOx (as SO2) - 5,605 lb/year; PM10 - 11,257 lb/year; CO - 25,528 lb/year; or VOC - 4,816 lb/year. [District Rule 2201]

45. Each one-hour period shall commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one-hour periods. Each one-hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

46. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

47. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1.) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a =

average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 2201]

48. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

49. Hazardous Air Pollutant (HAP) emissions for the stationary source shall not exceed 25 ton/year for all HAPS nor 10 ton/year for any single HAP. [District Rule 4002]

50. Permittee shall conduct an initial speciated HAPs and total VOC source test for the combustion turbine generator, by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. The permittee shall correlate the total HAPs emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the combustion gas turbine determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

51. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after the conclusion of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

52. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

53. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

54. The sulfur content of the natural gas fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and

monitored weekly thereafter. If the sulfur content is demonstrated to be less than 0.75 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

55. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia - EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

56. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

57. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

58. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1080]

59. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

60. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

61. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and

shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

62. One CEMS shall continuously measure and record the parameters required in the condition above for both the CTG/HRSG exhaust and the feedstock dryer exhaust. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

63. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

64. The NOx, CO and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

65. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

66. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

67. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

68. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NOx concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4380(b)(1)]

69. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

70. The permittee shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

71. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

72. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

73. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

74. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

75. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

76. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

77. No less than 90 percent (12-month rolling average, by weight) of the pre-combustion carbon in the gasified fuel stream shall be removed. [District Rule 2410]

78. At least once every month, the operator shall monitor the syngas flow rate and the CO, CO2, and CH4 concentration in the gas upstream and downstream of the acid gas removal (AGR) unit using an analytical process gas measurement system that complies with a District-approved monitoring plan. [District Rules 1081 and 2410]

79. The permittee shall maintain records of the CO, CO2, and CH4 concentration upstream and downstream of the AGR unit, the syngas flow rate, and the carbon capture percentage. [District Rule 2410]

80. Except as noted below, separated pre-combustion CO2 stream shall be transported to Occidental of Elk Hills (OEHI) in compliance with the latest approved OEHI CO2 Project Monitoring, Reporting and Verification (MRV) Plan, or equivalent, that has been approved by the responsible state agency to assure sequestration of the CO2 transported to and used by the OEHI CO2 EOR Project. Venting of the CO2 stream shall only be allowed when compression or transportation system is unavailable or CO2 delivery system is unavailable due to cold gasification block startup, CO2 compressor unplanned outage, CO2 pipeline unplanned outage, or CO2 off-taker unable to accept. Such venting shall not exceed 193,394 ton/yr CO2 per rolling 12-month period. [District Rule 2410]

81. CO2e emissions from entire stationary source (S-7616) shall not exceed 593,965 tons per rolling 12-month period. The permittee shall calculate the CO2e emissions for each calendar month and shall maintain such records onsite for District review. Calculations shall be based on: monthly fuel consumption at the facility and emission factors of fuel (natural gas and diesel CO2e emission factors shall be based on accepted emission factors and syngas CO2e factors shall be based on the amount of carbon in the syngas based on latest monitoring data used to demonstrate carbon removal efficiency); CO2 vent flowrate and the latest monitoring data; nitric acid emission rate (lb-N2O/ton of HNO3 produced) from the latest source test and production; recharge records of circuit breakers; and fugitive emission calculations based on component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components; and urea absorber hours of operation and vendor guarantee of CO2e emission factor. [District Rule 2410]

82. The circuit breakers at the facility shall be enclosed-pressure SF6 circuit breakers with a leak detection system that consists of a density alarm that provides a warning prior to a total of 10 percent of the SF6 (by weight) of the circuit breakers has escaped. Within 30 days of the alarm, circuit breakers shall be replaced or the leak shall be repaired to prevent further release of the gas. [District Rule 2410]

83. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

84. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

85. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

86. During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack and the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: filterable particulate matter: 0.07 lb-MWh; hydrogen chloride: 2.0E-3 lb/MWh or sulfur dioxide: 0.4 lb/MWh; mercury: 0.003 lb/GWh based on a 30-day rolling average. [District Rules 2201 and 4002 and 40 CFR 63 Subpart UUUUU]

87. Filterable particulate matter shall be measured using a continuous parametric monitoring system (PM CPMS). Sulfur dioxide shall be measured using SO2 CEMS. Mercury shall be measured using a sorbent trap monitoring system. Other approved measurement methods may be used with prior District approval. [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

88. The permittee shall comply with the work practice standards for the CTG as specified in Table 3 to Subpart UUUUU of Part 63. The permittee shall conduct a tune-up of the CTG burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

89. The permittee must operate all continuous monitoring system (CMS) for the CTG during startup. Startup means either the first-ever firing of fuel in a unit for the purpose of producing electricity, or the firing of fuel in a unit after a shutdown event for any purpose. Startup ends when any of the steam from the unit is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, permittee must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once permittee converts to firing coal, residual oil, or solid oil-derived fuel, permittee must engage all of the applicable control technologies except SCR. Permittee must start SCR system, if present, appropriately to comply with relevant standards applicable during normal operation. Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. Permittee must keep records during periods of startup. Permittee must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

90. Permittee must operate all continuous monitoring system (CMS) for the CTG during shutdown. Shutdown means the cessation of operation of a unit for any purpose. Shutdown begins either when none of the steam from the unit is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the turbine. Shutdown ends when there is both no electricity being generated and no fuel being fired in the unit. During shutdown, permittee must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart.

Permittee must keep records during periods of startup. Permittee must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

91. The permittee shall maintain the 30-operating day rolling average particulate matter continuous parametric monitoring system (PM CPMS) output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s) in compliance with the requirements of Table 5 to Subpart UUUUU of Part 63 (Operating Limits for EGUs). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

92. The permittee shall demonstrate compliance with the performance testing requirements of Table 5 to Subpart UUUUU of Part 63 (Performance Testing Requirements). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

93. The permittee shall demonstrate compliance with requirements for establishing PM CPMS operating limits of Table 6 to Subpart UUUUU of Part 63 (Establishing PM CPMS Operating Limits). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

94. The permittee shall demonstrate continuous compliance with the applicable emissions limits, operating limits, or work practice standards in accordance with the Table 7 to Subpart UUUUU of Part 63 (Demonstrating Continuous Compliance). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

95. In accordance with Table 8 to Subpart UUUUU of Part 63 (Reporting Requirements), permittee must submit a compliance report containing: a) Information required in § 63.10031(c)(1) through (4); and b) If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c). If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e). The report shall be submitted semiannually according to the requirements in § 63.10031(b). [District Rule 4002 and 40 CFR 63 Subpart UUUUU]

96. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control

in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

97. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

98. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

99. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

100. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

101. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

102. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

103. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

104. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a

stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

105. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-27-0

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING GASIFICATION BLOCK AND PROCESS UNITS

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

6. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

7. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration excluding condensed water vapor. [District Rule 4201]

10. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

11. Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

12. Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]

13. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

14. Cooling tower circulation water flow rate shall not exceed 162,582 gallons per minute nor 81.1 billion gallons per calendar year. [District Rule 2201]

15. Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps. [District Rule 2201]

16. PM10 emission rate from the cooling tower shall not exceed 87.9 lb/day. [District Rule 2201]

17. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

18. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

19. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

20. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

21. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

22. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless

specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

23. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

24. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

25. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

26. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

27. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

28. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-28-0

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING AIR SEPARATION UNIT

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

6. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

7. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration excluding condensed water vapor. [District Rule 4201]

10. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

11. Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

12. Total dissolved solids (TDS) in circulating water shall not exceed 2,000 mg/liter. [District Rule 2201]

13. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

14. Cooling tower circulation water flow rate shall not exceed 44,876 gallons per minute nor 22.4 billion gallons per calendar year. [District Rule 2201]

15. Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps. [District Rule 2201]

16. PM10 emission rate from the cooling tower shall not exceed 5.4 lb/day. [District Rule 2201]

17. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

18. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

19. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

20. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

21. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

22. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless

specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

23. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

24. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

25. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

26. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

27. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

28. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-29-0

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING POWER BLOCK

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

6. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

7. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration excluding condensed water vapor. [District Rule 4201]

10. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

11. Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

12. Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]

13. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

14. Cooling tower circulation water flow rate shall not exceed 95,500 gallons per minute nor 49.7 billion gallons per calendar year. [District Rule 2201]

15. Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps. [District Rule 2201]

16. PM10 emission rate from the cooling tower shall not exceed 51.6 lb/day. [District Rule 2201]

17. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

18. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

19. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

20. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

21. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

22. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless

specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

23. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

24. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

25. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

26. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

27. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

28. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-30-0

4,000 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.5 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING GASIFICATION BLOCK (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

10. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]

11. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]

12. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]

13. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

14. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

15. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2 and 40 CFR 60.18(c)(2)]

16. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

17. Maximum amount of gas combusted in the flare during planned flaring shall not exceed any of the following: 21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; 43,434 MMBtu/yr of shifted gas. [District Rules 2201 and 2410]

18. Emissions from the flare, during the non-emergency combustion of natural gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; CO: 0.08 lb/MMBtu; or SOx: 0.00214 lb/MMBtu. [District Rule 2201]

19. Emissions from the flare, during the non-emergency combustion of syngas and waste gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.008 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0015 lb/MMBtu; CO: 2.0 lb/MMBtu on unshifted syngas and 0.37 lb/MMBtu on shifted syngas; or SOx: 0.002 lb/MMBtu. [District Rule 2201]

20. {279} Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

21. Emissions from the planned flaring shall not exceed any of the following: NOx: 2,399.0 lb/day; SOx: 79.7 lb/day; PM10: 238.2 lb/day; CO: 18,282.5 lb/day; or VOC: 51.2 lb/day. [District Rule 2201]

22. Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

23. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

24. No less than 90 days prior to operation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

25. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

26. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

27. Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

28. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

30. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

31. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

32. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

33. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

34. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

35. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

36. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

37. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

38. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

39. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

40. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

41. No less than 90 days prior to installation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

42. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0% by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

43. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

44. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

45. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

46. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

47. The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

48. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

49. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

50. Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

51. Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

52. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201, 4311, 40 CFR 60.18]

53. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

54. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

55. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

56. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

57. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

58. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

59. {3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

60. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

61. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

62. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

63. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

64. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

65. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

67. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

68. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

69. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-31-0

2,100 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

10. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]

11. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]

12. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]

13. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

14. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

15. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2 and 40 CFR 60.18(c)(2)]

16. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

17. Maximum amount of gas combusted in the flare shall not exceed 2,628 MMBtu/yr during pilot gas combustion nor 1,440 MMBtu/yr during other non-emergency combustion. [District Rule 2201 and 2410]

18. During planned flaring events, no more than 36 MMBtu/hr shall be combusted (plus no more than 0.3 MMBtu/hr for pilot gas). [District Rules 2201 and 2410]

19. Emissions from the flare shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

20. SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 18.4 lb/hr during other non-emergency combustion. [District Rule 2201]

21. {279} Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

22. Other than the flaring limited in the conditions above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

23. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

24. No less than 90 days prior to operation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

25. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

26. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

27. Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

28. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs

first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

30. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

31. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

32. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

33. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

34. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

35. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

36. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

37. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

38. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

39. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

40. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

41. No less than 90 days prior to installation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

42. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0% by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

43. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

44. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

45. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

46. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

47. The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

48. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

49. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

50. Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

51. Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

52. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201, 4311, 40 CFR 60.18]

53. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

54. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

55. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

56. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

57. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

58. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

59. {3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

60. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

61. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

62. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

63. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

64. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

65. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in

Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

67. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

68. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

69. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-32-0

5,500 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING RECTISOL UNIT (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410]

10. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]

11. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]

12. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]

13. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

14. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

15. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2 and 40 CFR 60.18(c)(2)]

16. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

17. Maximum amount of gas combusted in the flare shall not exceed 2,628 MMBtu/yr during pilot gas combustion, nor 3,440 MMBtu/day nor 17,200 MMBtu/yr during other non-emergency combustion. [District Rules 2201 and 2410]

18. During planned flaring events, no more than 430 MMBtu/hr shall be combusted (plus no more than 0.3 MMBtu/hr for pilot gas). [District Rule 2201 and 2410]

19. Emissions from the flare during pilot and other non-emergency operation shall not exceed any of the following: PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

20. SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 15.0 lb/hr during other non-emergency combustion. [District Rule 2201]

21. {279} Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

22. Other than the flaring limited in the conditions above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

23. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

24. No less than 90 days prior to operation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

25. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

26. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

27. Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

28. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs

first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

30. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

31. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

32. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

33. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

34. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

35. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

36. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

37. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

38. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

39. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

40. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

41. No less than 90 days prior to installation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

42. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0% by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

43. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

44. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

45. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

46. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

47. The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

48. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

49. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

50. Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

51. Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

52. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201, 4311, 40 CFR 60.18]

53. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

54. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

55. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

56. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

57. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

58. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

59. {3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

60. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

61. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

62. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

63. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

64. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

65. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in

Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

67. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

68. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

69. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-33-0

AMMONIA SYNTHESIS UNIT CONSISTING OF: ONE 56.0 MMBTU/HR NATURAL GAS-FIRED AMMONIA STARTUP HEATER EQUIPPED WITH FOUR LOW-NOX BURNERS, EACH RATED AT 14 MMBTU/HR (OR EQUIVALENT); AMMONIA SYNTHESIS CONVERTER; SEPARATORS; ELECTRIC SYNGAS COMPRESSOR; ELECTRIC AMMONIA REFRIGERATION COMPRESSOR; AMMONIA ACCUMULATOR; AMMONIA REFRIGERATION SYSTEM; COLD LIQUID AMMONIA STORAGE SYSTEM; AMMONIA RECOVERY UNIT

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-21, -23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 2,455 lb, 2nd quarter: 2,455 lb, 3rd quarter: 2,455 lb, and 4th quarter: 2,455 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 12,416 lb, 2nd quarter: 12,416 lb, 3rd quarter: 12,416 lb, and 4th quarter: 12,416 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively

specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. Heater shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410, and 4320]

12. Duration of startup and shutdown of heater shall not exceed 2 hours each per occurrence. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. The operator shall maintain records of the duration of startup and shutdown. [District Rules 4305, 4306, and 4320]

13. Emissions from heater, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu, SOx (as SO2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50 ppmvd @ 3% O2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

14. The annual heat input of the heater shall not exceed 7.84 billion Btu per calendar year. [District Rules 2201 and 2410]

15. Pursuant to Rule 4320, the operator shall pay an annual emission fee to the District for NOx emissions from this heater for the previous calendar year. Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

16. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rule 2201]

17. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070, 2201]

18. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring

shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

19. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

20. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

21. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

22. This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

23. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

24. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

25. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

26. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

27. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

28. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rules 4305, 4306 and 4320]

29. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

30. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306, and 4320]

31. Components attributed to this unit shall include those components serving the following process streams: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification compressors, urea CO2 compressors, NO2, nitric acid (HNO3), and PSA off gas, . [District Rule 2201]

32. Fugitive emission rates for this unit shall be based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification compressors, urea CO2 compressors, NO2, nitric acid (HNO3), and PSA off gas. The following control efficiencies in Tables 5-1 and 5-2 of the EPA document shall apply to those components

under an LDAR program: gas valves: 92%; light liquid valves: 88%; light liquid pump seals: 100%; compressor seals: 100%; and connectors: 93%. Light liquid pump seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the pumped fluid. Compressor seals shall have a dual mechanical seal with barrier fluid maintained at a higher pressure than the compressed gas. [District Rules 2201 and 2410]

33. Fugitive CO emission rate from the unit shall not exceed 0.7 lb/day based on the component count, CO percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

34. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

35. The VOC content of the gas in the following streams shall not exceed 10% by weight: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification compressors, urea CO2 compressor, NO2, nitric acid (HNO3), and PSA off gas. [District Rule 2201]

36. Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan shall be developed and submitted to the District for approval to determine sampling frequency and locations. [District Rule 2201]

37. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

38. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

39. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

40. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

41. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible

components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21 or equivalent method with prior District approval. [District Rule 2201]

42. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

43. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

44. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21or equivalent test method with prior District approval. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

45. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21 or equivalent test method with prior District approval. [District Rule 2201]

46. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21 or equivalent test method with prior District approval; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

47. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

48. If the leak has been minimized but the leak still exceeds the applicable leak standards of this DOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

49. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the DOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

50. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

51. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

52. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

53. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

54. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

55. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

56. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

57. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

58. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

59. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

60. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

61. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

62. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

63. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

64. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

65. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

66. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-34-0

UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS VENTED TO THE UREA ABSORBER VENT; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 2410]

7. Operation shall include the following dust collectors serving the following operations: urea bucket elevator. [District Rule 2201]

8. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

9. All processing and conveying equipment, storage systems, and transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rule 2201]

10. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rule 2201]

11. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

12. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

13. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

14. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

15. Permittee shall maintain daily records of the hours of operation and weight of material processed and records shall be made available for District inspection upon request. [District Rule 2201]

16. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: urea bucket elevator: 1,500 cfm. [District Rule 2201]

17. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

18. PM10 emissions shall not exceed any of the following emissions for the following operations: urea bucket elevator: 0.3 lb/day. [District Rule 2201]

19. PM10 emissions shall not exceed any of the following emissions for the following operations: urea bucket elevator: 113 lb/yr. [District Rule 2201]

20. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

21. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

22. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

23. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

24. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 1081]

25. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

26. Source testing to determine opacity shall be conducted using EPA method 9. [District Rule 1081]

27. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 1081]

28. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 1081]

29. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 1081]

30. Permittee shall maintain a logbook (written or electronic) with the records specified in this document on-site and make it available upon request. [District Rule 1081]

31. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

32. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

33. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

34. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

35. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

36. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

37. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

38. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

39. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit

Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

40. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

41. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-35-0

NITRIC ACID UNIT FOR THE PRODUCTION OF NITRIC ACID FROM AMMONIA OXIDATION, NITRIC OXIDE OXIDATION, AND ABSORPTION SERVED BY: SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX, AND TERTIARY CATALYTIC DECOMPOSITION TO CONTROL N2O

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,316 lb, 2nd quarter: 74,316 lb, 3rd quarter: 74,316 lb, and fourth quarter: 74,316 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

7. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, 10% opacity. [District Rules 2201]

8. The production rate of nitric acid (expressed as 100 percent nitric acid) shall not exceed 501 tons of nitric acid in one day nor 168,086 tons of nitric acid in any calendar year. [District Rule 2201]

9. The selective catalytic reduction system shall be operated at all times that nitric acid production is occurring. [District Rule 2201]

10. During the commissioning period, emission rates from the nitric acid unit shall not exceed not exceed 504 lb-NOx/day. [District Rule 2201]

11. The total mass emissions that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in this document. [District Rule 2201]

12. The owner/operator of the facility shall minimize the emissions from the emissions unit to the maximum extent possible during the commissioning period. [District Rule 2201]

13. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the emissions unit. [District Rule 2201]

14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the emissions unit is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

15. The permittee shall submit a plan to the District at least four weeks prior to the first operation of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. [District Rule 2201]

16. The nitric acid unit shall not discharge into the atmosphere any gases which contained NOx, expressed as NO2, in exceed of 0.20 lb-NOx per ton of nitric acid produced (24-hour rolling average, expressed as 100 percent nitric acid), except during commissioning. [District Rule 2201 and 40 CFR 60 Subpart Ga]

17. NOx emissions from the nitric acid unit shall not exceed 100.2 lb-NOx/day, except during commissioning. [District Rule 2201]

18. NOx emissions from the nitric acid unit shall not exceed 33,617 lb-NOx per calendar year. [District Rule 2201]

19. The ammonia slip emissions (NH3) shall not exceed either of the following limits: 1.0 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]

20. N2O emission rate shall not exceed 0.54 lb-N2O per ton of HNO3 produced (based on an annual average). [District Rule 2410]

21. Source testing to quantify N2O emissions (lb-N2O/ton of HNO3 produced) shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081, 2201, and 2410]

22. Source testing shall be conducted using EPA method 320 or other source test methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

23. {33} Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

24. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

25. The nitric acid plant shall comply with the requirements of 40 CFR Part 60, Subpart Ga. [40 CFR 60 Subpart Ga]

26. The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60. [District Rules 2201, 1080, and 40 CFR 60 Subpart Ga]

27. The permittee shall install, calibrate, maintain, and operate a stack gas flow rate monitoring system. [40 CFR 60 Subpart Ga]

28. The permittee shall determine hourly NOx emissions rate and calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). [40 CFR 60 Subpart Ga]

29. The CEMS shall be in continuous operation during all operating periods including unit startup and shutdown, and malfunction. [District Rule 1080 and 40 CFR 60 Subpart Ga]

30. The permittee must use cylinder gas audits to fulfill the quarterly auditing requirement. [40 CFR 60 Subpart Ga]

31. For the NOx concentration CEMS, the permittee must use a span value, as defined in Performance Specification 2, Section 3.11, of Appendix B of this part, of 500 ppmv (as NO2). If the NOx concentrations emitted is higher than 600 ppmv (e.g., during startup or shutdown periods), the permittee must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NOx emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods. [40 CFR 60 Subpart Ga]

32. The permittee shall perform a relative accuracy test audit (RATA) for the NOx CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080 and 40 CFR 60 Subpart Ga]

33. The permittee must operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of §60.13 and Performance Specification 6 of Appendix B of part 60 and the specifications of Section 60.73a (Subpart Ga). [District Rule 1080 and 40 CFR 60 Subpart Ga]

34. The permittee must conduct an initial performance test to demonstrate compliance with the NOx emissions limit under §60.72a(a) beginning in the calendar month following initial certification of the NOx and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NOx average concentration, mass flow rate recorded with the certified NOx concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. The permittee must assure that the CERMS meets all of the data quality assurance requirements as per §60.13 and Appendix F, Procedure 1, of this part and you must use the data from the continuous emissions rate monitoring system (CERMS) for this compliance determination. [District Rule 1080 and 40 CFR 60 Subpart Ga]

35. The permittee shall calculate the 24-hour day rolling arithmetic average emission rate in units of the applicable emissions standard (lb-NOx/ton 100 percent acid produced) at the end of each operating day using all the quality assured hourly average CEMS data for the previous 24 operating hours according to the procedures specified in Section 60.75a. [District Rule 2201 and 40 CFR 60 Subpart Ga]

36. The permittee shall maintain records of the following information for each operating day period: (1) hours of operation; (2) production rate of nitric acid, expressed as 100 percent nitric acid; (3) 24-hour average NOx emissions rate values. [District Rule 2201 and 40 CFR Subpart Ga]

37. The permittee shall maintain records of the following time periods: (1) times when the equipment is not in compliance with the emissions standards; (2) times when the pollutant concentration exceeded full span of the NOx monitoring equipment; (3) times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [40 CFR 60 Subpart Ga]

38. The permittee shall maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications. For each malfunction, the permittee shall maintain records of the following information: (1) records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment; (2) records of actions taken during periods of malfunction to minimize emissions in accordance with section 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [District Rule 1080 and 40 CFR 60 Subpart Ga]

39. The permittee to submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the Administrator at the appropriate address as shown in 40 CFR 60.4. The permittee shall report to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard: (1) Time period; (2) NOx emission rates (lb/ton of acid produced); (3) Reasons for noncompliance with the emissions standard; and (4) Description of corrective actions taken. The permittee shall also report the following whenever they occur: (1) Times when the pollutant concentration exceeded full span of the NOx pollutant monitoring equipment; and (2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [District Rule 1080 and 40 CFR 60 Subpart Ga]

40. The permittee shall report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications. [40 CFR 60 Subpart Ga]

41. Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, the permittee must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/SSL/cdx/EPA_Home.asp) in the format specified in 40 CFR 60 Subpart Ga, Section 60.77a. [40 CFR 60 Subpart Ga]

42. If a malfunction occurred during the reporting period, the permittee must submit a report that contains the following: (1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded; (2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with §60.11(d), including actions taken to correct a malfunction. [40 CFR 60 Subpart Ga]

43. Source testing to measure the NOx and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after the conclusion of the commissioning period and at least once every twelve months thereafter. [District Rules 1081]

44. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia - EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081]

45. NH3 emissions for source test purposes shall be determined using BAAQMD method ST-1B. [District Rule 1081]

46. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

47. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

48. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

49. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

50. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

51. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

52. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

53. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

54. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants,

vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

55. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

56. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-36-0

AMMONIUM NITRATE UNIT THAT PRODUCES AMMONIUM NITRATE, CONSISTING OF: NEUTRALIZER WITH INTEGRAL SCRUBBER TO CONTROL AMMONIA; PROCESS CONDENSATE TANK WITH VENT SCRUBBER TO CONTROL PARTICULATE MATTER EMISSIONS; AMMONIUM NITRATE COOLER, AND PROCESS PUMP(S)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. The permittee shall calibrate, maintain and operate the wet scrubber according the manufacturer's specifications and recommendations. The permittee shall keep records on-site for a period of five years of the calibration and maintenance activities. [District Rule 2201]

9. PM10 emissions from scrubber vent shall not exceed 0.20 lb-PM10/hr. [District Rule 2201]

10. PM10 emission from scrubber vent shall not exceed 0.0075 lb-PM10 per ton of ammonium nitrate produced (based on an annual average). [District Rule 2201]

11. Production of ammonium nitrate shall not exceed 213,378 tons during any consecutive 12-month period. [District Rule 2201]

12. The permittee shall keep records of daily ammonium nitrate production. These records shall contain each month's total and a rolling total for the previous 12 months. [District Rule 2201]

13. Source testing to quantify PM10 emissions (lb-PM10/hr and lb-PM10/ton of ammonium nitrate produced) from scrubber vent shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081 and 2201]

14. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

15. The following test methods shall be used PM10: EPA method 5 (front half and back half). Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 2201]

16. {33} Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

17. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

18. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

19. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

20. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more

than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

21. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

22. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

23. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

24. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

25. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

26. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

27. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

28. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount,

and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-37-0

UREA STORAGE AND HANDLING OPERATION CONSISTING OF FOUR 20,000-TON STORAGE CAPACITY ENCLOSED UREA STORAGE DOMES EACH WITH ONE UREA TRANSFER TOWER, WITH EACH TRANSFER TOWER SERVED BY ONE DUST COLLECTOR; ENCLOSED UREA RECLAIM BUILDING WITH RECLAIM HOPPERS AND GRIZZLIES; ENCLOSED, TUBULAR RECLAIM CONVEYOR (THAT TRANSFERS MATERIAL TO UREA TRANSFER TOWER #5); UREA TRANSFER TOWER #5 SERVED BY DUST COLLECTOR; ENCLOSED, TUBULAR LOADOUT FEED CONVEYOR (THAT TRANSFERS MATERIAL TO LOADOUT BUILDING); UREA LOADOUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH RAIL/TRUCK LOADOUT CONVEYOR, ONE TRUCK AND ONE TRAIN LOADOUT WEIGH SYSTEM, AND ONE TRUCK AND ONE TRAIN LOADING SPOUT AND VENT SYSTEM

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Operation shall include the following dust collectors serving the following operations: urea bucket elevator to conveyor, five urea transfer towers, urea loading building vent. [District Rule 2201]

7. All conveyors shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

8. All transfer towers, conveyors, urea domes, and urea handling buildings shall be dust-tight (to prevent visible emissions in excess of 5% opacity) and shall vent only to dust collectors. [District Rule 2201]

9. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5% opacity) provisions to return collected material to process equipment. [District Rule 2201]

10. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

11. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

12. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

13. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

14. Permittee shall maintain daily records of the hours of operation of material unloading at the enclosed truck receiving hoppers and records shall be made available for District inspection upon request. [District Rule 2201]

15. Airflow for the following dust collector(s) shall not exceed any of the following name plate capacities: urea transfer tower 1: 1,500 cfm; urea transfer tower 2: 1,500 cfm; urea transfer tower 3: 1,500 cfm; urea transfer tower 4: 1,500 cfm; urea transfer tower 5: 1,500 cfm; urea loading building: 20,000 cfm. [District Rule 2201]

16. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

17. PM10 emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 0.3 lb/day; urea transfer tower 2: 0.3 lb/day; urea transfer tower 3: 0.3 lb/day; urea transfer tower 4: 0.3 lb/day; urea transfer tower 5: 0.3 lb/day; urea loading building: 4.1 lb/day. [District Rule 2201]

18. PM10 emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 113 lb/yr; urea transfer tower 2: 28 lb/yr; urea transfer tower 3: 56 lb/yr; urea transfer tower 4: 28 lb/yr; urea transfer tower 5: 27 lb/yr; urea loading building baghouse: 357 lb/yr. [District Rule 2201]

19. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

20. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

21. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

22. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

23. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 1081]

24. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

25. Source testing to determine opacity shall be conducted using EPA method 9. [District Rule 1081]

26. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 1081]

27. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emission rate limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 1081]

28. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 1081]

29. Permittee shall maintain a logbook (written or electronic) with the records specified in this document on-site and make it available upon request. [District Rule 1081]

30. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

31. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

32. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

33. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

34. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

35. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

36. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

37. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain

continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

38. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

39. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

40. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-38-0

2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #1 (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

9. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

10. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

11. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

14. Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

15. The engine EPA Tier rating shall be the highest applicable Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

16. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 4702 and 2410, and 17 CCR 93115]

17. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

18. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

19. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

20. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

21. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

22. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

23. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

24. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

25. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

26. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

27. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

28. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

29. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity

and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

30. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

31. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

32. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

33. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-39-0

2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #2 (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

9. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

10. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

11. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

14. Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

15. The engine EPA Tier rating shall be the highest applicable Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

16. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 4702 and 2410, and 17 CCR 93115]

17. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

18. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

19. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

20. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

21. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

22. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

23. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

24. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

25. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

26. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

27. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

28. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

29. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity

and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

30. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

31. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

32. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

33. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

S-7616-40-0

556 BHP CUMMINS MODEL CFP-15E-F40 INTERIM TIER 4 (OR THE HIGHEST TIER RATING IN EFFECT ON THE DATE OF ACQUISITION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A FIREWATER PUMP (OR EQUIVALENT)

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,914 lb, 2nd quarter: 39,914 lb, 3rd quarter: 39,914 lb, and 4th quarter: 39,914 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

4. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, and/or S-3557-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

9. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

10. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

11. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

12. Emissions from this IC engine shall not exceed any of the following limits: 1.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

13. Emissions from this IC engine shall not exceed 0.015 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

14. The engine EPA Tier rating shall be the highest applicable Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

15. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems". Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 2410, and 17 CCR 93115]

16. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

17. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

18. The permittee shall obtain written District approval for the use of any alternate equivalent equipment not specifically approved by this Determination of Compliance. Approval of the alternate equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

19. The permittee's request for approval of alternate equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

20. Alternate equivalent equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

21. No emission factor and no emission shall be greater for the alternate equivalent equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

22. The air quality modeled impacts of the proposed alternate equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

23. {3433} Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

24. {3434} An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

25. {3435} An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

26. {3436} Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

27. {3437} Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

28. {3438} Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

29. {3439} Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

30. {3440} On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

31. {3441} Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

32. {3442} Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

APPENDIX B
BACT Guidelines

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.4.8*

Last Update 9/1/2006

Refinery Flare

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.		
NOx	Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.	Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MM Btu. Flare shall be equipped with a flare gas recovery system for non-emergency releases.	
PM10	Engineered flare designed for and operated without visible emissions, except as allowed by 40CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.		
SOx	Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and purge gas shall be natural gas, treated refinery gas or LPG.		

VOC	Engineered flare designed with a VOC destruction efficiency of ≥ 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.	Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of ≥ 98.5%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.2.1*

Last Update 3/25/1995

Petroleum Coke Handling - Receiving, Storage, and Loadout = or > 1,000 tons coke per day

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10	Adequate moisture content of coke received, and loaded out, to prevent visible emissions in excess of 5% opacity. Water and surfactant applied to storage piles.		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.4.1*

Last Update 10/20/1992

Dry Material Storage and Conveying Operation, 100 tons/day

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10	Storage, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.4.2*

Last Update 9/29/1992

Wet Material Storage and Conveying Operation, 200 tons/day

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10	Enclosed storage with sufficient moisture so visible emissions are less than 5% opacity from any single emission point		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.4.3*

Last Update 4/2/2012

Dry Material Handling Operation - Mixing, Blending, Milling, or Storage

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10	Mixer, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse, or equivalent (99% or greater control efficiency)		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 4.12.1*

Last Update 11/26/2006

Chemical Plants - Valves & Connectors

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to District Rule 4455		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 4.12.2*

Last Update 11/27/2006

Chemical Plants Pump and Compressor Seals

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Leak defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 7.2.6*

Last Update 11/1/2000

Petroleum Refineries and Chemical Plants - Diesel Fuel Processing, Sulfur Recovery Plant, = or > 20 tons Sulfur/day

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
SOx	Sulfur Recovery Unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown.	Sulfur recovery unit with two tail gas treating units in parallel (one as standby) to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown.	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.1*

Last Update 7/10/2009

Emergency Diesel IC engine

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Latest EPA Tier Certification level for applicable horsepower range		
NOX	Latest EPA Tier Certification level for applicable horsepower range		
PM10	0.15 g/hp-hr or the Latest EPA Tier Certification level for applicable horsepower range, whichever is more stringent. (ATCM)		
SOX	Very low sulfur diesel fuel (15 ppmw sulfur or less)		
VOC	Latest EPA Tier Certification level for applicable horsepower range		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.Y.Z

Emission Unit: Combustion Turbine Generator – Fired on Hydrogen-Rich Syngas and Natural Gas, Uniform and Variable Load, With or Without Heat Recovery

Equipment Rating: Power Output > 50 MW

Industry Type: Integrated Gasification Combined Cycle Power Plant

Last Update: November xx, 2010

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx		1. Selective catalytic reduction designed to achieve 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd-NOx @ 15% O_2 (1-hour average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown. 2. Selective catalytic reduction designed to achieve 3.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown. 3. Selective catalytic reduction that achieves 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.	
VOC		1. Oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively; and is designed to achieve 1.5 ppmvd-VOC @ 15% O2 but does not exceed 2.0 ppmvd-VOC when firing on fuel containing natural gas. 2. Oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively; and 2.0-VOC ppmvd @ 15% O2 when firing on fuel containing natural gas.	

CO		1. Oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively; and is designed to achieve 4.0 ppmvd @ 15% O2 but does not exceed 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas. 2. Oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively and 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas.	
PM10	Air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, non-PUC regulated gas with no more than 0.75 grains-S/100 dscf, or 0.0003 lb-SOx/MMBtu when firing on H2-rich fuel exclusively.		
SOx	PUC-regulated natural gas or non-PUC regulated natural with no more than 0.75 grains-S/100 dscf, or 0.0003 lb-SOx/MMBtu when firing on H2-rich fuel exclusively		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

X

4th Quarter 2010

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.Y.Z

Emission Unit: Coal/Coke Gasification CO2 Recovery System

Industry Type: Integrated Gasification Combined Cycle Power Plant

Equipment Rating: All

Last Update: December xx, 2009

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
CO		Capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation); venting allowed when transportation system is unavailable due to upset condition up to 504 hr per rolling 12-month period.	
VOC		Capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation); venting allowed when transportation system is unavailable due to upset condition up to 504 hr per rolling 12-month period.	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

X

4th Quarter 2009

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.Y.Z

Emission Unit: Nitric acid unit
Equipment Rating: up to 501 tons of nitric acid produced per day (expressed as 100 percent nitric acid)

Industry Type: Fertilizer manufacturing
Last Update: January xx, 2013

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx	Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.50 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis	Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline X.Y.Z

Emission Unit: Ammonium nitrate unit

Industry Type: Fertilizer manufacturing

Equipment Rating: up to 636 tons per day of ammonium nitrate solution produced

Last Update: January xx, 2013

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
PM10		Wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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APPENDIX C
Top Down BACT Analyses

Top Down BACT Analysis for the Combustion Turbine Generator (S-7616-26)

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The new SJVUAPCD BACT Clearinghouse guideline (number to be determined later), identifies technologically feasible BACT for NO_X emissions from combustion turbine generators that are fired on hydrogen-rich syngas and natural gas as follows:

1) Selective catalytic reduction designed to achieve 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd-NOx @ 15% O_2 (1-hour average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.
2) Selective catalytic reduction designed to achieve 3.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.
3) Selective catalytic reduction that achieves 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.

No other control alternatives are identified as achieved in practice or alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

All the options identified in Step 1 are technologically feasible when firing on hydrogen-rich fuel, however when firing on natural gas, only the 4.0 ppmvd-NOx is technologically feasible as explained below.

The MHI 501 GAC® is a new turbine model designed to optimally fire on hydrogen-rich fuel, and it will fire on natural gas as a backup fuel only on a very limited basis. The backup natural gas firing will occur only during startup and shutdown of the combustion turbine and during periods of unplanned equipment outages up to 336 hours per year—periods when hydrogen gas is not available because the hydrogen-producing equipment is out of service. Conditions will limit the firing on natural gas to CTG startups (with firing on natural gas not to exceed 5 total hours per calendar year), CTG shutdowns (with firing on natural gas not to exceed 10 hours per calendar year), or during periods of unplanned equipment outages (with firing on natural gas not to exceed 336 hours per calendar year).

The fact that the turbine will fire primarily on hydrogen-rich fuel requires that the turbine be equipped with a diffusion-type combustor, as opposed to dry-low NOx (DLN) combustor technology, which is typically installed in modern combined-cycle units using natural gas fuel. With a diffusion-type combustor, NOx emissions will be controlled with diluent injection of nitrogen and a selective catalytic reduction (SCR) system.

Available DLN combustor technologies are designed for natural gas (methane-based) fuels, and this type of technology is not technically practical for syngas (hydrogen/CO-

based) fuels used by an IGCC combustion turbine due to the potential for explosion hazard in the combustion section due primarily to the high hydrogen content of the syngas. No manufacturer makes DLN combustions that can be used for a combustion turbine fueled by petroleum coke or coal-derived syngas. Research is ongoing to develop DLN for syngas-fueled combustion turbines; however, such combustor technology is not a technically feasible control option for this unit.

Post-combustion reduction of NOx from the flue gas will be achieved with selective catalytic reduction (SCR). The SCR process involves the injection of ammonia (NH3) into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NOx and NH3 to nitrogen and water. SCR will be used when firing hydrogen-rich fuel or natural gas.

The applicant has provided vendor guarantees that the SCR system reduces NOx emissions from the HRSG stack gases by up to 92 percent when firing hydrogen-rich fuel, and up to 94 percent when firing natural gas. The maximum NOx reductions that SCRs can typically achieve are 90 to 95 percent.[43] HECA will optimize the SCR system to achieve NOx reductions of this magnitude.

[44] Without the SCR, the MHI turbine can achieve exhaust emission levels of [redacted] (at 15 percent oxygen) NOx over a 3-hour average (excluding start-up, shut-down and upset periods) when firing 100 percent hydrogen-rich fuel with diluent injection. For natural gas combustion, emission levels of [redacted] (at 15 percent oxygen) NOx from the turbine exhaust are achieved with diluent injection. The applicant requests operation of the combined-cycle unit on natural gas fuel for a limited period of up to 2 weeks per year when the gasifier is unavailable, and during start up and shut down. The higher emission rate from the combustion of natural gas is caused by the difference in combustion characteristics of natural gas compared to the hydrogen-rich fuel in the diffusion burners.

Since the highest guaranteed control level available to the permittee for which they can secure for natural gas firing is [redacted] and the highest quoted control in practice is no better than [redacted], the emission level of [redacted] can be feasibly controlled to a level as low as [redacted] ppmvd-NOx. Therefore, for the backup natural gas firing, the lower 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd-NOx @ 15% O_2 (1-hour average) and the 3.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) are deemed to be not technologically feasible.

c. Step 3 - Rank remaining options by control effectiveness

1) Selective catalytic reduction designed to achieve 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd-NOx @ 15% O_2 (1-hour average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.

[43] This guarantee is better than the NOx control specified in EPA's AP-42 Section 3.1 (Stationary Gas Turbines),which states that the NOx removal efficiency of an SCR system in good working order is typically from 65 to 90 percent.

[44] The removed sections in this page contain information describing the uncontrolled emissions for the combustion turbine generator that has been designated confidential information per the applicant's request, and such information will be kept separate from public record.

2) Selective catalytic reduction designed to achieve 3.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), but does not exceed 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.
3) Selective catalytic reduction that achieves 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown.

Note: As explained in Step 2 above, the three options identified above are technologically feasible when firing on hydrogen-rich fuel. However, for natural gas firing the two most-effective options were deemed to be not technologically feasible in Step 2.

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked control option that had been deemed technologically feasible for each fuel source. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NO_X emissions from this combustion turbine generator is the use of selective catalytic reduction (SCR) that achieves 2.5 ppmvd-NOx @ 15% O_2 (1-hour average), except during startup/shutdown when firing on hydrogen-rich fuel. When firing on the backup natural gas, BACT is the use of SCR that achieves 4.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average), except during startup/shutdown. The applicant proposes the options identified as BACT. Therefore, BACT for NO_X emissions is satisfied.

2. BACT Analysis for SOx Emissions:

a. Step 1 - Identify all control technologies

The new SJVUAPCD BACT Clearinghouse guideline (number to be determined later), identifies achieved in practice BACT for SO_X emissions from combustion turbine generators that are fired on hydrogen-rich syngas and natural gas as follows:

1) PUC-regulated natural gas or non-PUC regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for SO_X emissions from this combustion turbine generator is PUC-regulated natural gas or non-PUC regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel. The applicant has proposed to install a combustion turbine generator that will be fired on PUC-regulated natural gas with no more than 0.75 grains-S/100 dscf, or hydrogen-rich fuel with emissions no more than 0.003 lb-SOx/MMBtu; therefore BACT for SO_X emissions is satisfied.

3. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The new SJVUAPCD BACT Clearinghouse guideline (number to be determined later), identifies achieved in practice BACT for PM10 emissions from combustion turbine generators that are fired on hydrogen-rich syngas and natural gas as follows:

1) Air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, non-PUC regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel exclusively

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM10 emissions from this combustion turbine generator is air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, non-PUC regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel exclusively. The applicant has proposed to install a combustion turbine generator with an air inlet cooler/filter, lube oil vent coalescer (or equal), and PUC-regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SOx/MMBtu when firing on hydrogen-rich fuel exclusively; therefore BACT for PM10 emissions is satisfied.

4. BACT Analysis for CO Emissions:

a. Step 1 - Identify all control technologies

The new SJVUAPCD BACT Clearinghouse guideline (number to be determined later), identifies technologically feasible BACT for CO emissions from combustion turbine generators that are fired on hydrogen-rich syngas and natural gas as follows:

1) Oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively; and is designed to achieve 4.0 ppmvd @ 15% O2 but does not exceed 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas.
2) Oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively and 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas.

No other control alternatives are identified as achieved in practice or alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

When firing on the primary fuel, hydrogen rich-fuel, the options identified in Step 1 are technologically feasible. However, when firing on natural gas, the lower 4.0 ppmvd-CO has not been proven to be technologically feasible as explained below.

The MHI 501 GAC® is a new turbine model designed to optimally use hydrogen-rich fuel, and natural gas as a backup fuel. The backup natural gas firing will occur only during startup and shutdown of the combustion turbine and during periods of unplanned equipment outages (up to 336 hours per year).

The permittee requests to fire the turbine/HRSG on natural gas for a limited period of time up to 336 hours per year when the gasifier is unavailable, and during startup and shutdown. The higher emission rate from combustion on natural gas is caused by the difference in characteristics of natural gas compared to the hydrogen-rich fuel in the diffusion burners. As is explained in the BACT evaluation of NOx emissions above, dry-low NOx (DLN) technology is not technologically feasible for the primary fuel, hydrogen-rich fuel. Thus it is also not feasible for the limited use of the natural gas backup fuel. As a result, highest-control option identified in Step 1 above is not proven to be technologically feasible. Therefore, this option is identified as infeasible only for the backup fuel, natural gas.

c. Step 3 - Rank remaining options by control effectiveness

1) Oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively; and 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas.

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for CO emissions from the proposed combustion turbine generator is the use of oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively and that achieves 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas. The applicant has proposed to install a combustion turbine generator equipped with an oxidation catalyst that achieves 3.0 ppmvd-CO @ 15% O2 when firing on hydrogen-rich fuel exclusively and that achieves 5.0 ppmvd @ 15% O2 when firing on fuel containing natural gas, except during startup/shutdown; therefore BACT for CO emissions is satisfied.

5. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The new SJVUAPCD BACT Clearinghouse guideline (number to be determined later), identifies technologically feasible BACT for VOC emissions from combustion turbine generators that are fired on hydrogen-rich syngas and natural gas as follows:

1) Oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively; and is designed to achieve 1.5 ppmvd-VOC @ 15% O2 but does not exceed 2.0 ppmvd-VOC when firing on fuel containing natural gas.
2) Oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively; and 2.0-VOC ppmvd @ 15% O2 when firing on fuel containing natural gas.

No other control alternatives are identified as achieved in practice or alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

When firing on the primary fuel, hydrogen rich-fuel, the options identified in Step 1 are technologically feasible. However, when firing on natural gas, the lower 1.5 ppmvd-VOC option has not been proven to be technologically feasible as explained below.

The MHI 501 GAC® is a new turbine model designed to optimally use hydrogen-rich fuel, and natural gas as a backup fuel. The backup natural gas firing will occur only during startup and shutdown of the combustion turbine and during periods of unplanned equipment outages (up to 336 hours per year).

The permittee requests to fire the turbine/HRSG on natural gas for a limited period of time up to 336 hours per year when the gasifier is unavailable, and during startup and shutdown. The higher emission rate from combustion on natural gas is caused by the difference in characteristics of natural gas compared to the hydrogen-rich fuel in the diffusion burners. As is explained in the BACT evaluation of NOx emissions above, dry-low NOx (DLN) technology is not technologically feasible for the primary fuel, hydrogen-rich fuel. Thus it is also not feasible for the limited use of the natural gas backup fuel. As a result, highest-control option identified in Step 1 above is not proven to be technologically feasible. Therefore, this option is identified as infeasible only for the backup fuel, natural gas.

c. Step 3 - Rank remaining options by control effectiveness

1) Oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively and 2.0-VOC ppmvd @ 15% O2 when firing on fuel containing natural gas.

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for VOC emissions from the proposed combustion turbine generator is the use of oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively and that achieves 2.0 ppmvd-VOC @ 15% O2 when firing on fuel containing natural gas. The applicant has proposed to install a combustion turbine generator equipped with an oxidation catalyst that achieves 1.0 ppmvd-VOC @ 15% O2 when firing on hydrogen-rich fuel exclusively and that achieves 2.0 ppmvd-VOC @ 15% O2 when firing on fuel containing natural gas, except during startup/shutdown; therefore BACT for VOC emissions is satisfied.

Top Down BACT Analysis for the PM10 emissions from:

- **Rail Unloading and Transfer System (S-7616-17)**
- **Truck Unloading and Transfer System (S-7616-18)**
- **Feedstock Grinding/Crushing and Drying System (S-7616-20)**

1. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The project consists of the following operations, which will handle coal and petroleum coke, that trigger BACT for PM10 emissions:

- Rail unloading vent (emission point #17 of the Rail Unloading and Transfer System, S-7616-17)
- Truck unloading vent (emission point #20 of the Truck Unloading and Transfer System, S-7616-18)
- Feedstock bunkers vent and feedstock crusher vent (emission points #21 and #18 of the Feedstock Grinding/Crushing and Drying System, S-7616-20)

The applicable BACT requirements for the proposed operations are covered by the following BACT guidelines:

- SJVUAPCD BACT Clearinghouse guideline 8.2.1 lists BACT requirements for Petroleum Coke Handling – Receiving, Storage, and Loadout.

- SJVUAPCD BACT Clearinghouse guideline 8.4.1 lists BACT requirements for Dry Material Storage and Conveying Operation.

- SJVUAPCD BACT Clearinghouse guideline 8.4.3 lists BACT requirements for Dry Material Handling – Mixing, Blending, Milling, or Storage.

These guidelines identify achieved in practice BACT for PM10 emissions that apply to the operation as follows:

Petroleum coke handling – receiving, storage, and loadout (Guideline 8.2.1):

1) Adequate moisture content of coke received, and loaded out, to prevent visible emissions in excess of 5% opacity. Water and surfactant applied to storage piles.

Dry material storage and conveying operation (Guideline 8.4.1):

1) Storage, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse

Dry material handling – mixing, blending, milling, or storage (Guideline 8.4.3):

1) Mixer, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the most effective control option identified above for each of the process areas.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to each of the process areas. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT requirements for PM10 emissions from the rail unloading vent, the truck unloading vent, the feedstock bunkers vent, and the feedstock crusher vent are the following: storage silos, mixers, augers, elevators, conveyors shall be fully enclosed and vented to a fabric filter baghouse(s); the petroleum coke shall contain adequate moisture to prevent visible emissions in excess of 5% opacity. The applicant has proposed that the dry material storage silos, crusher, augers, elevators, and conveyors all be enclosed and vented to fabric filter baghouse, and the petroleum coke will be required to contain adequate moisture content to prevent visible emissions in excess of 5% opacity. Therefore, BACT for PM10 emissions is satisfied.

Top Down BACT Analysis for the PM10 emissions from:

- **Gasification Solids Material Handling System (S-7616-22)**
- **Urea Storage and Handling Operation (S-7616-37)**

1. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The project consists of the following material handling operations that trigger BACT for PM10 emissions:

- Gasification solids load-out system (emission point #29 of the Gasification Solids Handling System, S-7616-22)
- Urea loading vent (emission point # 23 of the Urea Storage and Handling Operation, S-7616-37)

The applicable BACT requirements for the proposed operations are covered by the following BACT guidelines:

SJVUAPCD BACT Clearinghouse guideline 8.4.1 lists BACT requirements for Dry Material Storage and Conveying Operation.

SJVUAPCD BACT Clearinghouse guideline 8.4.2 lists BACT requirements for Wet Material Storage and Conveying Operation.

SJVUAPCD BACT Clearinghouse guideline 8.4.3 lists BACT requirements for Dry Material Handling – Mixing, Blending, Milling, or Storage.

These guidelines identify achieved in practice BACT for PM10 emissions that apply to the operation as follows:

Dry material storage and conveying operation (Guideline 8.4.1):

1) Storage, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse

Wet material storage and conveying operation (Guideline 8.4.2):

1) Enclosed storage with sufficient moisture so visible emissions are less than 5% opacity from any single emission point

Dry material handling – mixing, blending, milling, or storage (Guideline 8.4.3):

1) Mixer, augers, elevators, conveyors all enclosed and vented to a fabric filter baghouse

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the most effective control option identified above for each of the process areas.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to each of the process areas. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT requirements for PM10 emissions from the gasification solids load-out system (of the gasification solids handling system, S-7616-22) and the urea loading vent (of the urea storage and handling operation, S-7616-37) are the following: storage, mixers, augers, elevators, conveyors shall be fully enclosed and vented to fabric filter baghouse(s); the stored wet material shall contain adequate moisture to prevent emissions in excess of 5% opacity. The applicant has proposed that all storage, mixers, augers, elevators, conveyors be enclosed and vented to fabric filter baghouse(s), and the wet material storage area will be required to contain adequate moisture content to prevent visible emissions in excess of 5% opacity. Therefore, BACT for PM10 emissions is satisfied.

Top Down BACT Analysis for the Fugitive Emissions Associated with: Gasification System (S-7616-21) and Sulfur Recovery Unit (S-7616-23)

1. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 4.12.1 applies to chemical plant valves and connectors and guideline 4.12.2 applies to chemical plant pump and compressor seals. Guideline 4.12.1 identifies achieved the following as practice BACT for VOC emissions for valves and connectors:

1) Leak defined as a reading of methane in excess of 100 ppmv above background when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455

Guideline 4.12.2 identifies the following as achieved in practice BACT for VOC emissions for pump and compressor seals:

1) Leak defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455

No other control alternatives are identified as technologically feasible or alternate basic equipment for this class and category of source by these guidelines.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. Leak defined as a reading of methane in excess of 500 ppmv above background for pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for VOC emissions a leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors and in excess of 500 ppmv above background for pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. The applicant has proposed to these control measures; therefore BACT for VOC emissions is satisfied.

Top Down BACT Analysis for the Sulfur Recovery Unit (S-7616-23)

1. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 7.2.6, identifies achieved in practice BACT for SOx emissions from sulfur recovery plants that process 20 tons/day of sulfur or more as follows:

1) Sulfur recovery unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown.

The guideline also identified the following as technologically feasible BACT:

In addition, the guideline identifies technologically feasible BACT for SOx emissions as follows:

2) Sulfur recovery unit with two tail gas treating units in parallel (one as standby) to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown

No other control alternatives are identified as alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1a) Sulfur recovery unit with two tail gas treating units in parallel (one as standby) to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown

1b) Sulfur recovery unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The difference between the two options identified in Step 3 is the fact that the first control option calls for an second tail gas treating unit (to serve as standby) to treat the gas. Under normal operating conditions, the gas stream from the sulfur recovery unit will be treated in the tail gas treating unit then transported by pipeline to the CO2 vent system

(S-7616-25) for custody transfer point at Elk Hills Field for CO2 enhanced oil recovery (EOR) and sequestration. A tail gas thermal oxidizer, as required by both control options, will also be included as a control device to provide for safe and efficient destruction of the hydrogen sulfide in the vent gas during startups and shutdowns.

In this case, the addition of a backup tail gas treating unit will not achieve any additional control since there are typically no SRU emissions to atmosphere as the treated stream will be transported by pipeline for EOR and sequestration. Additionally, scheduled TGU maintenance shutdowns will be planned to coincide with process block shutdowns so there are no excess process emissions. In the event of any unscheduled TGU curtailment or operating problems, the SRU tail gas can be redirected into the CO2 product stream up to the limits contained in the CO2 product specifications for S-7616-25, and/or the process block can be curtailed or shutdown to accommodate maintenance necessary to restore the TGU operations.

With all these built in control measures, the inclusion of a second tail gas treating unit would not achieve any additional control. Therefore, the emission reduction due to a second tail gas treating unit will be zero, so this alternate control will automatically be cost ineffective, and it can be eliminated from consideration.

e. Step 5 - Select BACT

BACT for SOx emissions from the sulfur recovery plant is the use of a sulfur recovery unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator, except during startup and shutdown. The applicant has proposed to install a sulfur recovery unit with tail gas treating unit to treat gas to = or < 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator, except during startup and shutdown; therefore BACT for SOx emissions is satisfied.

Top Down BACT Analysis for the CO2 Recovery System (S-7616-24)

1. BACT Analysis for CO and VOC Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline that was approved for project S-1093741, identifies technologically feasible BACT for CO and VOC emissions from a coal/coke gasification CO2 recovery system as follows:

1) Capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation); venting allowed when transportation system is unavailable due to upset condition up to 504 hr (or its equivalent flowrate) per rolling 12-month period

No other control alternatives are identified as achieved in practice or as alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation); venting allowed when transportation system is unavailable due to upset condition up to 504 hr (or its equivalent flowrate) per rolling 12-month period

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for CO and VOC emissions from the CO2 recovery system is the capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation), with venting allowed when transportation system is unavailable due to upset condition up to 504 hr (or equivalent) per rolling 12-month period. The applicant has proposed the capture, compression, and transportation of the exhaust stream in a pipeline for injection (during normal operation), with venting up to 504 hr (or equivalent) per rolling 12-month period when the transportation system is unavailable due to upset conditions; therefore BACT for CO and VOC emissions is satisfied.

Top Down BACT Analysis for Natural Gas-Fired Auxiliary Boiler (S-7616-25)

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The District adopted District Rule 4320 on October 16, 2008. The NO_X emission limit requirements in District Rule 4320 are lower than the current BACT limits; therefore a project specific BACT analysis will be performed to determine BACT for this project. District Rule 4320 includes a compliance option that limits oilfield steam generators with heat input ratings greater than 20 MMBtu/hr to 7 ppm @ 3% O_2. This emission limit is Achieved in Practice control technology for the BACT analysis. District Rule 4320 also contains an enhanced schedule option that allows applicants additional time to meet the requirements of the rule. The enhanced schedule NO_X emission limit requirement is 5 ppmv @ 3% O_2. Since this is an enhanced option in the rule, it will be considered the Technologically Feasible control technology for the BACT analysis.

The SJVUAPCD BACT Clearinghouse Guideline 1.1.2 has been rescinded. Therefore a new BACT analysis is required. The following are possible control technologies:

1. 7 ppmvd @ 3% O2 - Achieved in Practice.
2. 5 ppmvd @ 3% O2 with SCR – Technologically Feasible

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 7 ppmvd @ 3% O2 - Achieved in Practice.
2. 5 ppmvd @ 3% O2 with SCR – Technologically Feasible

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the highest ranked technologically feasible option in the list in Step 3. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NO_X emissions from the proposed auxiliary boiler is controlling emissions to 5 ppmv-NOx @ 3% O_2. The applicant has proposed a boiler with emissions controlled to 5 ppmv-NOx @ 3% O_2 with the use of selective catalytic reduction; therefore BACT for NO_X emissions is satisfied.

2. BACT Analysis for VOC, SOx, CO, and PM_{10} Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.1.2 identifies achieved in practice and technologically feasible BACT for Steam Generator $\geq$ 20 MMBtu/hr, at an oil field as follows:

1. Natural gas fuel with LPG backup

b. Step 2 - Eliminate Technologically Infeasible Options

The above listed technology is technologically feasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

d. Step 4 - Cost Effectiveness Analysis

Only one control technology identified and this technology is achieved in practice, therefore, cost effectiveness analysis not necessary.

e. Step 5 - Select BACT for VOC, SOx, CO, and PM_{10}

BACT is the use of natural gas with LPG backup. The applicant has proposed the use of PUC-quality natural gas; therefore, BACT for VOC, SOx, CO, and PM_{10} emissions is satisfied.

Top Down BACT Analysis for the Cooling Towers (S-7616-27, -28, -29)

1. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 8.3.10, identifies technologically feasible BACT for PM10 emissions from cooling towers – induced draft, evaporative cooling as follows:

1) Cellular Type Drift Eliminator (Achieved in Practice)

In addition, air-cooled condensers were also analyzed.

2) Air-Cooled Condenser (Technologically Feasible)

No other control alternatives are identified as achieved in practice or alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Air-Cooled Condenser

2) Cooling Tower with Cellular Type Drift Eliminator

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis is required for technologically feasible control options that are not proposed. The applicant is proposing the installation of a cooling tower with a cellular-type drift eliminator instead of an air-cooled condenser. Therefore, a cost effective analysis is required for an air-cooled condenser.

Air-Cooled Condenser:

Assumptions:

In order to determine the cost effectiveness of an air-cooled condenser, the most favorable conditions for making it cost-effective will be assumed (e.g. that it controls all of the PM10 that a cooling tower with a cellular-type drift eliminator does not).

Calculations:

The annual potential emissions from each of the cooling towers S-7616-27, S-7616-28, and S-7616-29 using cellular-type drift eliminators are 30,438 lb-PM10/yr, 1,867 lb-PM10/yr, and 18,640 lb-PM10/yr, respectively, for a total of 50,945 lb-PM10/yr.

Therefore, assuming that an air-cooled condenser were to control all of the these emissions from the cooling towers, the maximum difference in emissions controlled would be 50,945 lb-PM10/yr

Maximum emission reductions: 50,945 lb-PM10/yr = 25.47 tons-PM10/yr

Cost Analysis:

According to HECA's Response to Sierra Club Data Request #127, the cost differential for an air-cooled condenser is approximately $20 million to $30 million more than a cooling tower equipped with cellular-type drift eliminators. Therefore, conservatively assuming an additional capital cost to replace the proposed cooling towers with an air-cooled condenser, the additional total annualized cost of can be calculated as follows:

Total Estimated Capital Cost: **$20,000,000**

Equivalent Annual Capital Cost (Capital Recovery)

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1}$$ where;

A = Equivalent Annual Control Equipment Capital Cost
P = Present value of the control equipment, including installation cost
i = interest rate (use 10%, or demonstrate why alternate is more representative of the specific operation).
n = equipment life (assume 10 years or demonstrate why alternate is more representative of the specific operation)

Where

P =$20,000,000
I =10%,
n= 10 years
A = $813,727

Total annualized cost = $3,254,908/yr

Cost effectiveness:

Cost effectiveness = Cost of control / Emission reduction
= ($3,254,908/yr) / (25.47 tons-PM10/yr)
= $127,794/tons-PM10 reduced

The cost of an air-cooled condenser is greater than the $11,400/ton-PM10 cost effectiveness threshold of the District BACT policy. Therefore the use of an air-cooled condenser is not cost effective and is not required as BACT.

The applicant proposes the remaining control for BACT, the use of cooling towers for equipped with cellular-type drift eliminators.

e. Step 5 - Select BACT

BACT for PM10 emissions from this cooling tower is cellular type drift eliminator. The applicant has proposed to install a cellular type drift eliminator with a drift rate of 0.0005%; therefore BACT for PM10 emissions is satisfied.

Top Down BACT Analysis for Flares (S-7616-30, -31, and -32):

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.4.8 identifies the following as achieved in practice BACT for NOx emissions from a refinery flare:

- Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

In addition, the guideline identifies the following as technologically feasible BACT for NOx emissions:

- Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MMBtu. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

No other control alternatives are identified as alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

The applicant has proposed the most effective control option identified above. Each of the proposed engineered flares will comply with 0.068 lb-NOx/MMBtu emission limit and will be equipped with an enclosed burner that is equipped with District-approved controls that will result in smokeless operation as described below. The flare systems will be designed, constructed, and commissioned by a qualified engineering firm with extensive experience with this type of equipment. The flare tips selected will likewise be engineered by qualified suppliers. Carbon present in relief gases sent to each of the three flares is expected to be almost all in the oxidized (CO, CO2) state rather than in a reduced (hydrocarbon) state. The lack of reduced carbon is expected to result in virtually no smoke formation over the expected range of flaring events. Therefore, the flare tip suppliers have indicated that no assist steam or air is necessary to achieve smokeless combustion, and this proposal is deemed as District-approved controls that are equivalent to a flare with air or steam assisted combustion or staged combustion. Normal operation of the gasification flare will include flaring during gasifier startup operations. No flaring (other than pilot gas combustion) is planned during normal operation.

The flares will also be equipped with a system of pressure relief valves/pressure control valves to prevent non-emergency releases of gases into the flare headers. These systems are determined to be as effective and appropriate means for reducing emissions as the flare gas recovery system for non-emergency releases as specified in the

applicable BACT determination. The configurations and measures are described in more detail below:

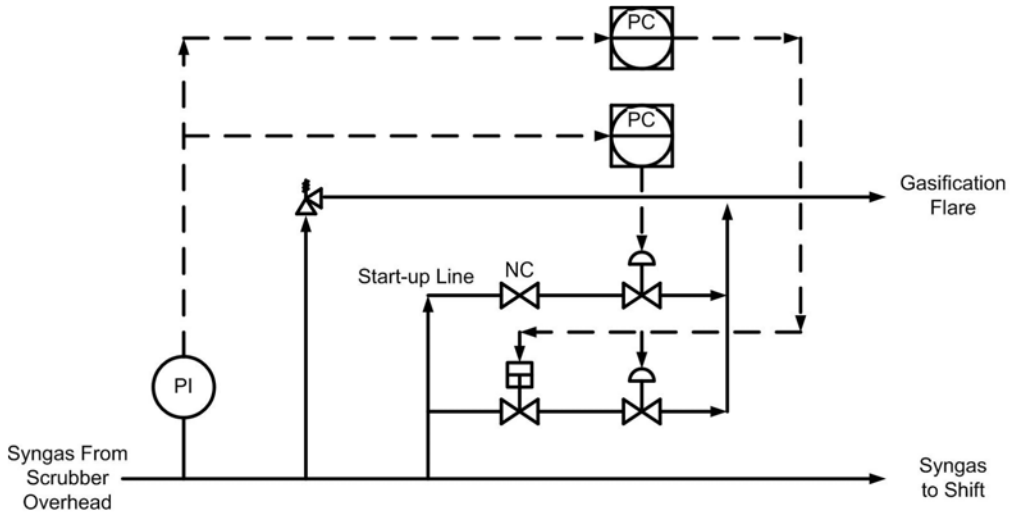
Gasification Flare (S-7616-30-0)

The gasification flare will be used to safely dispose of gas streams during gasifier startup, shutdown, and unplanned upset emergency events such as short-term emergency combustion turbine outages. The gasification flare will be the device to provide any necessary relief service to the gasifier, shift reactor discharge, and treated hydrogen rich gas from the Rectisol unit. Since the gasifier and shift reactor discharge process streams have some sulfur content during normal operations, the relief devices associated with these process streams include a pressure control valve arrangement that works to minimize flare emissions. Following is a discussion on how the relief valve/control valve configuration at these sources is operated to minimize emissions.

Following nitrogen purging the gasifier is warmed up using natural gas on a combustion burner. Following warm up, gasification of the natural gas is started by introducing oxygen. The syngas produced is essentially sulfur-free. The clean syngas is routed from the gasifier or the shift reactor discharge to the gasification flare through a startup line and pressure controller arrangement as shown in Figure 1. Following a successful startup, a tight shutoff valve is closed on the startup line at both the gasifier and shift reactor discharge to prevent leakage through the start-up pressure controller and a smaller parallel valve set that includes a control valve and a tight seal “chopper” valve is placed in service. The pressure controller/chopper valve configuration works to stop any non-emergency process leakage from the scrubber overhead relief valve into the flare system during normal operations.

Because it is a tight shutoff arrangement, any flow through the device is not expected except during an actual flaring event. The pressure controller/chopper valve arrangement can handle smaller flare events and provides additional assurance that the process pressure is maintained sufficiently below the relief valve set point. This greater difference in pressure afforded to the relief valve results in a tighter seal at the relief valve and lower likelihood that minor variations in operating pressure will cause a leak or lift. Reducing relief valve lifts also reduces the potential for any re-seating and leakage problems.

Figure 1 Syngas Relief Valve Configuration [45]



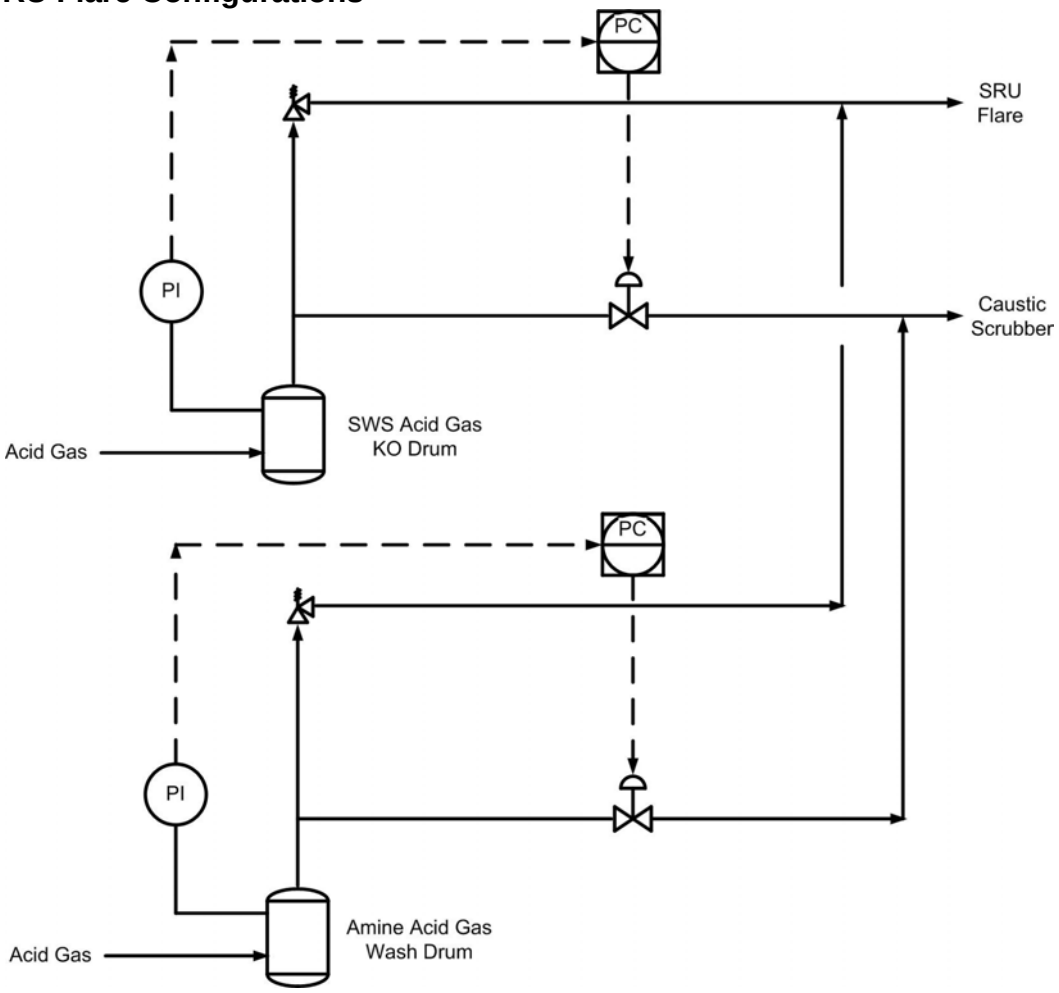
SRU Flare (S-7616-31-0):

The sulfur recovery unit (SRU) flare will be used to safely dispose of gas streams during startup and shutdown and unplanned upsets or emergency events. The SRU flare will be the device providing any necessary relief service to the acid gas system and the sour water stripper. During startups and shutdowns and most flaring events, the acid gas is routed to a caustic scrubber via a pressure controller (as shown in Figure 2) where the sulfur compounds are absorbed by the caustic solution. After scrubbing, the gas is routed to the elevated SRU flare stack via the SRU flare knockout drum. Fresh and spent caustic tanks and pumps are provided to allow delivery of fresh caustic and disposal of spent caustic. Since the pressure relief valve set point is set higher than the control valve set point, the relief valve will only be utilized during infrequent emergency events.

The pressure controller/caustic wash configuration also works to reduce any process leakage during normal operations that might cause the issuance of air contaminants. The pressure controller provides additional assurance that the process pressure is maintained sufficiently below the relief valve set point. This greater difference in pressure results in a tighter seal at the relief valve and lower likelihood that minor variations in operating pressure will cause a leak or lift. Eliminating non-emergency relief valve lifts reduces the potential for any re-seating and leakage problems.

[45] The shift reactor discharge shown is shown in the figure. Gasifier is similar.

Figure 2 SRU Flare Configurations



Rectisol Flare (S-7616-32-0)

The Rectisol flare will be used to safely dispose of low-temperature gas streams during unplanned upsets or emergency events. Cold reliefs and vents from the AGR unit and its associated refrigeration unit are collected in the Rectisol flare header. The Rectisol flare header is used only in emergencies or upsets and plant startup and shutdown and contains gases that can be below the freezing point of water. For this reason, the Rectisol flare header gases are segregated from the wet gases in the gasification flare header.

Therefore, the proposed systems are deemed an equivalent control to that provided by a flare gas recovery system for non-emergency releases.

c. Step 3 - Rank remaining options by control effectiveness

1) Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MMBtu. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

2) Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to the proposed flares. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NOx emissions for each flare is the use of an engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MMBtu. Flare shall be equipped with a flare gas recovery system, or equivalent, for non-emergency releases. As is explained in step 2, the applicant's proposal satisfies these requirements; therefore BACT for NOx emissions is satisfied for each of the flare.

2. BACT Analysis for CO Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.4.8, identifies achieved in practice BACT for CO emissions from a refinery flare as follows:

1) Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

No other control alternatives are identified as technologically feasible or alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to the flares. The flares will result in smokeless operation (as is explained in the BACT analysis for NOx emissions), which constitutes District-approved controls that

are equivalent to air or steam assisted combustion or staged combustion. The flares will also be equipped with a series of control valves and relief valves (as described in the BACT analysis for NOx emissions section) that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. These arrangements are deemed controls equivalent to a flare gas recovery system that minimizes non-emergency releases. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required since the applicant is proposing the most effective option.

e. Step 5 - Select BACT

BACT for CO emissions is the use of an engineered flare with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system, or equivalent, for non-emergency releases. As is explained in step 4, the applicant's proposal satisfies these BACT requirements; therefore BACT for CO emissions is satisfied.

3. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.4.8, identifies achieved in practice BACT for PM10 emissions from a refinery flare as follows:

1) Engineered flare designed for and operated without visible emissions, except as allowed by 40 CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

No other control alternatives are identified as technologically feasible or alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Engineered flare designed for and operated without visible emissions, except as allowed by 40 CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to the flares. The flares will result in smokeless operation (as is explained in the BACT analysis for NOx emissions), which constitutes District-approved controls that are equivalent to air or steam assisted combustion or staged combustion. The flares will also be equipped with a series of control valves and relief valves (as described in the BACT analysis for NOx emissions section) that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. These arrangements are deemed controls equivalent to a flare gas recovery system that minimizes non-emergency releases. Additionally, the flares will have a continuous pilot that will be fired on PUC-quality natural gas. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required since the applicant is proposing the most effective option.

e. Step 5 - Select BACT

BACT for PM10 emissions is the use of an engineered flare with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall

be equipped with a flare gas recovery system, or equivalent, for non-emergency releases. As is explained in step 4, the applicant's proposal satisfies these BACT requirements; therefore BACT for PM10 emissions is satisfied.

4. BACT Analysis for SOx Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.4.8, identifies achieved in practice BACT for SOx emissions from a refinery flare as follows:

1) Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and purge gas shall be natural gas, treated refinery gas or LPG.

No other control alternatives are identified as technologically feasible or alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and purge gas shall be natural gas, treated refinery gas or LPG.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable the flares. The flares will also be equipped with a series of control valves and relief valves (as described in the BACT analysis for NOx emissions section) that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. These arrangements are deemed controls equivalent to a flare gas recovery system that minimizes non-emergency releases. Additionally, the flares will have a continuous pilot that will be fired on PUC-quality natural gas. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required since the applicant is proposing the most effective option.

e. Step 5 - Select BACT

BACT for SOx emissions is the use of a flare with a flare gas recovery system, or equivalent, for non-emergency releases. Pilot and purge gas shall be natural gas. As is explained in step 4, the applicant's proposal satisfies these BACT requirements; therefore BACT for SOx emissions is satisfied.

5. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.4.8, identifies achieved in practice BACT for VOC emissions from a refinery flare as follows:

1) Engineered flare designed with a VOC destruction efficiency of ≥ 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

In addition, the guideline identifies technologically feasible BACT for NOx emissions as follows:

1) Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of ≥ 98.5%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

No other control alternatives are identified as alternate basic equipment for this class and category of source.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of ≥ 98.5%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

2) Engineered flare designed with a VOC destruction efficiency of ≥ 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the most effective control options identified in Step 3 that is applicable to the flares. The applicant proposes engineered flares designed with a VOC destruction efficiency of 99%. The flares will result in smokeless operation (as is explained in the BACT analysis for NOx emissions), which constitutes District-approved controls that are equivalent to air or steam assisted combustion or staged combustion. The flares will also be equipped with a series of control valves and relief valves (as described in the BACT analysis for NOx emissions section) that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. These arrangements are deemed controls equivalent to a flare gas recovery system that minimizes non-emergency releases. Additionally, the flares will have a continuous pilot that will be fired on PUC-quality natural gas. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required since the applicant is proposing the most effective option.

e. Step 5 - Select BACT

BACT for VOC emissions is the use of an enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of ≥ 98.5%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system, or equivalent, for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG. As is explained in step 4, the applicant's proposal satisfies these BACT requirements; therefore BACT for VOC emissions is satisfied.

Top Down BACT Analysis for a 56 MMBtu/hr Natural Gas-Fired Ammonia Synthesis Startup Heater (S-7616-33)

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The District adopted District Rule 4320 (Advanced Emissions Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) on October 16, 2008. The NO_X emission limit requirements in District Rule 4320 are lower than the limits in formerly-applicable BACT Guideline 1.1.2 (Boiler: > 20 MMBtu/hr, natural gas fired, base-loaded or with small load swings), so the BACT guideline was rescinded. Therefore, a project-specific BACT analysis will be performed to determine BACT for the proposed natural gas-fired ammonia synthesis startup heater in this project.

District Rule 4320 includes a compliance option that limits units with heat input ratings greater than 20 MMBtu/hr to 7 ppm @ 3% O_2 for the standard NOx schedule. The rule also contains an enhanced schedule option that allows applicants additional time to meet the requirements of the rule. The enhanced schedule NO_X emission limit is 5 ppmv @ 3% O_2. These levels will be considered as BACT control options for NOx.

Because of the proposed limited use of the proposed startup heater[46] and the applicant's proposal to pay an annual emission fee as allowed in Rule 4320 Section 5.1.2, a third NOx control of 9 ppm @ 3% O2 is proposed. This value is based on the option in Rule 4320 Table 1, Category E that is the NOx emissions level available to units limited to 30 billion Btu/year, which the proposed unit will meet. Therefore, the 9 ppmvd-NOx option will also be included among the possible control technologies to be included in the analysis, and it will be deemed to be the Achieved in Practice option while the lower values will be deemed Technologically Feasible.

Thus, the following controls are identified as possible control technologies:

1. 5 ppmvd @ 3% O2 with SCR - Technologically Feasible
2. 7 ppmvd @ 3% O2 - Technologically Feasible.
3. 9 ppmvd @ 3% O2 - Achieved in Practice

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 5 ppmvd @ 3% O2 with SCR - Technologically Feasible
2. 7 ppmvd @ 3% O2 - Technologically Feasible.
3. 9 ppmvd @ 3% O2 - Achieved in Practice

[46] The startup heater will be limited to no more than 7.84 billion Btu/year heat input , which is equivalent to140 hours at full capacity.

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis is required for technologically feasible control options that are not proposed. The applicant is proposing a NO_X limit of 9 ppmvd @ 3% O_2; therefore, a cost effective analysis is required for the 5 ppmv-NOx and the 7 ppmv-NOx levels, which would be achieved with SCR.

SCR to Achieve 5 and 7 ppmv-NOx:

Assumptions:

In order to determine the cost effectiveness of the two lower emission levels, the cost effectiveness of the two lower emission levels must be compared to the industry standard. Industry standard for a boiler/heater is assumed to be a NO_X emission rate of 15 ppmv @ 3% O_2 (0.018 lb/MMBtu) in accordance with District Rule 4306.

Calculations:

In order to calculate the annual emission reductions for each of the BACT emissions levels identified as Technologically Feasible, the unit's maximum annual emissions at each of the rates needs to be calculated as shown below to compare them to the industry standard level of 15 ppmv-NOx.

The maximum annual emissions are calculated by multiplying the maximum annual heat input rate limit of 7700 MMBtu/yr (which will be imposed on S-7616-33 as a limit) and the emissions factor for each of the corresponding controls. The potential emissions at each of the three emission levels are calculated as follows:

Industrial Standard (15 ppmv-NOx)	= (7,840 MMBtu/yr)(0.018 lb/MMBtu) = 141.1 lb-NOx/yr
Technically Feasible (7 ppmv-NOx)	= (7,840 MMBtu/yr)(0.008 lb/MMBtu) = 62.7 lb-NOx/yr
Technically Feasible (5 ppmv-NOx)	= (7,840 MMBtu/yr)(0.0062 lb/MMBtu) = 48.6 lb-NOx/yr

Cost Analysis:

In order to control emissions down to 7 ppm-NOx or 5 ppm-NOx, a selective catalytic reduction (SCR) system which includes a forced draft system will need to be installed. The applicant has provided documentation estimating the capital cost at the SCR at $300,000 and the cost of a forced draft system at $216,000, for a total capital cost of $516,000.

Total Estimated Capital Cost: **$516,000**

Equivalent Annual Capital Cost (Capital Recovery)

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1}$$ where;

A = Equivalent Annual Control Equipment Capital Cost
P = Present value of the control equipment, including installation cost
i = interest rate (use 10%, or demonstrate why alternate is more representative of the specific operation).
n = equipment life (assume 10 years or demonstrate why alternate is more representative of the specific operation)

Where

P = $516,000
i = 10%,
n = 10 years
A = $83,977

Total annualized cost = $83,977/yr [47]

NOx Reduction due to Selective Catalytic Reduction system:

Total reduction for 7 ppm-NOx control = Emissions $_{15\ ppm}$ – Emissions $_{5\ ppm}$
= 141.1 lb-NOx/yr – 62.7 lb-NOx/yr
= 78.4 lb-NOx/yr
= 0.039 ton-NO_X/yr

Total reduction for 5 ppm-NOx control = Emissions $_{15\ ppm}$ – Emissions $_{5\ ppm}$
= 141.1 lb-NOx/yr – 48.6 lb-NOx/yr
= 92.5 lb-NOx/yr
= 0.046 ton-NO_X/yr

Cost effectiveness:

Cost effectiveness = Cost of control / Emission reduction

Cost effectiveness of 7 ppm-NOx control = $83,997/yr / 0.039 ton-NOx/yr
= $2,153,769 /ton-NOx reduced

Cost effectiveness of 5 ppm-NOx control = $83,997/yr / 0.046 ton-NOx/yr
= $1,826,022 /ton-NOx reduced

The cost of the SCR is greater than the $24,500/ton-NOx cost effectiveness threshold of the District BACT policy. Therefore the use of SCR with ammonia injection to achieve NOx emissions of 5 ppm-NOx and 7 ppm-NOx is not cost effective and is not required as BACT.

[47] As is shown below, due to the limited use of the startup heater, the cost of the SCR system alone makes the SCR system cost ineffective, so the additional operating costs associated with the SCR were not included in the total annualized cost.

The applicant proposes the remaining NOx control for BACT, 9 ppmv.

e. Step 5 - Select BACT

BACT for NO_X emissions for the proposed startup heater is 9 ppmvd @ 3% O_2. The applicant has proposed a NO_X limit of 9 ppmvd @ 3% O_2; therefore BACT for NO_X emissions is satisfied.

2. BACT Analysis for VOC, SOx, CO, and PM_{10} Emissions:

a. Step 1 - Identify all control technologies

The District adopted District Rule 4320 (Advanced Emissions Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) on October 16, 2008. The NO_X emission limit requirements in District Rule 4320 are lower than the limits in formerly-applicable BACT Guideline 1.1.2 (Boiler: > 20 MMBtu/hr, natural gas fired, base-loaded or with small load swings), so the BACT guideline was rescinded. Therefore, a project-specific BACT analysis will be performed to determine BACT for this project.

The SJVUAPCD BACT Clearinghouse guideline 1.1.2 identifies the following technologies for the control of VOC, SOx, CO, and PM10.

1. Natural gas fuel with LPG backup

b. Step 2 - Eliminate Technologically Infeasible Options

The above listed technology is technologically feasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

d. Step 4 - Cost Effectiveness Analysis

Only one control technology identified and this technology is achieved in practice, therefore, cost effectiveness analysis not necessary.

e. Step 5 - Select BACT for VOC, SOx, CO, and PM_{10}

BACT is the use of natural gas with LPG backup. The applicant has proposed the use of PUC-quality natural gas; therefore, BACT for VOC, SOx, CO, and PM_{10} emissions is satisfied.

Top Down BACT Analysis for the Nitric Acid Plant (S-7616-35)

1. BACT Analysis for NOx Emissions:

a. Step 1 - Identify all control technologies

A BACT guideline prepared for the SJVUAPCD BACT Clearinghouse that was approved for this project identifies the following control technologies for NOx emissions for nitric acid plants:

1. Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis – Technologically Feasible
2. Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.50 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis – Achieved in Practice

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1. Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis
2. Extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.50 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NOx for the nitric acid plant is extended absorption and/or catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis. The applicant has proposed catalytic reduction, with NOx emissions no greater than 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid), on a 24-hour rolling average basis. Therefore, BACT for NOx is satisfied.

Top Down BACT Analysis for the Ammonium Nitrate Unit (S-7616-36)

1. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

A BACT guideline prepared for the SJVUAPCD BACT Clearinghouse that was approved for this project identifies the following control technologies for PM10 emissions for ammonium nitrate units:

1. Wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced – Technologically Feasible
2. Wet scrubber system – Achieved in Practice

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1. Wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced
2. Wet scrubber system

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM10 for the ammonium nitrate unit is the use of a wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced. The applicant has proposed the use of a wet scrubber system with PM10 emissions limited to no more than 0.0075 lb-PM10/ton of ammonium nitrate produced. Therefore, BACT for PM10 is satisfied.

Top Down BACT Analysis for the Emergency IC Engines (S-7616-38, -39, -40)

1. BACT Analysis for NOx, CO, VOC, PM10, and SOx Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.1.1 identifies achieved in practice BACT for emissions from emergency diesel IC engines as follows:

Pollutant	Achieved in Practice
CO, NOx, VOC	Latest EPA Tier Certification level for applicable horsepower range
PM10	0.15 g/hp-hr or the Latest EPA Tier Certification level for applicable horsepower range, whichever is more stringent. (ATCM)
SOx	Very low sulfur diesel fuel (15 ppmw sulfur or less)

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from Step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because only one control option is listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control option listed for each pollutant. Therefore, a cost effectiveness analysis is not required.

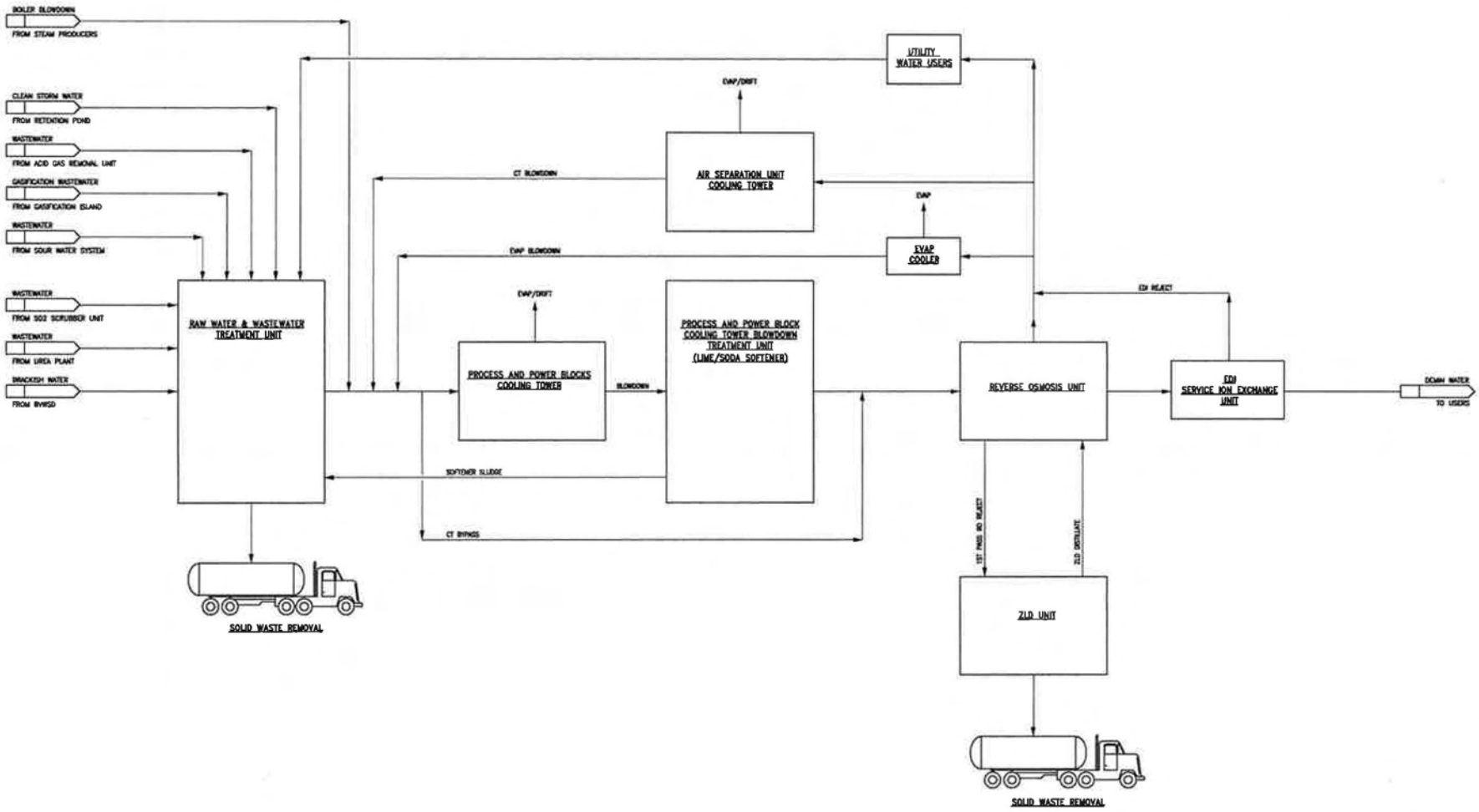
e. Step 5 - Select BACT

BACT for CO, NOx, VOC emissions for these emergency standby diesel IC engines is the latest EPA Tier Certification level for the applicable horsepower range. The applicant has proposed to install three interim Tier 4 engines, which will be the latest EPA Tier Certification level for the applicable horsepower range at the time of installation.

BACT for PM10 is 0.15 g/hp-hr, or the latest EPA Tier Certification level for the applicable horsepower range, whichever is more stringent. The applicant is proposing engines that meet this requirement. Engines S-7616-38 and -39 will be limited to 0.07 g-PM10/bhp-hr, and engine S-7616-40 will be limited to 0.01 g-PM10/bhp-hr.

BACT for SOx is the use of very low sulfur diesel fuel (15 ppmw sulfur or less). The applicant is proposing the use of CARB-certified diesel fuel that is rated at 15 ppmw sulfur or less. Therefore, BACT is satisfied for these pollutants.

APPENDIX D
Process Flow Diagrams



FLOW DIAGRAM: RAW WATER/WASTEWATER/ DEMIN WATER TREATMENT PLANT

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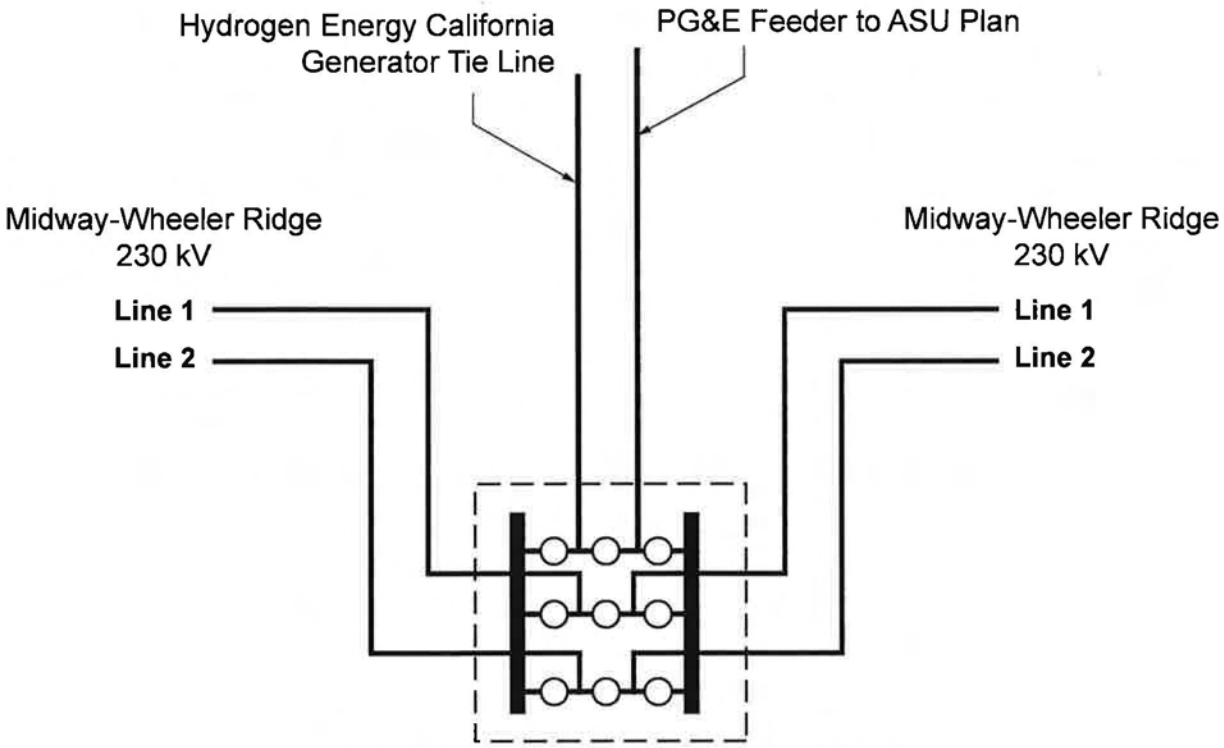
FIGURE 2-11

Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Raw Water/Wastewater/Demin Water Treatment Plant; Drawing No: A4UV-090-25-SK-0001, Rev. 0 (2/27/12)

vsd_215912 U:\DOE\HECA\Figures\HECA_2012WasteWater_Flow\2-11_flow_da_water_treatment.vsd



Proposed 230 kV Switching Station
(at Olean Avenue and Elk Valley Road)

Schematic: No Scale

OVERALL SINGLE-LINE DIAGRAM

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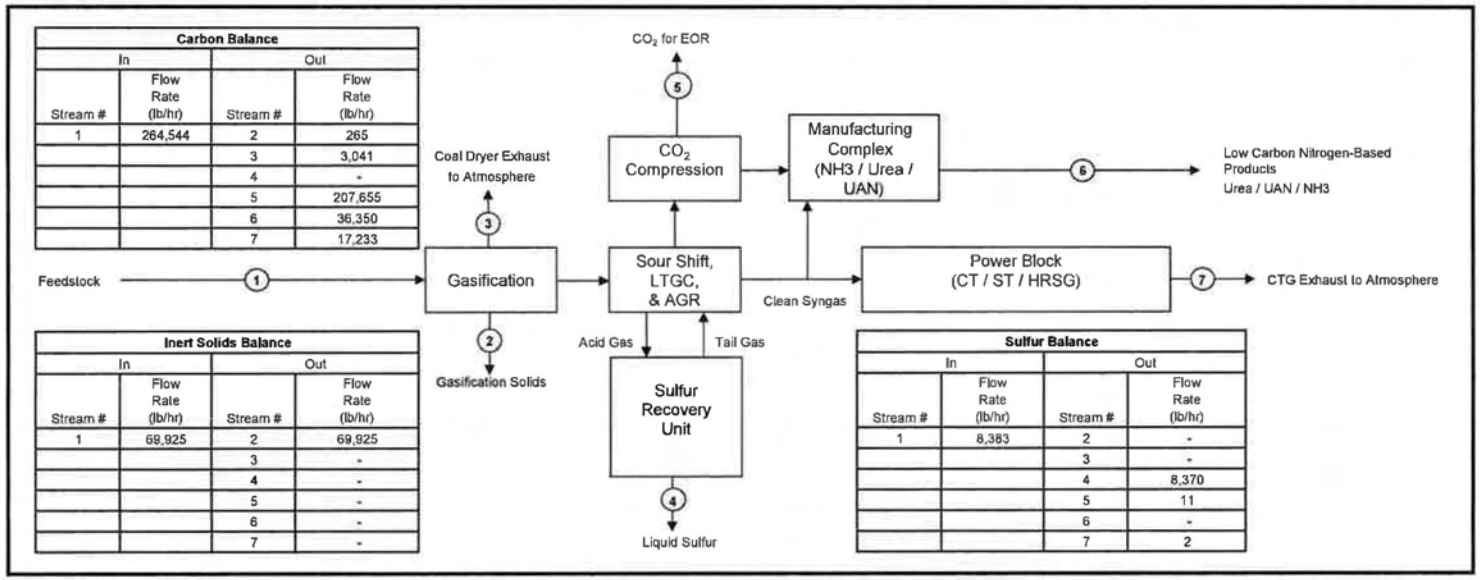
FIGURE 2-12

4/26/12 vsa...T:\HECA-SCS 2012\GRAPHICS 2012\2.0_Proj Description\2-12_overall_single_line.ai



Notes:
1. Only inert solids contained in the Feedstock is shown in the solids balance. All other feedstock components are excluded.
2. A water balance is provided in drawing A4UV-090-25-SK-0001.

Source: Fluor, 2012

HECA OVERALL COMPONENT BALANCES

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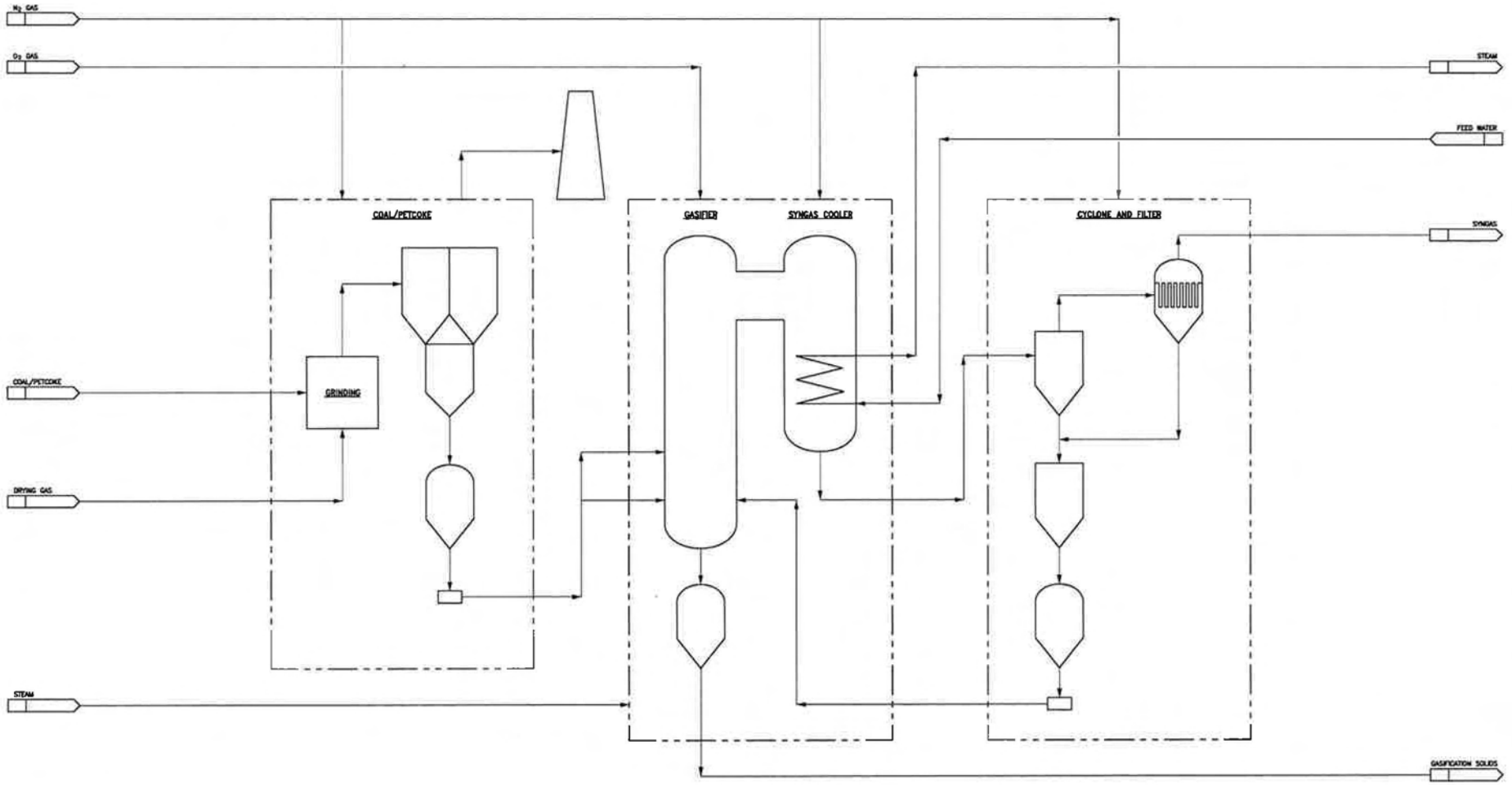
FIGURE 2-13



FLOW DIAGRAM
GASIFICATION PROCESS

Sources:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Gasification Process, Drawing No: A4UV-010-25-SK-0002, Rev. 0 (2/14/12)
Mitsubishi Heavy Industries, Ltd.

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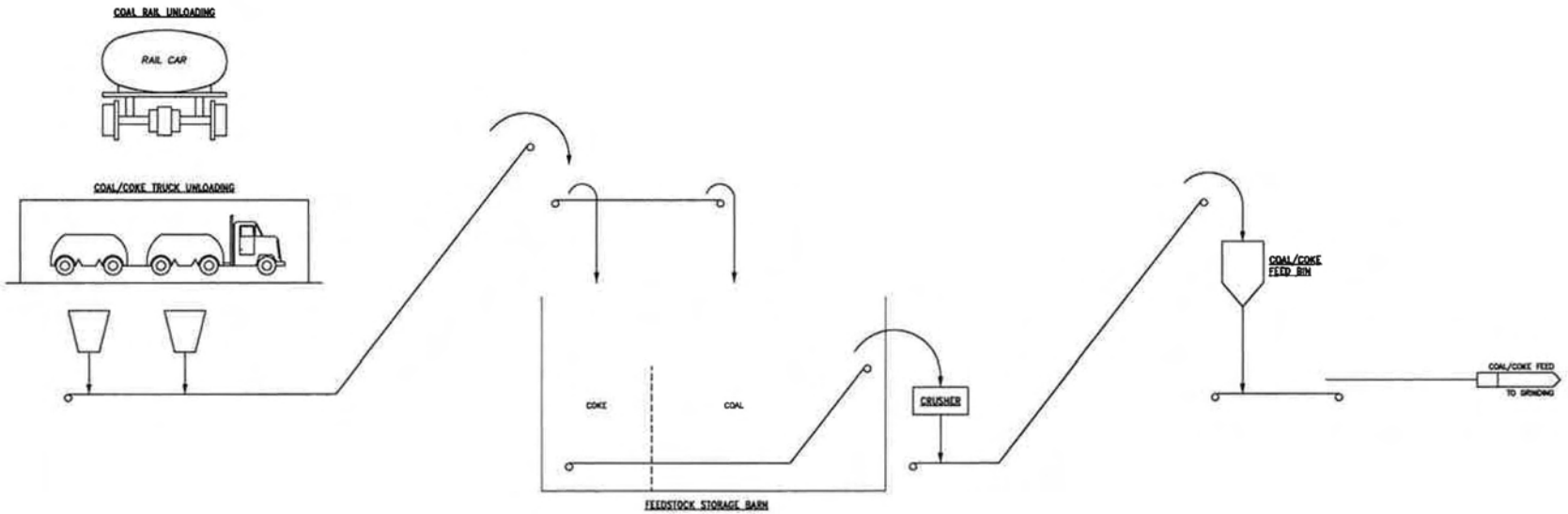
FIGURE 2-14



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Feedstock Handling and Storage; Drawing No: A4UV-010-25-SK-0001, Rev. 0 (2/14/12)

FLOW DIAGRAM
FEEDSTOCK HANDLING AND STORAGE

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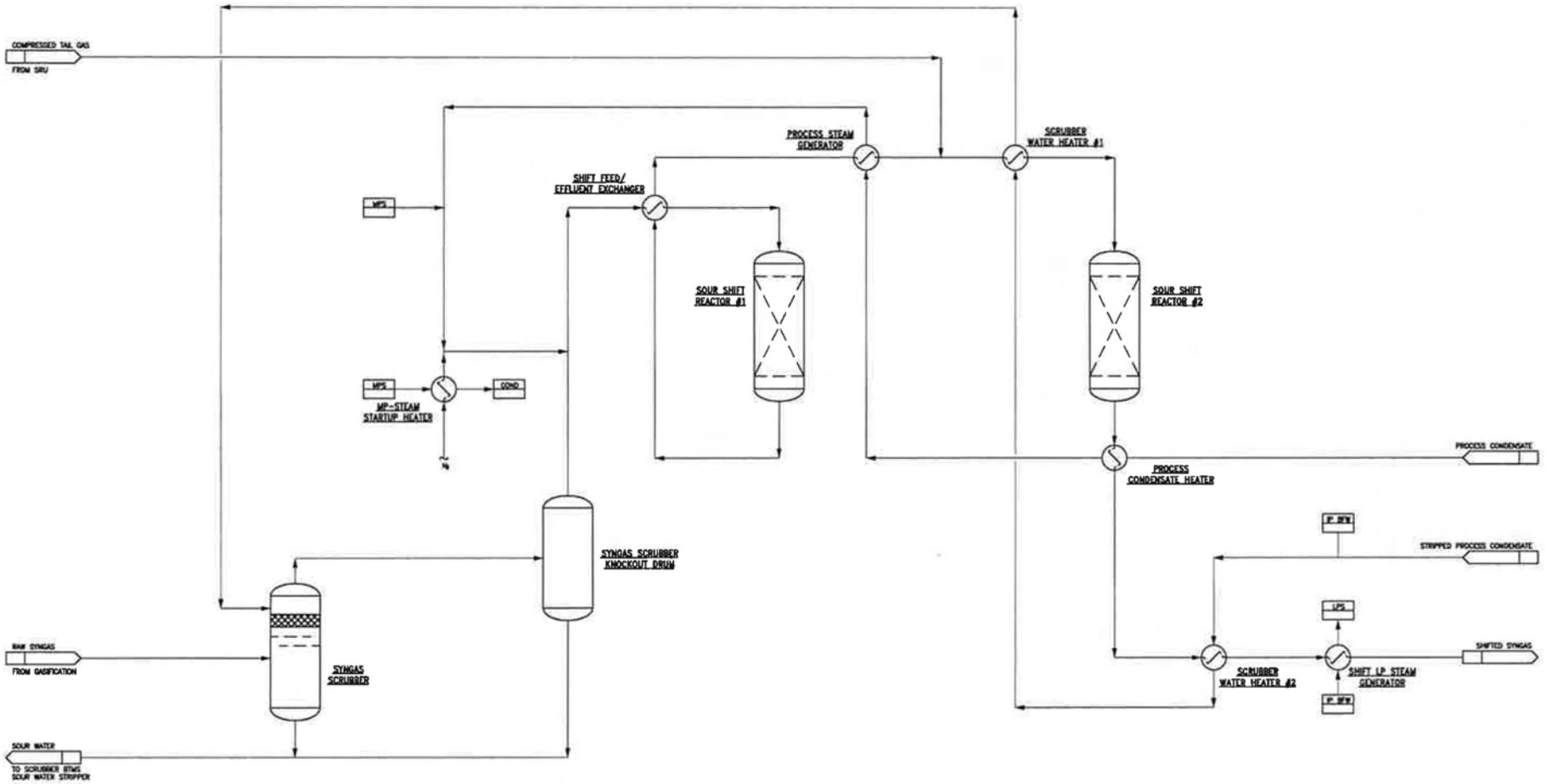
FIGURE 2-15



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Sour Shift System;
Drawing No: A4UV-020-25-SK-0001, Rev. 0 (2/14/12)

FLOW DIAGRAM
SOUR SHIFT SYSTEM

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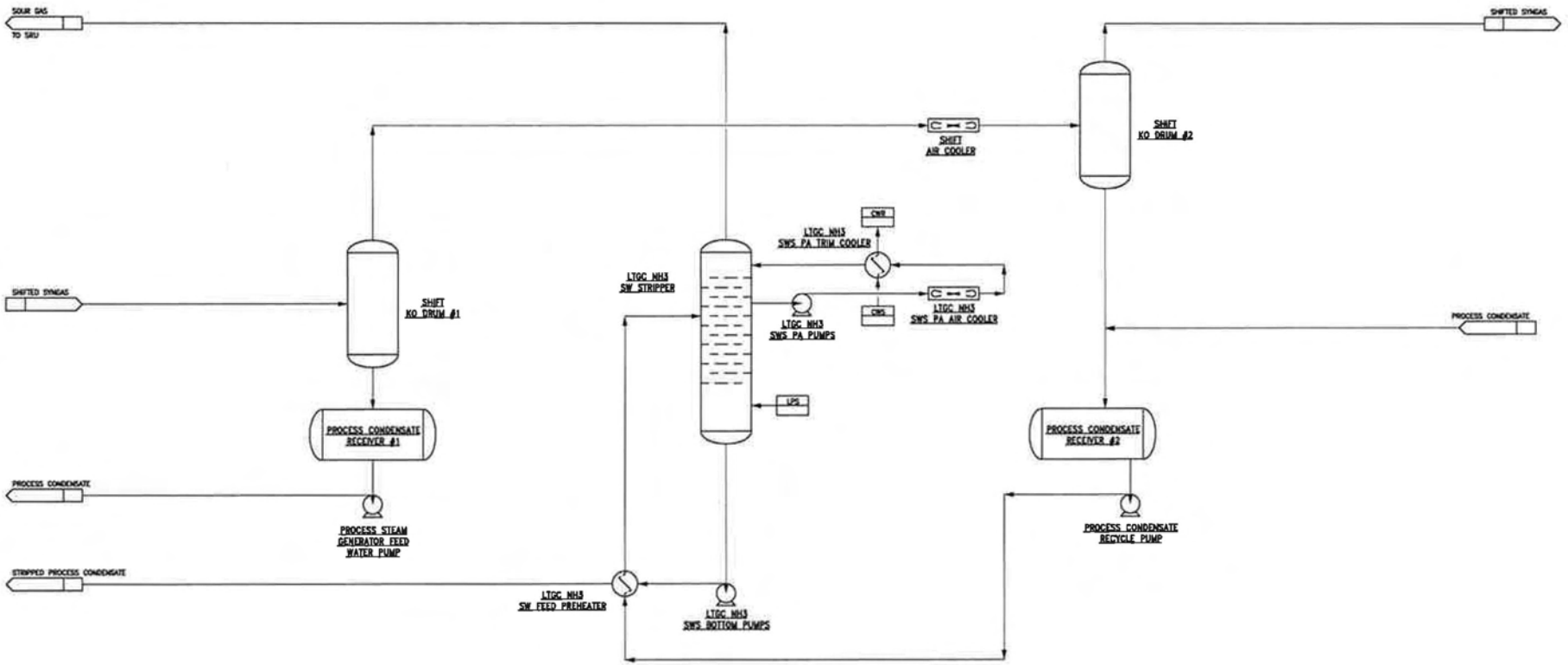
FIGURE 2-16



FLOW DIAGRAM
LOW TEMPERATURE GAS COOLING (LTGC)

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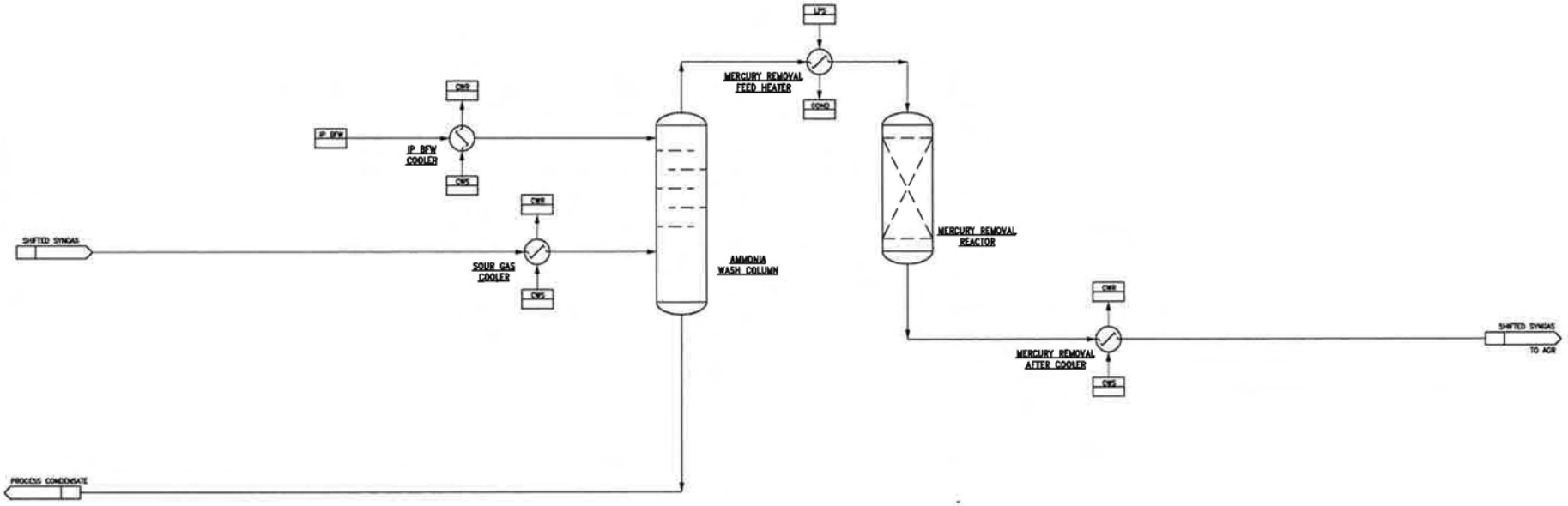
FIGURE 2-17

Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Low Temperature Gas Cooling;
Drawing No: A4UV-020-25-SK-0002, Rev. 0 (2/14/12)

4/02/12 I:\HECA-SCS,2012\GRAPHICS,2012\2.0_Proj Description\2-17_flow_dia_LTGC.ai



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Wash Column and Mercury Removal;
Drawing No: A4UV-020-25-SK-0003, Rev. 0 (2/14/12)

FLOW DIAGRAM
WASH COLUMN AND MERCURY REMOVAL

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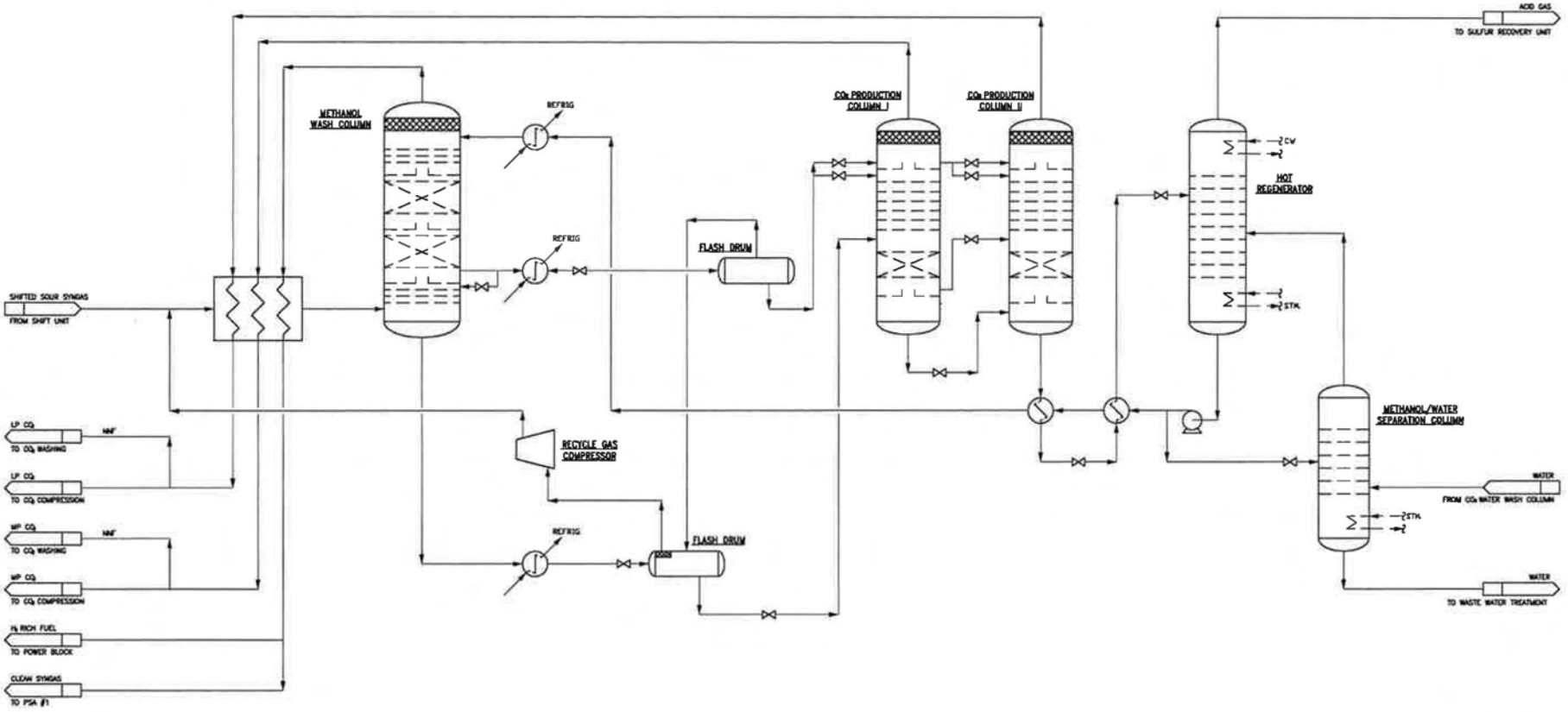
FIGURE 2-18



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Rectisol Acid Gas Removal;
Drawing No: A4UV-030-25-SK-0001, Rev, 0 (2/14/12)

FLOW DIAGRAM
RECTISOL ACID GAS REMOVAL

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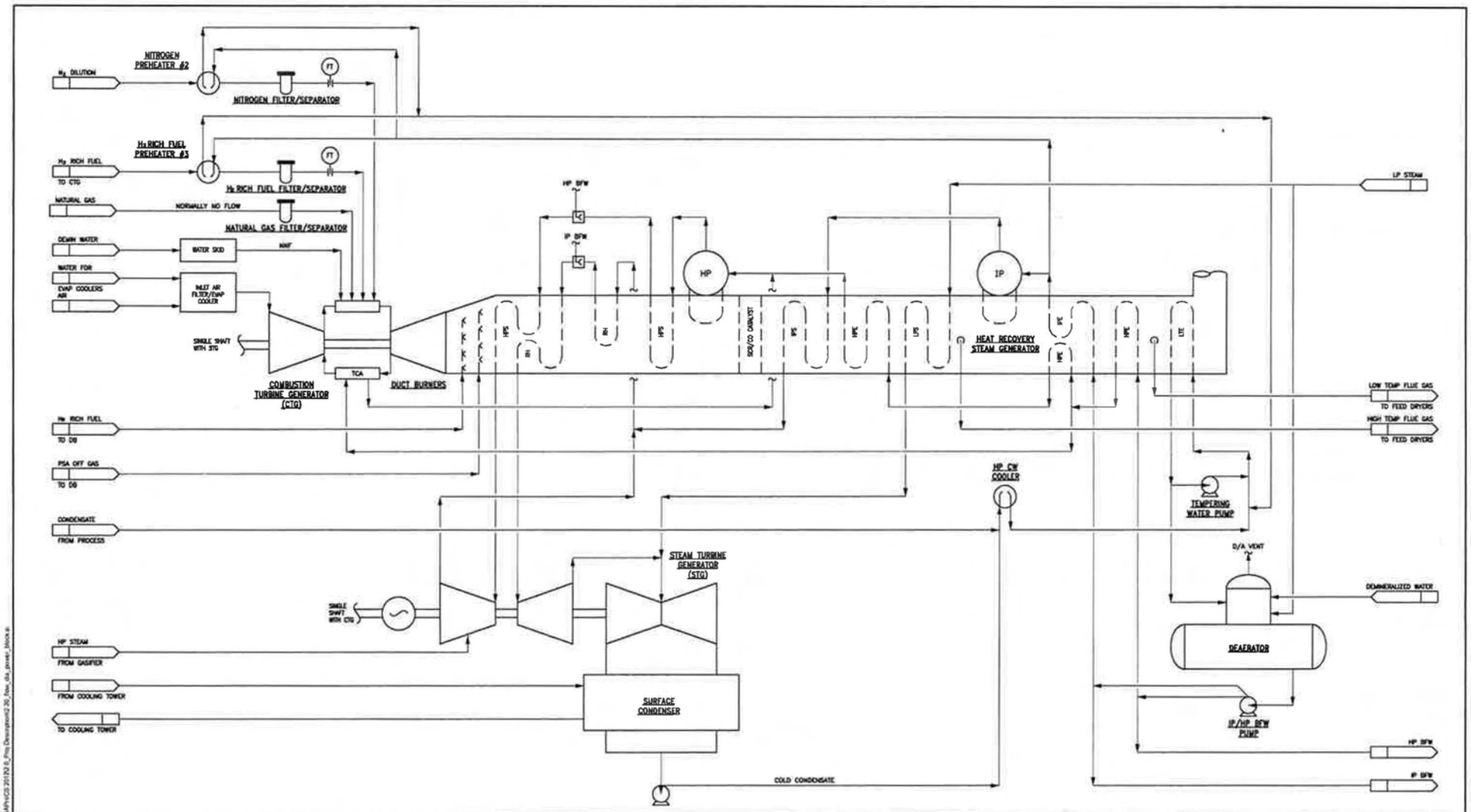
FIGURE 2-19



FLOW DIAGRAM
POWER BLOCK SYSTEMS

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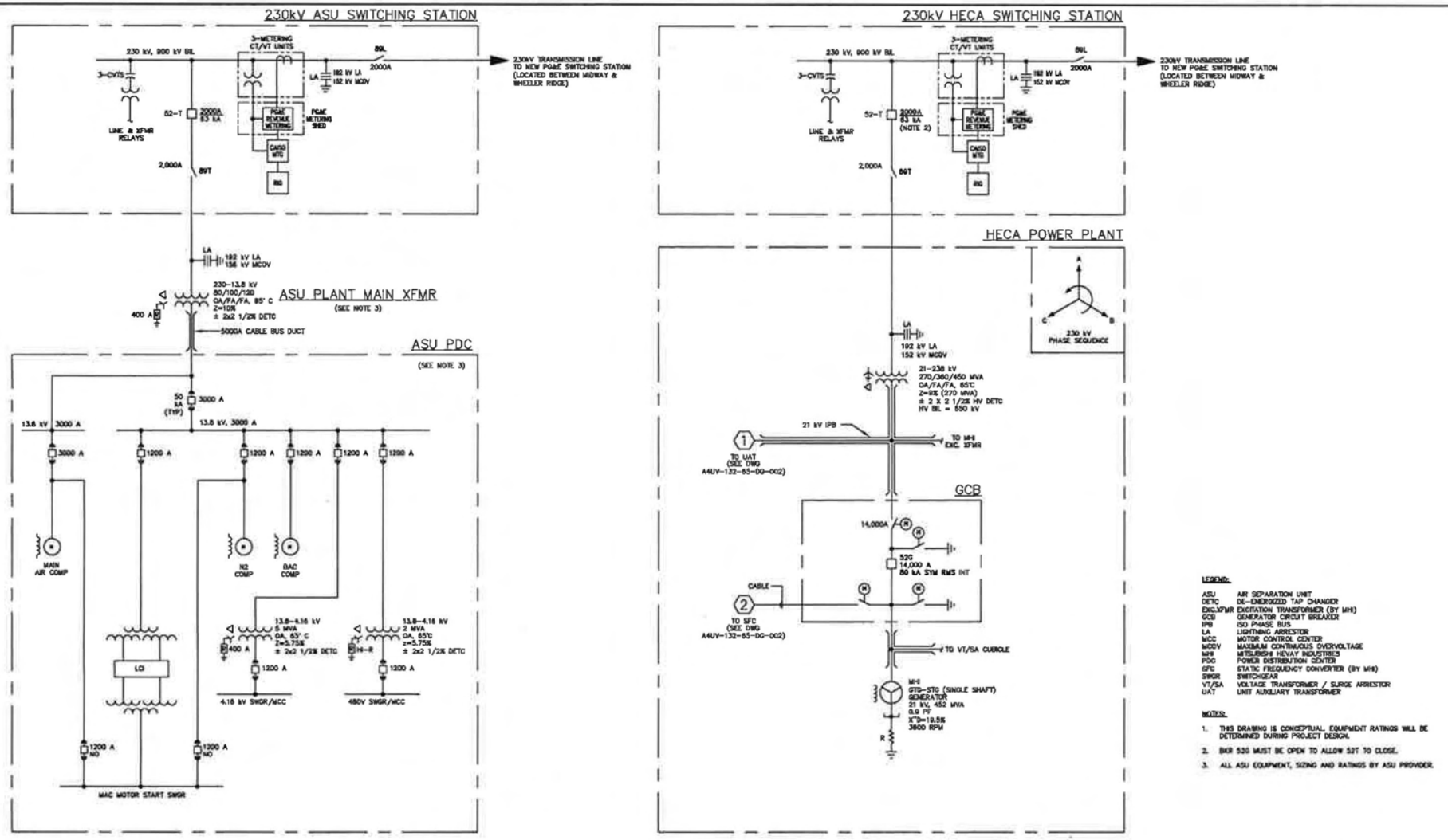
FIGURE 2-20

Source:
Fluor: HECA-SCS, 2012 AFC Update; Flow Diagram Power Block Systems;
Drawing No: A4UV-070-25-SK-0001, Rev. 0 (2/14/12)



Source:
Fluor; HECA-SCS, 2012 AFC Update; Electrical Overall One Line Diagram;
Drawing No. A4UV-132-65-DG-0001, Rev. A (2/08/12)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (1)

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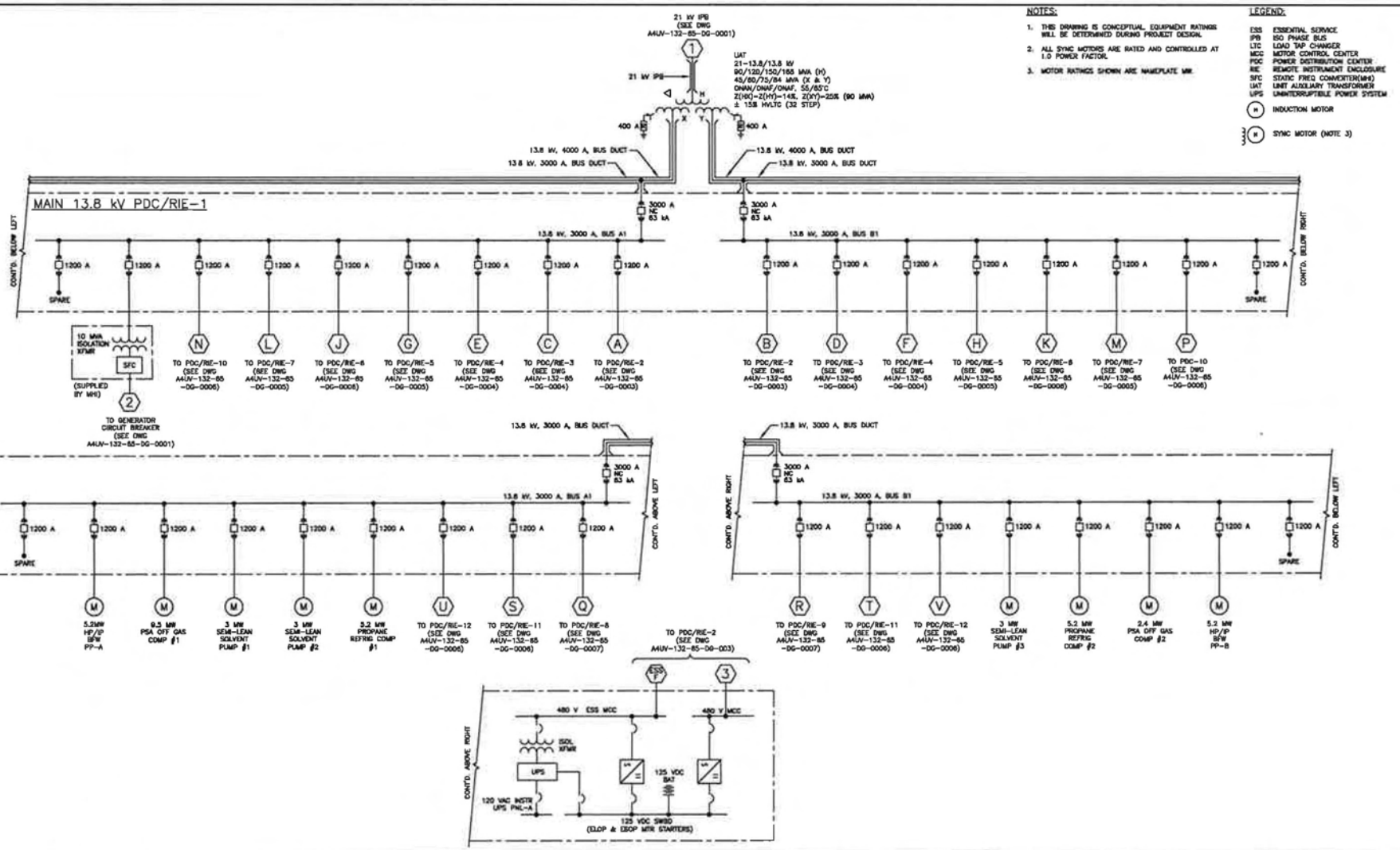
FIGURE 2-21



Source:
Fluor; HECA-SCS, 2012 AFC Update; Electrical Overall One Line Diagram, Drawing No: A4UV-132-65-DG-0002, Rev. A (2/08/12)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (2)

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Kern County, California

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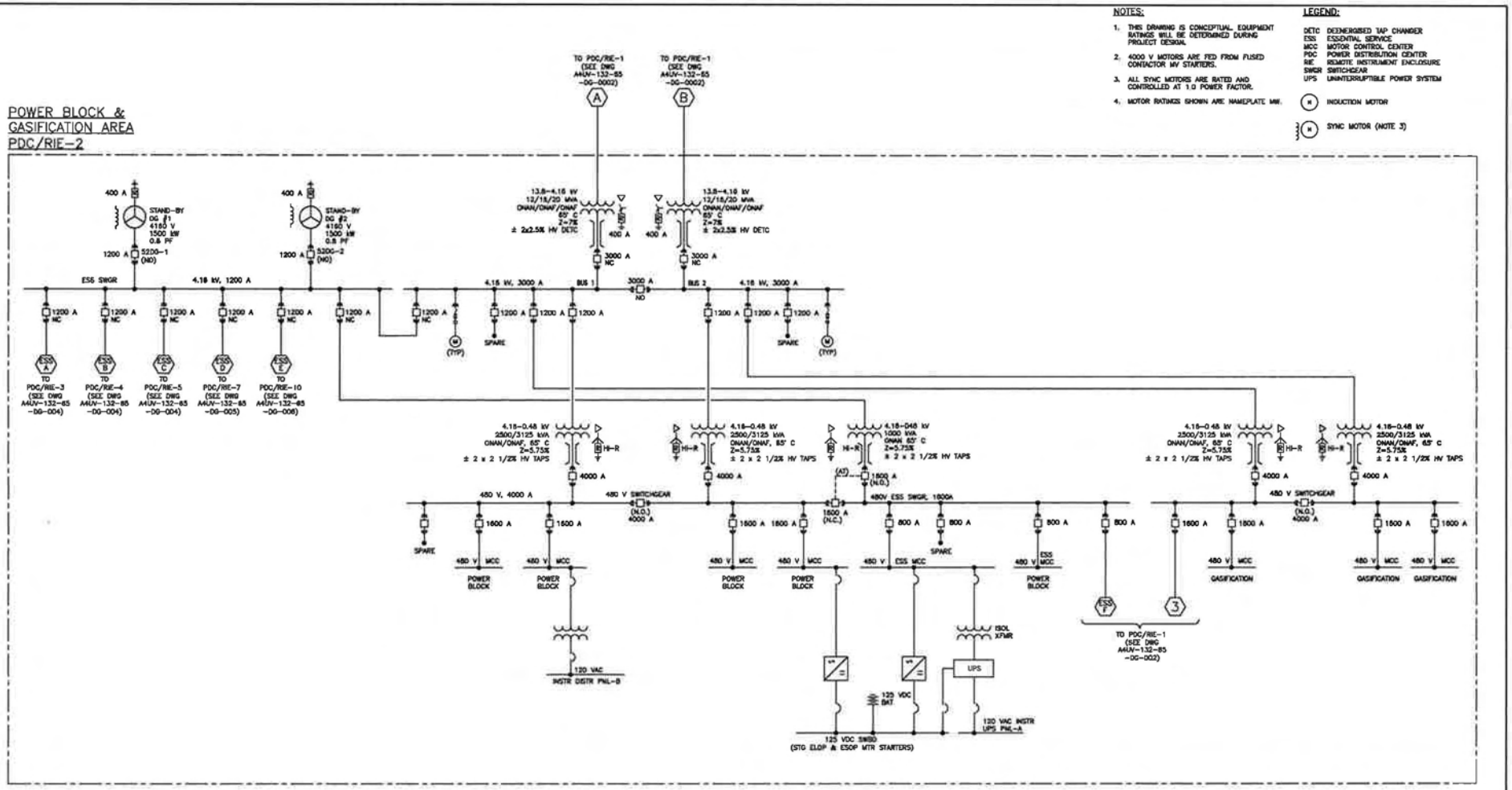
FIGURE 2-22



Source:
Fluor; HECA-SCS, 2012 AFC Update, Electrical Overall One Line Diagram; Drawing No: A4UV-132-65-DG-0003, Rev. A (2/08/12)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (3)

April 2012
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Kern County, California

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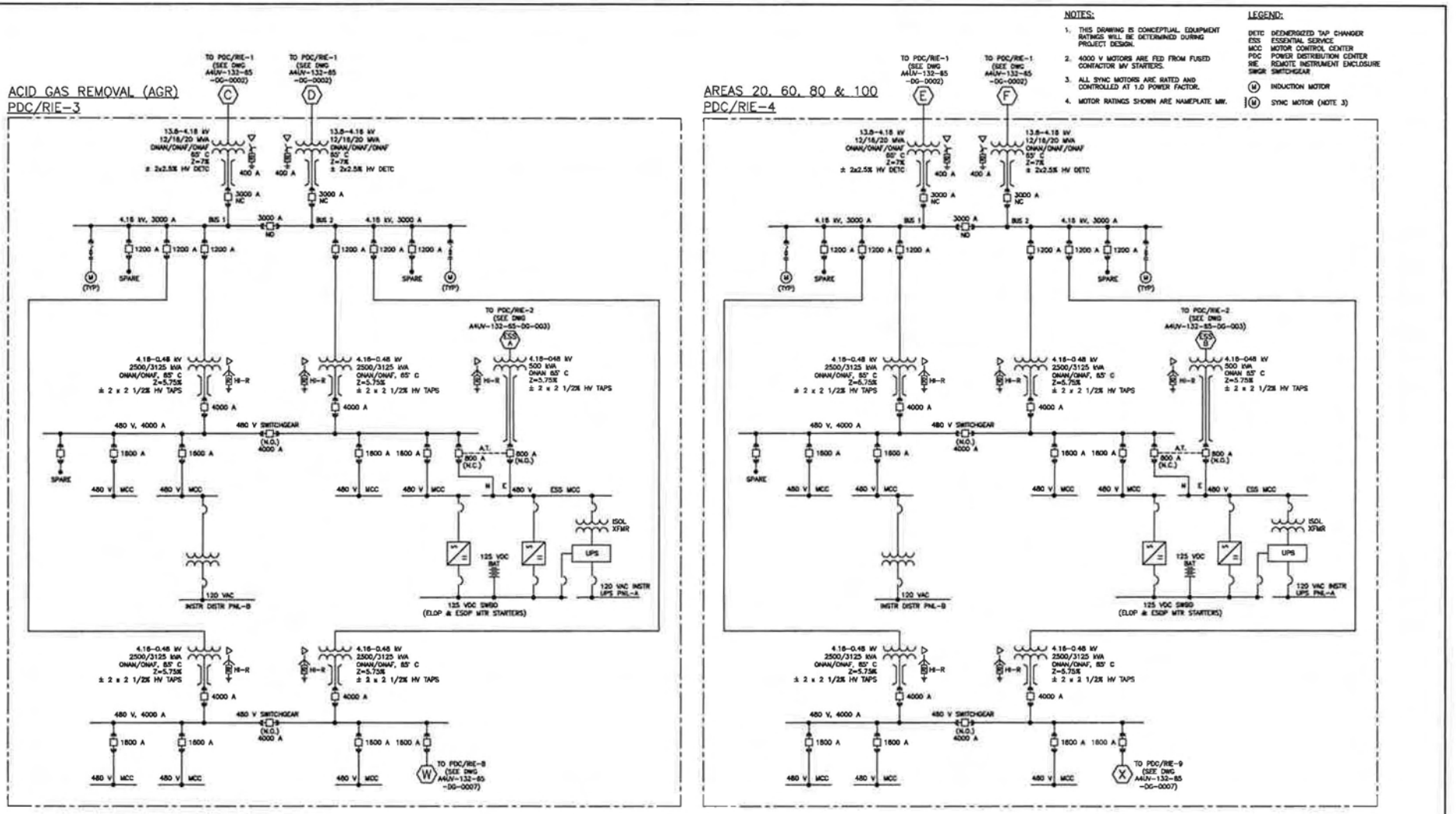
FIGURE 2-23



Source:
Fluor; HECA-SCS, 2012 AFC Update; Electrical Overall One Line Diagram;
Drawing No: A4UV-132-65-DG-0004, Rev. A (2/08/12)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (4)

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Kern County, California

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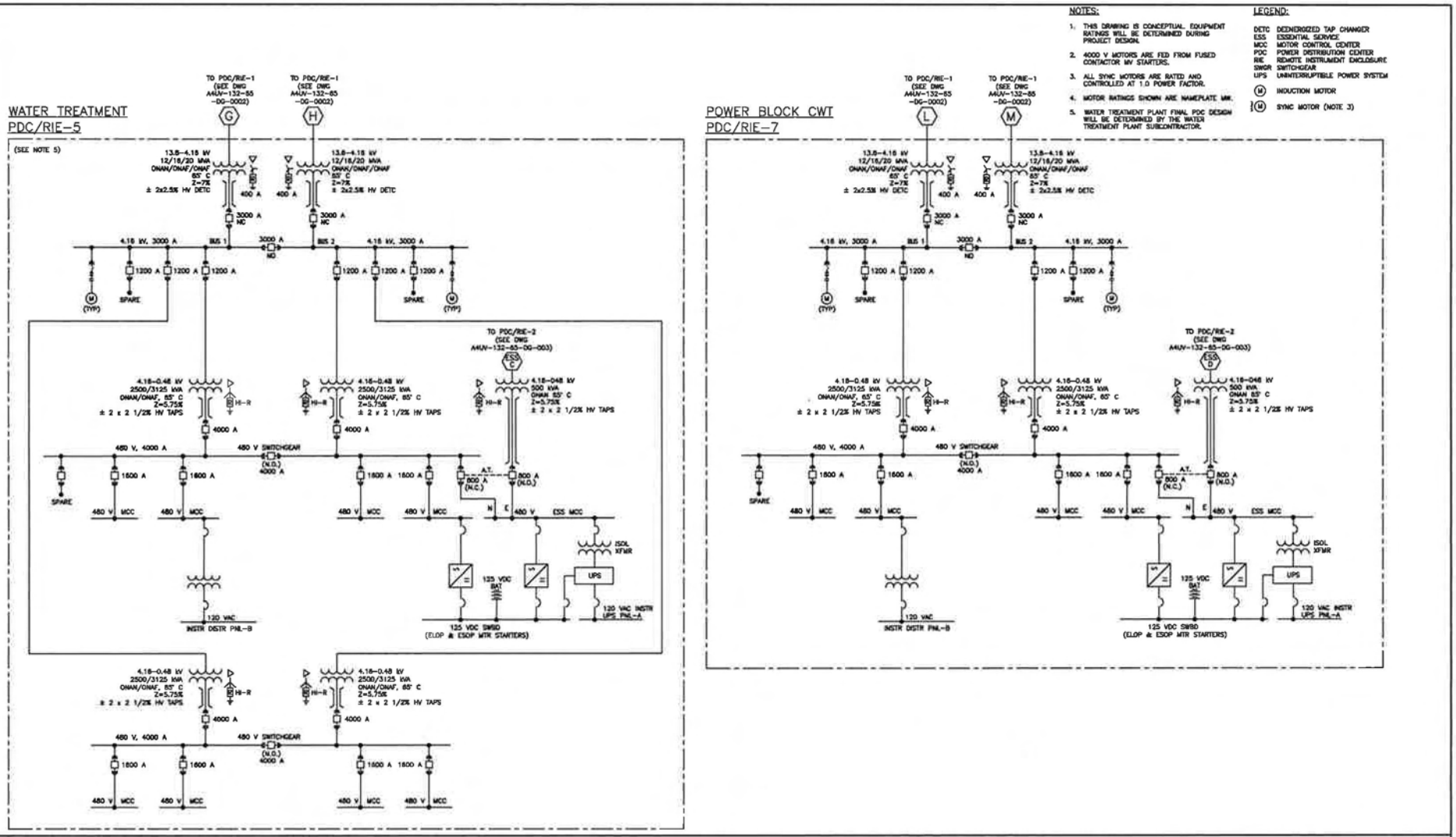
FIGURE 2-24



Source
Fluor; HECA-SCS, 2012 AFC Update, Electrical Overall One Line Diagram, Drawing No: A4UV-132-65-DG-0005, Rev. A (2/08/12)

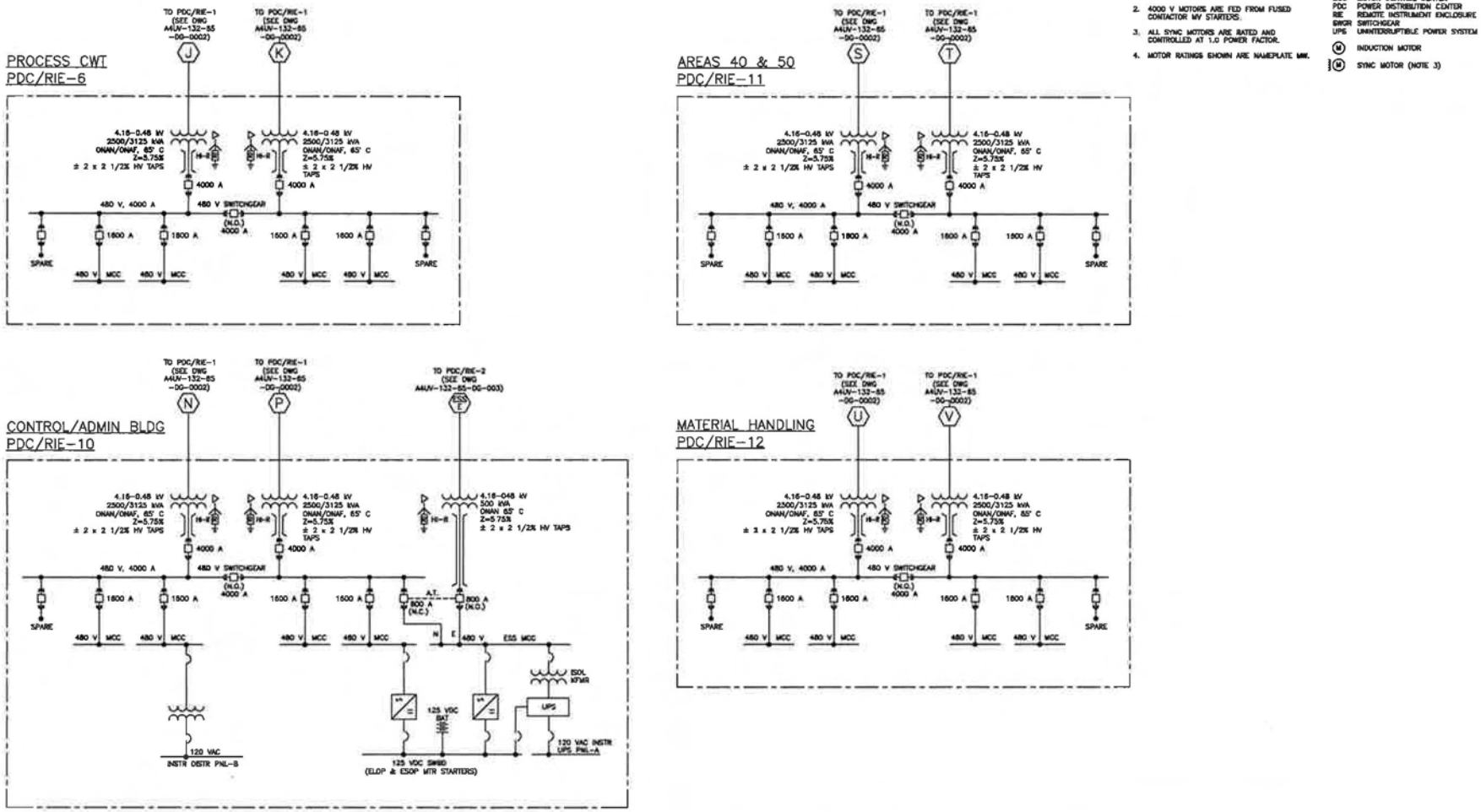
ELECTRICAL
OVERALL ONE-LINE DIAGRAM (5)

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-25



NOTES:

1. THIS DRAWING IS CONCEPTUAL. EQUIPMENT RATINGS WILL BE DETERMINED DURING PROJECT DESIGN.
2. 4000 V MOTORS ARE FED FROM FUSED CONTACTOR MV STARTERS.
3. ALL SYNC MOTORS ARE RATED AND CONTROLLED AT 1.0 POWER FACTOR.
4. MOTOR RATINGS SHOWN ARE NAMEPLATE MW.

LEGEND:

DETC	DEENERGIZED TAP CHANGER
ESS	ESSENTIAL SERVICE
MCC	MOTOR CONTROL CENTER
PDC	POWER DISTRIBUTION CENTER
RIE	REMOTE INSTRUMENT ENCLOSURE
SWGR	SWITCHGEAR
UPS	UNINTERRUPTIBLE POWER SYSTEM

(M) INDUCTION MOTOR

(M) SYNC MOTOR (NOTE 3)

Source
Fluor; HECA-SCS, 2012 AFC Update; Electrical Overall One Line Diagram; Drawing No. A4UV-132-65-DG-0006, Rev. A (2/08/12)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (6)

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-26

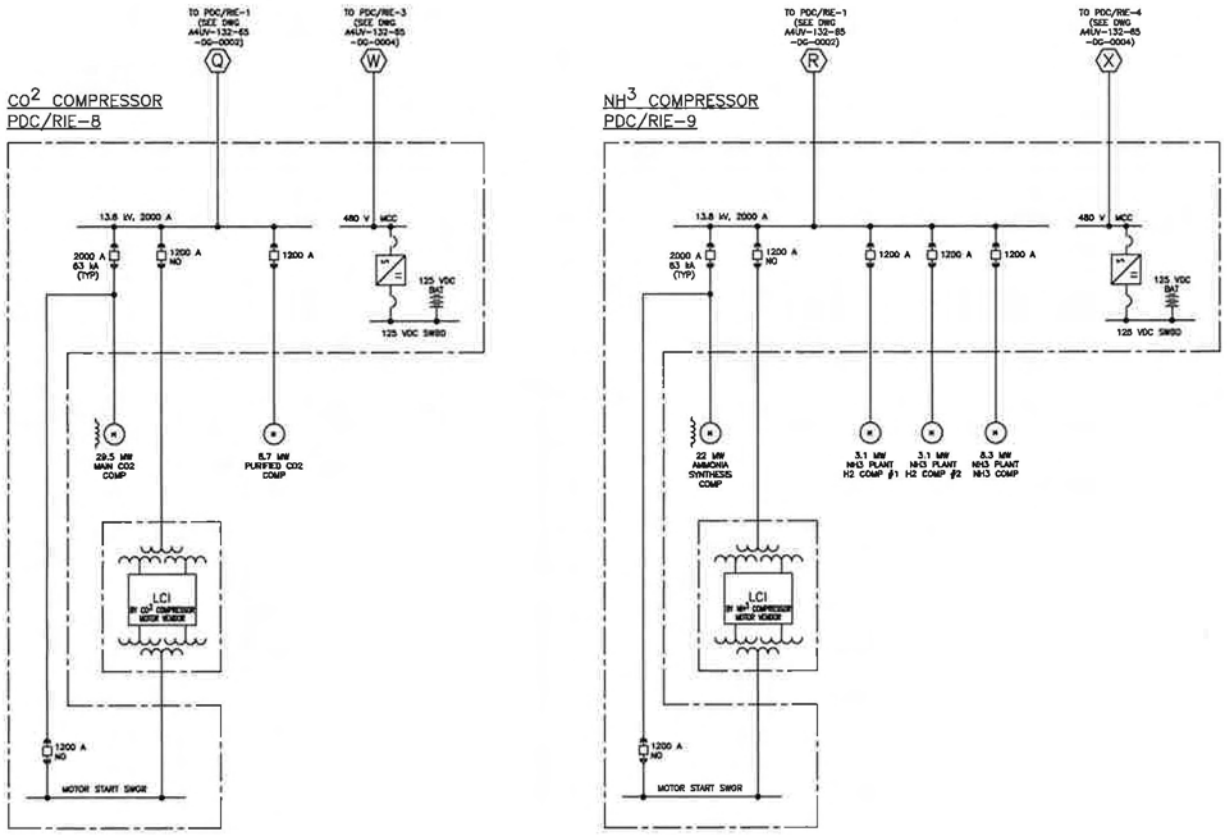
vss 4/02/12 U:\GIS\HECA\Projects\HECA_2012\Industry_Fig\2-26_elect_overall_one-line_8.ai

NOTES:

1. THIS DRAWING IS CONCEPTUAL. EQUIPMENT RATINGS WILL BE DETERMINED DURING PROJECT DESIGN.
2. ALL SYNC MOTORS ARE RATED AND CONTROLLED AT 1.0 POWER FACTOR.
3. MOTOR RATINGS SHOWN ARE NAMEPLATE MW.

LEGEND:

ESB	ESSENTIAL SERVICE
LCI	LOAD COMMUTATED INVERTER
MCC	MOTOR CONTROL CENTER
PDC	POWER DISTRIBUTION CENTER
RIE	REMOTE INSTRUMENT ENCLOSURE
SWGR	SWITCHGEAR
(M)	INDUCTION MOTOR
(M)	SYNC MOTOR (NOTE 3)



Source:
Fluor; HECA-SCS, 2012 AFC Update; Electrical Overall One Line Diagram;
Drawing No: A4UV-132-65-DG-0007, Rev. A (2/08/12)

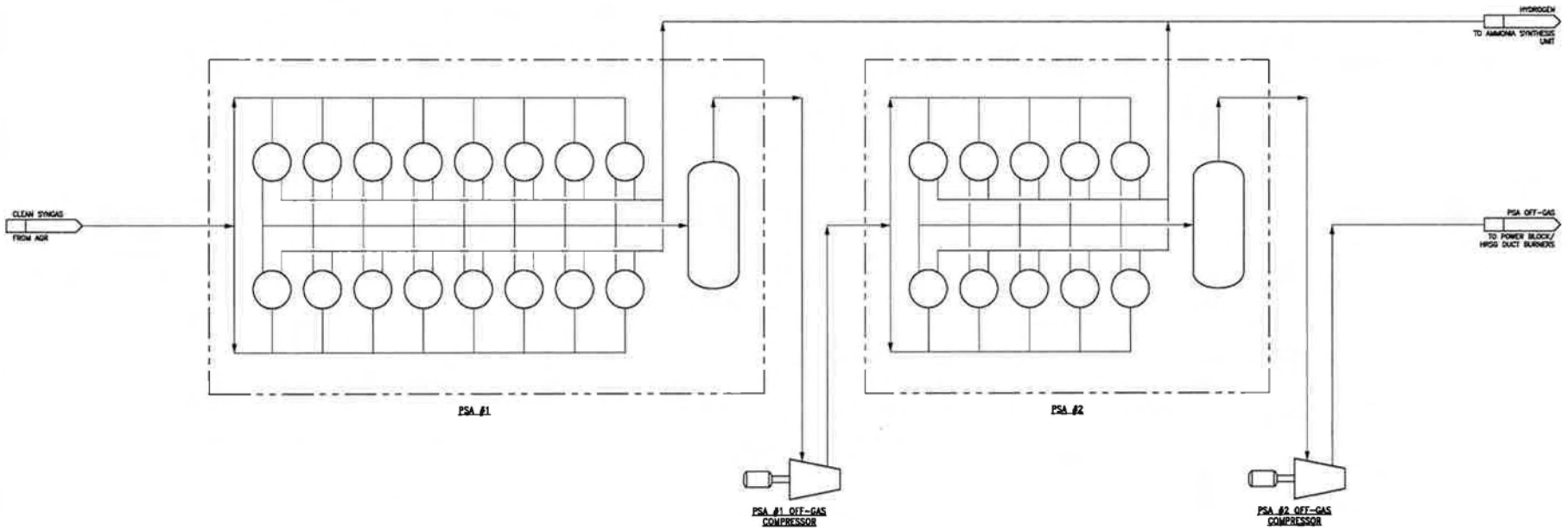
ELECTRICAL
OVERALL ONE-LINE DIAGRAM (7)

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-27



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram PSA and Off-Gas Compression Systems;
Drawing No: A4UV-060-25-SK-0001, Rev. 0 (2/14/12)

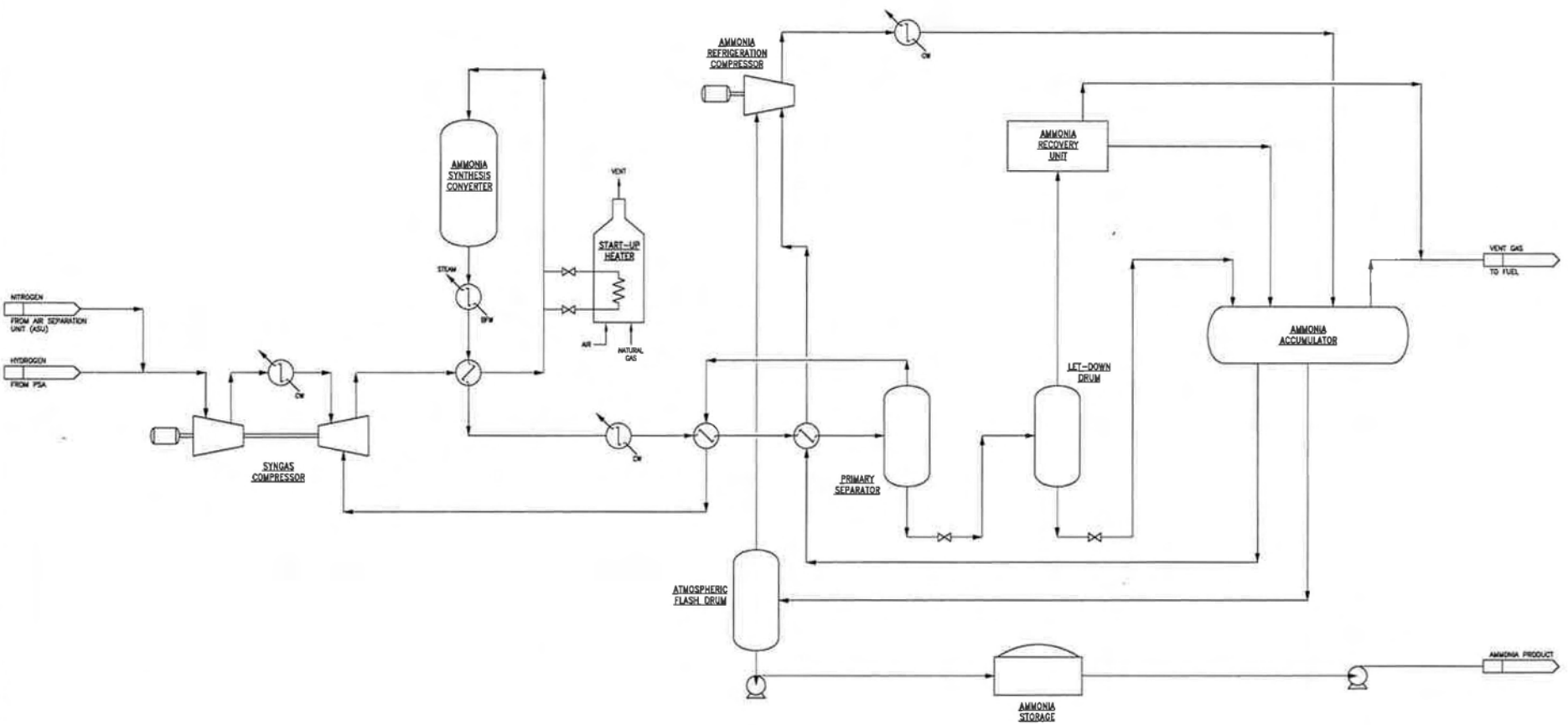
FLOW DIAGRAM
PSA AND OFF-GAS COMPRESSION SYSTEMS

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-28



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Ammonia Synthesis Unit;
Drawing No: A4UV-080-25-SK-0001, Rev. 1 (3/29/12)

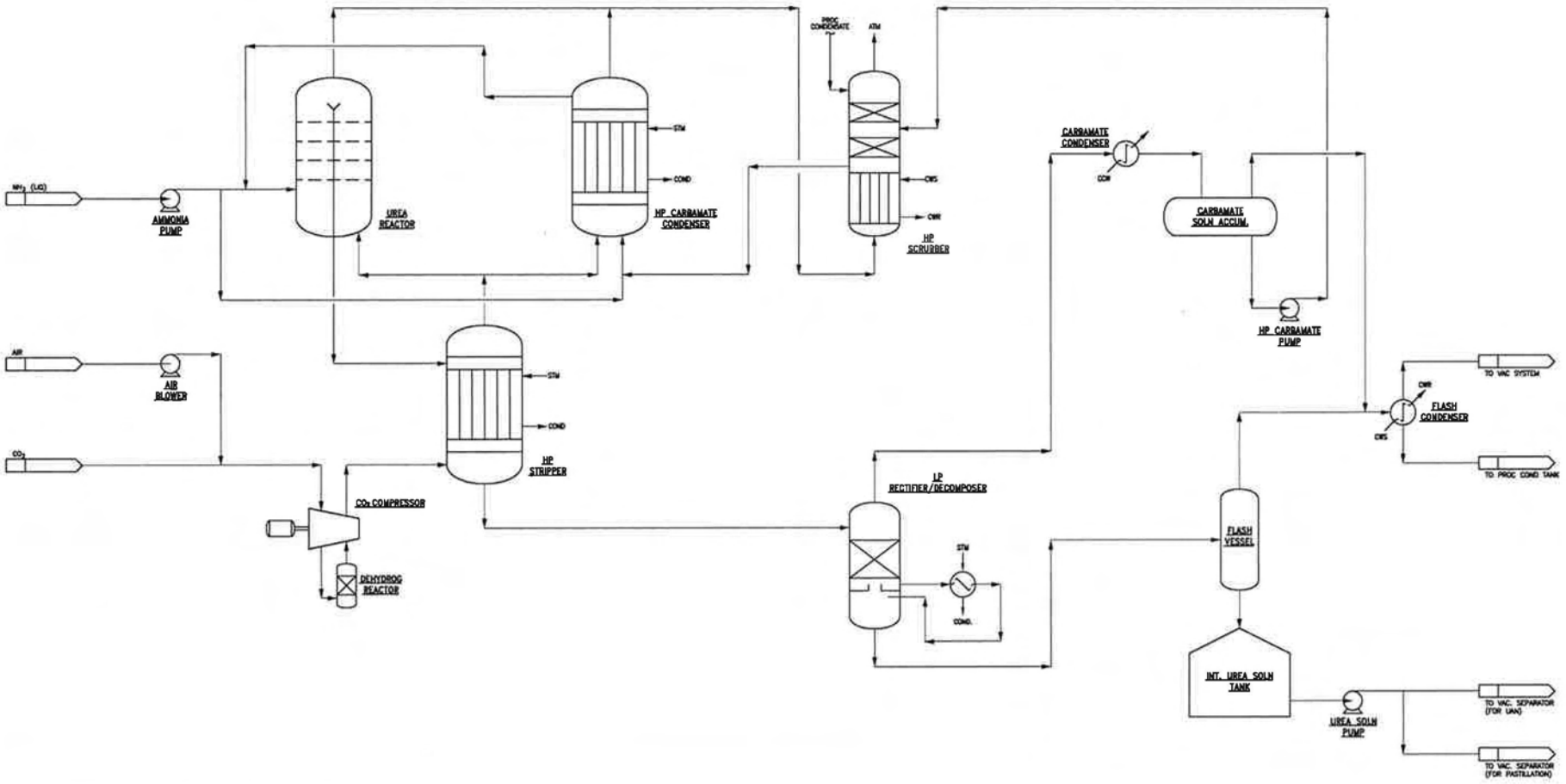
FLOW DIAGRAM
AMMONIA SYNTHESIS UNIT

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-29



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Urea Unit - Synthesis;
Drawing No. A4UV-080-25-SK-0002, Rev. 0 (2/14/12)

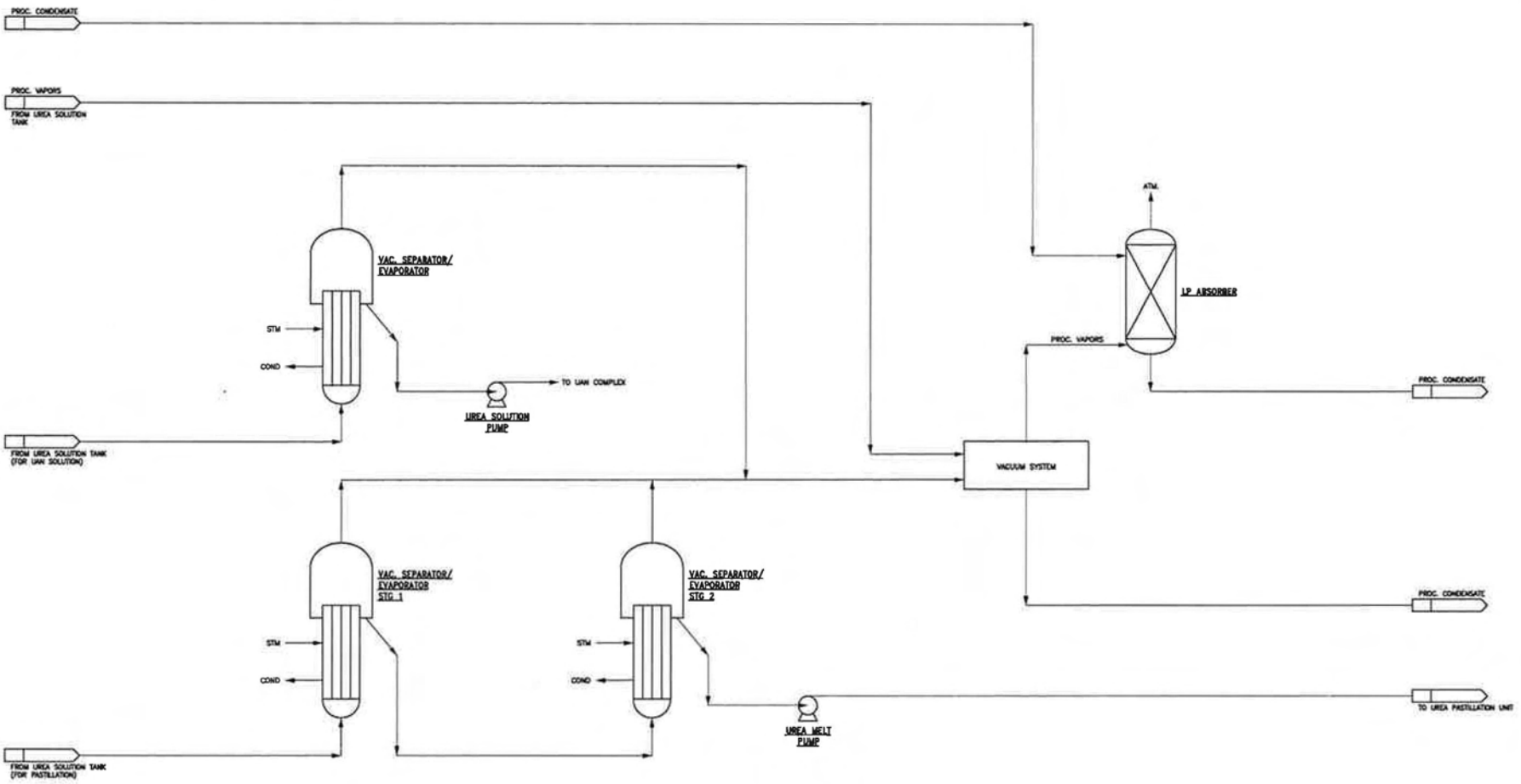
FLOW DIAGRAM
UREA UNIT - SYNTHESIS

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-30



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Urea Unit - Concentration; Drawing No: A4UV-080-25-SK-0003, Rev. 0 (2/14/12)

FLOW DIAGRAM
UREA UNIT - CONCENTRATION

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

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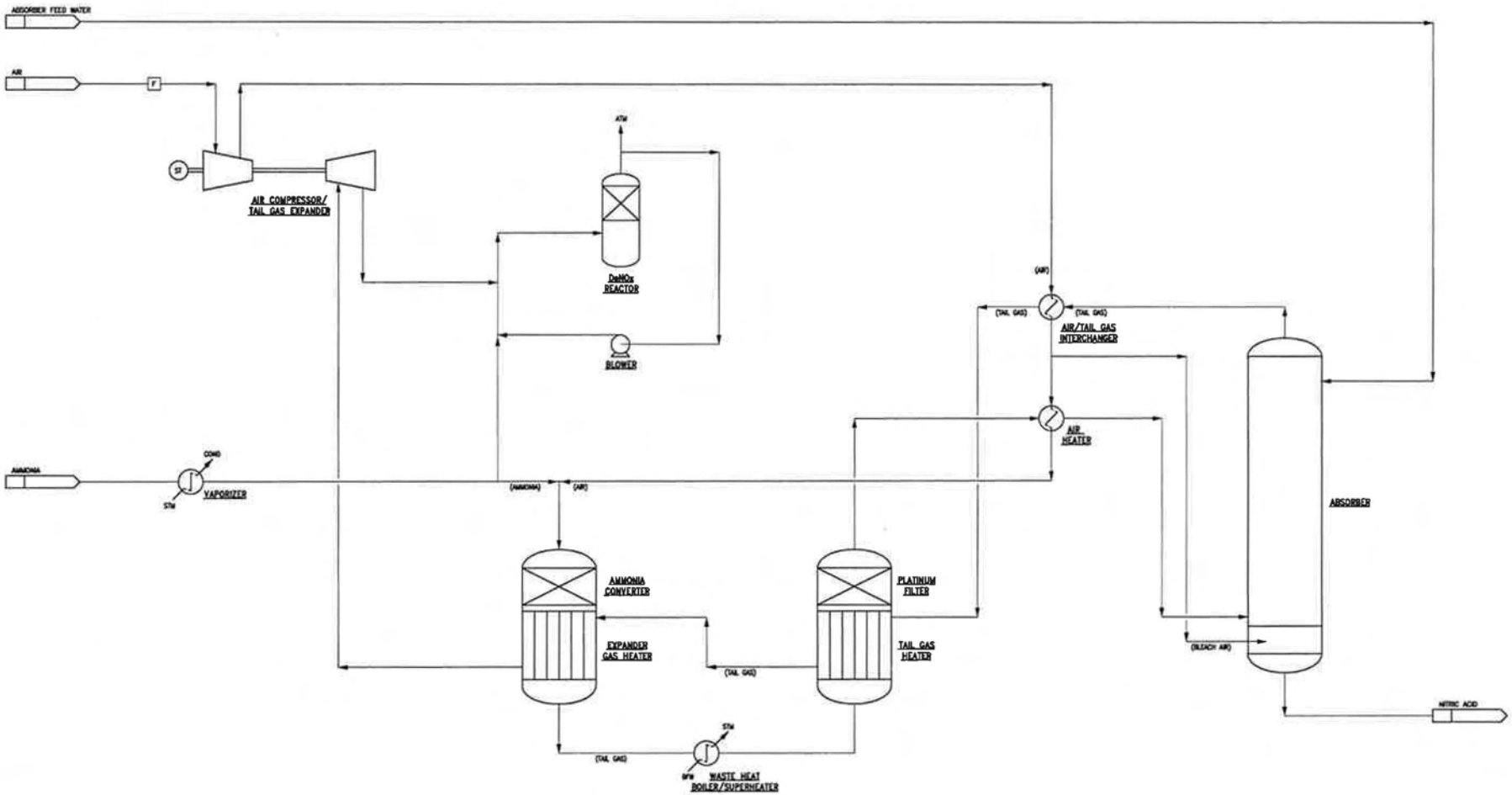
FIGURE 2-31



FLOW DIAGRAM
NITRIC ACID UNIT

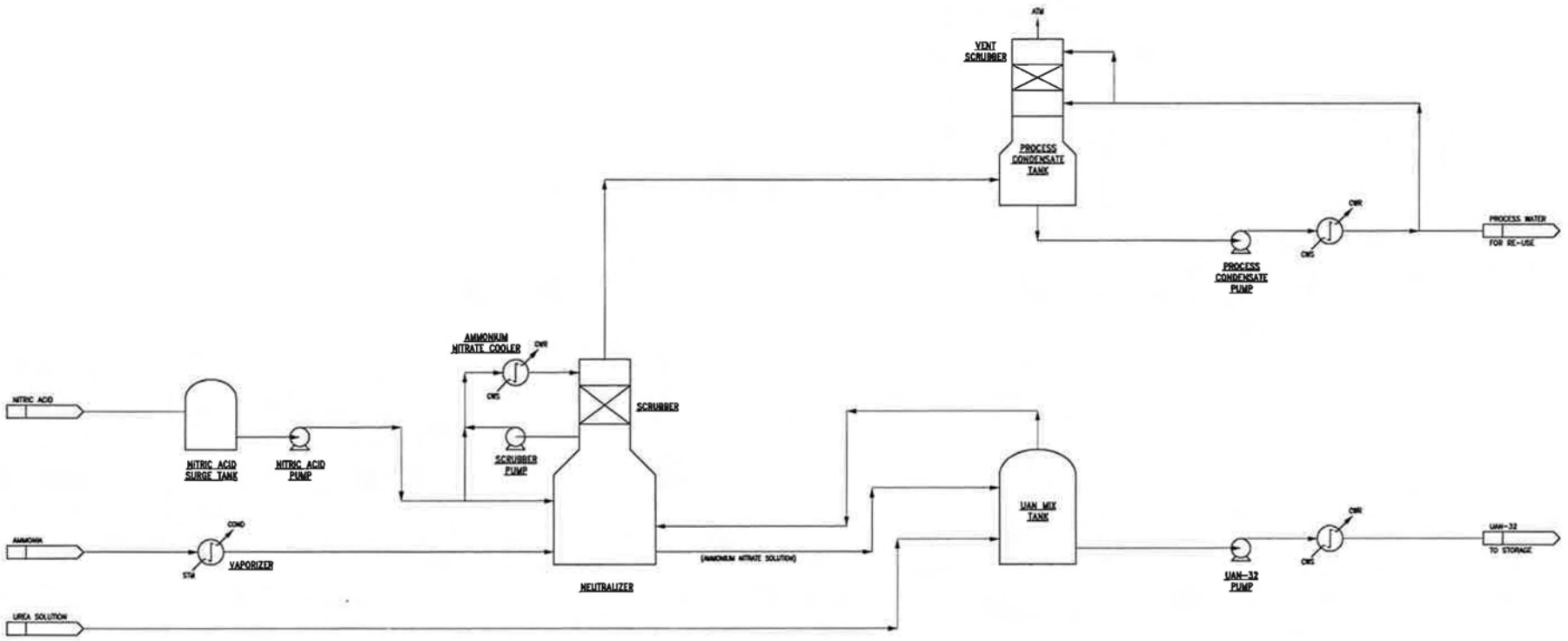
April 2012
28066052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-32

Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Nitric Acid Unit,
Drawing No: A4UV-080-25-SK-0004, Rev. 0 (2/14/12)



FLOW DIAGRAM
AMMONIUM NITRATE/UAN UNITS

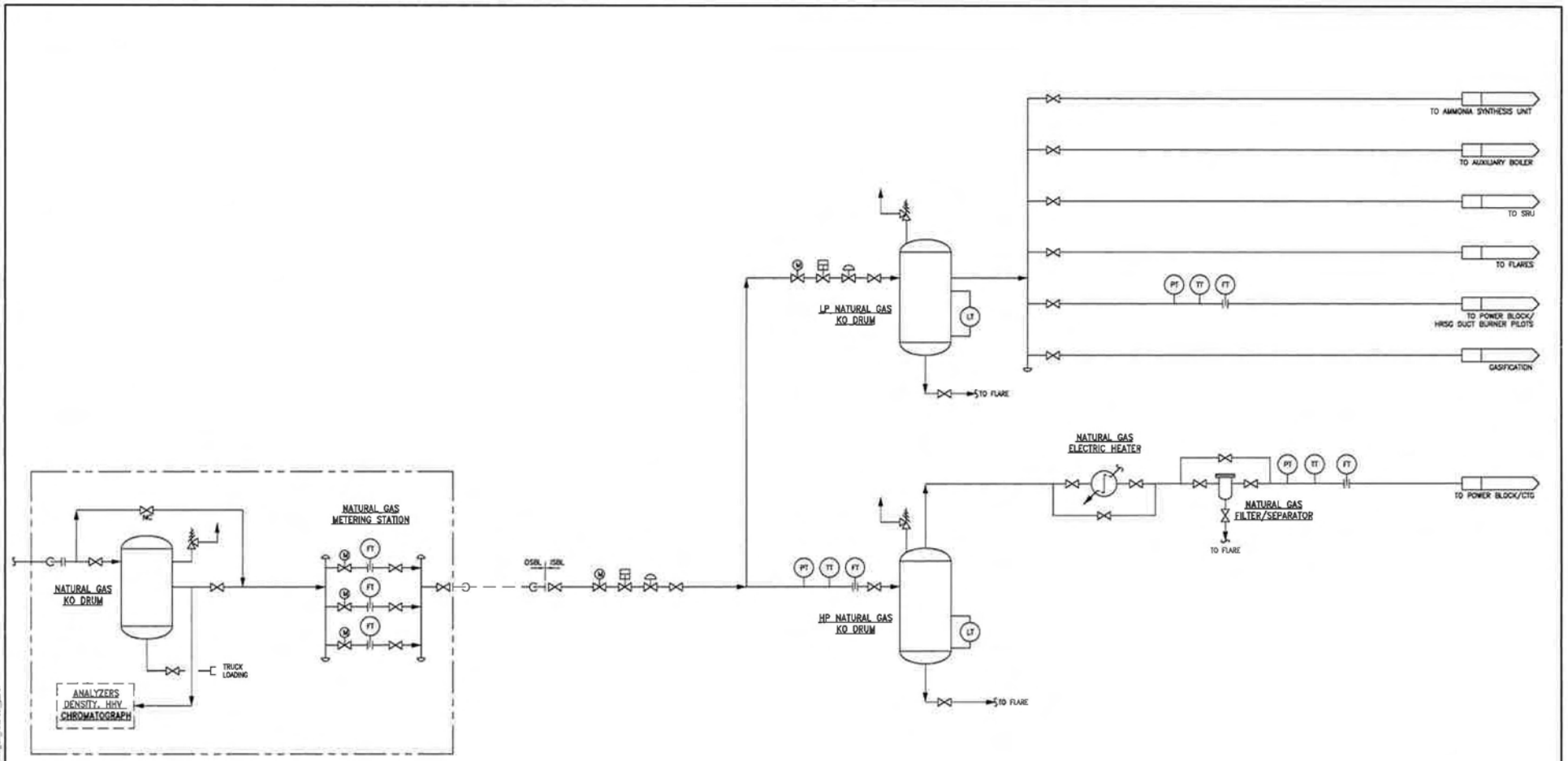
April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-33

Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Ammonium Nitrate/UAN Units.
Drawing No: A4UV-080-25-SK-0005, Rev. 0 (2/14/12)



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Natural Gas System;
Drawing No: A4UV-100-25-SK-0004, Rev. 1 (3/29/12)

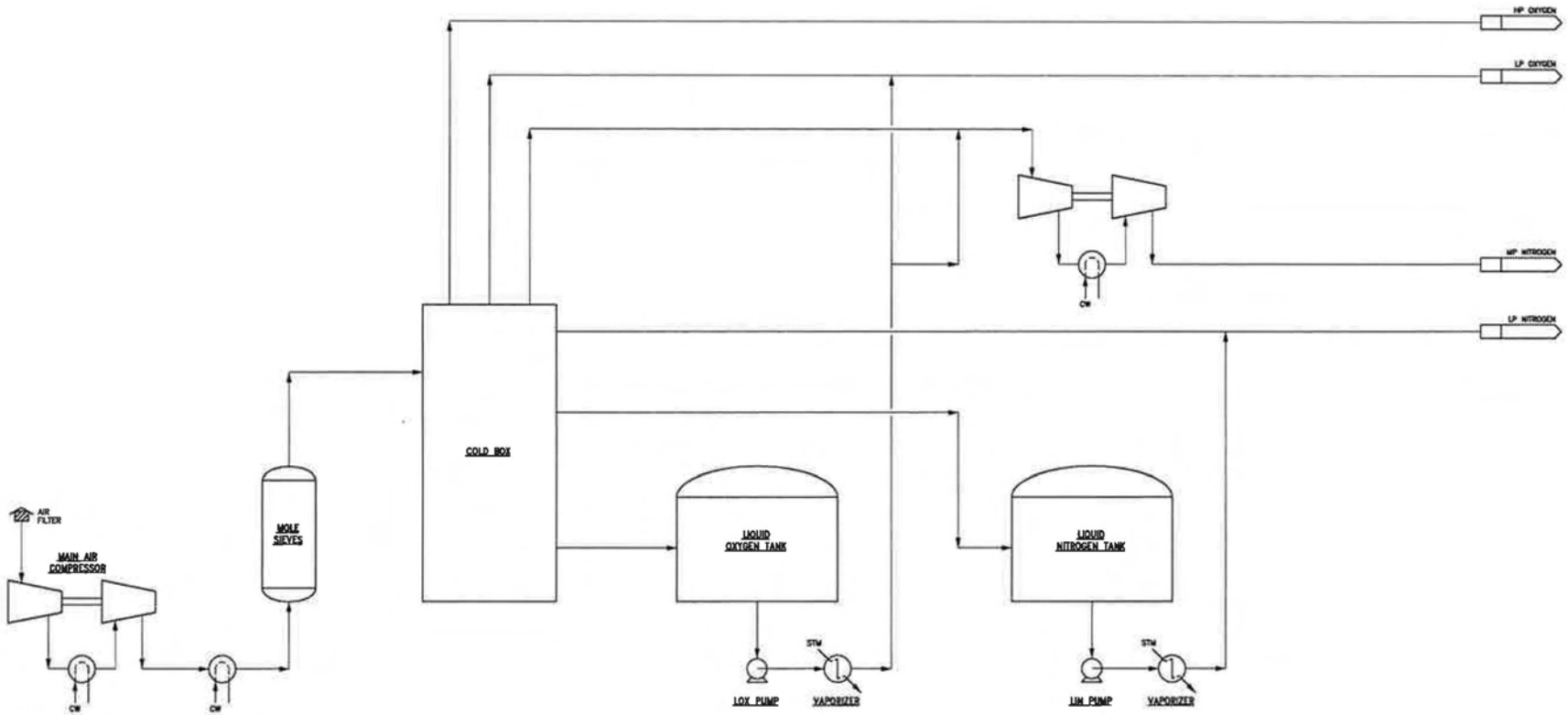
FLOW DIAGRAM
NATURAL GAS SYSTEM

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-34



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Air Separation Unit;
Drawing No: A4UV-150-25-SK-0001, Rev. 0 (2/14/12)

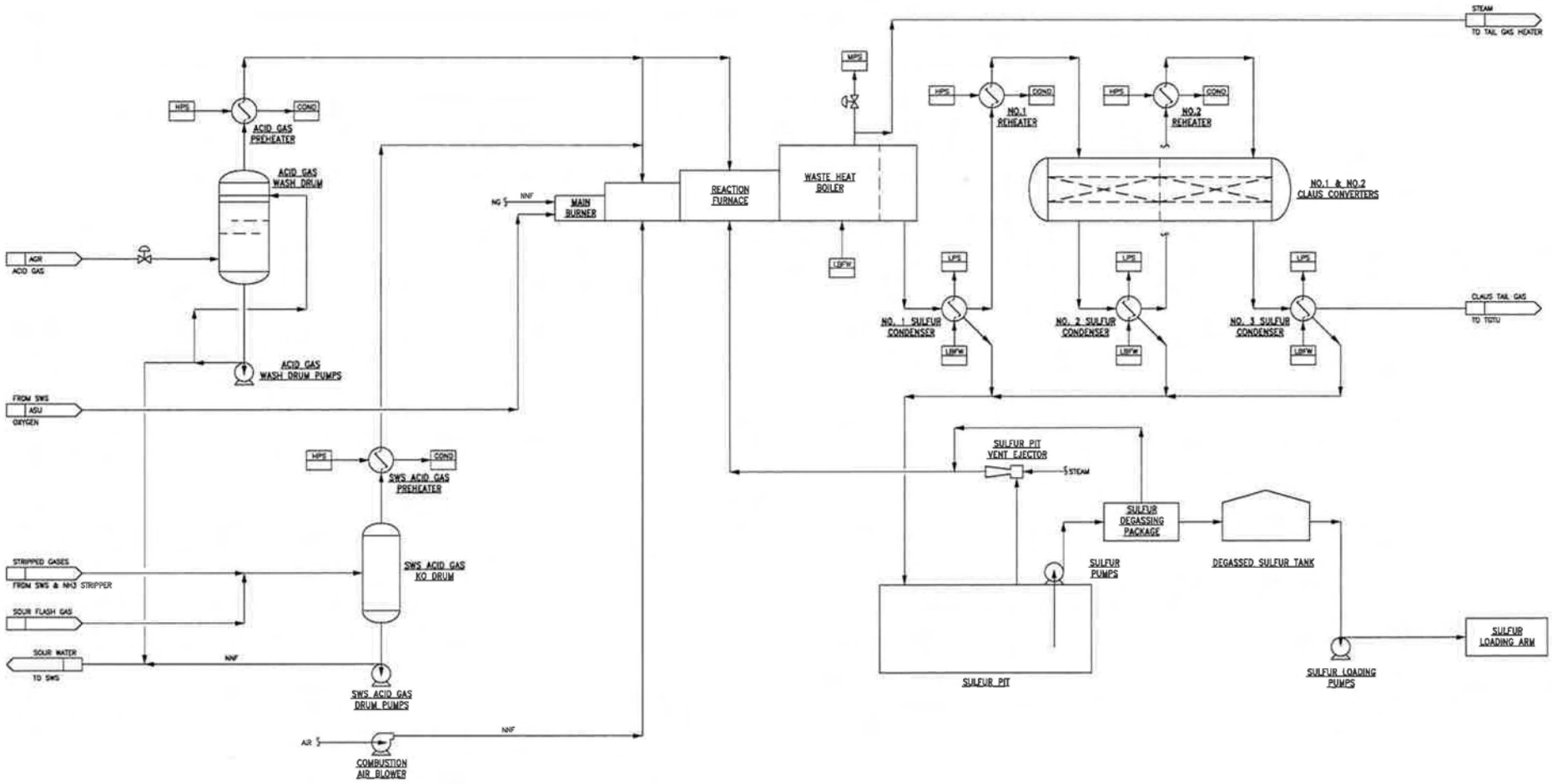
FLOW DIAGRAM
AIR SEPARATION UNIT

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-35



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Sulfur Recovery Unit;
Drawing No: A4UV-050-25-SK-0001, Rev. 1 (3/29/12)

FLOW DIAGRAM
SULFUR RECOVERY UNIT

April 2012
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Hydrogen Energy California (HECA)
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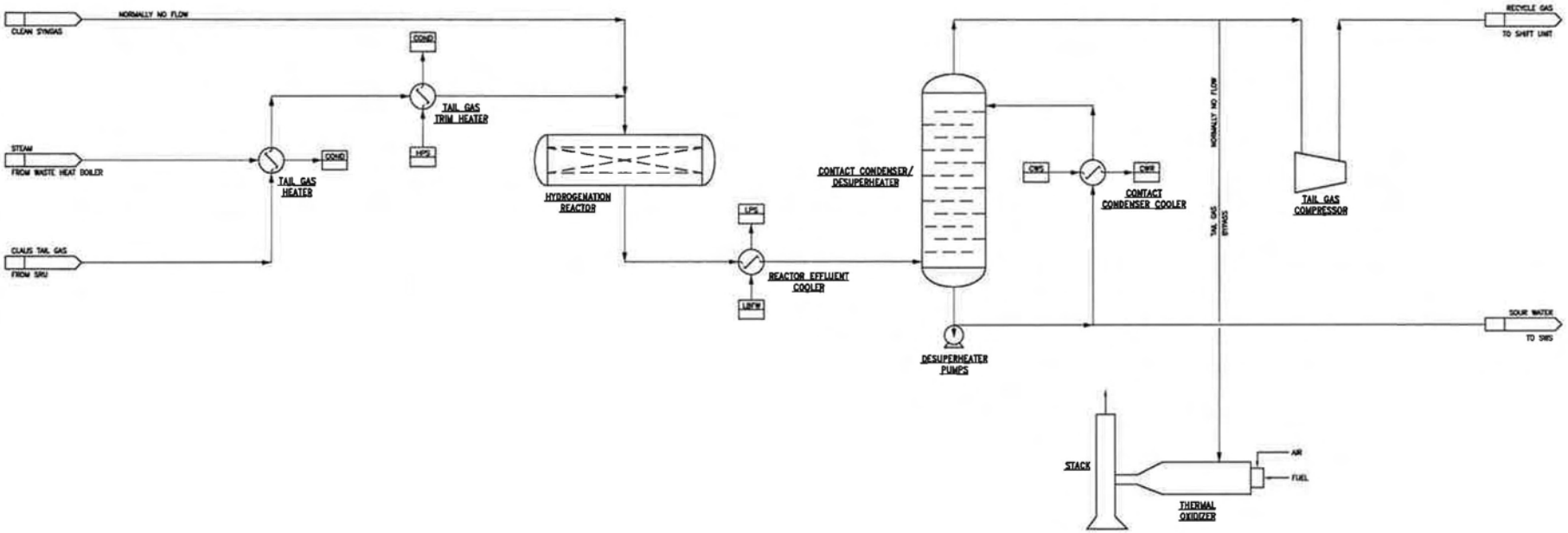
FIGURE 2-36



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Tail Gas Treating Unit,
Drawing No: A4UV-050-25-SK-0002, Rev. 0 (2/14/12)

FLOW DIAGRAM
TAIL GAS TREATING UNIT

April 2012
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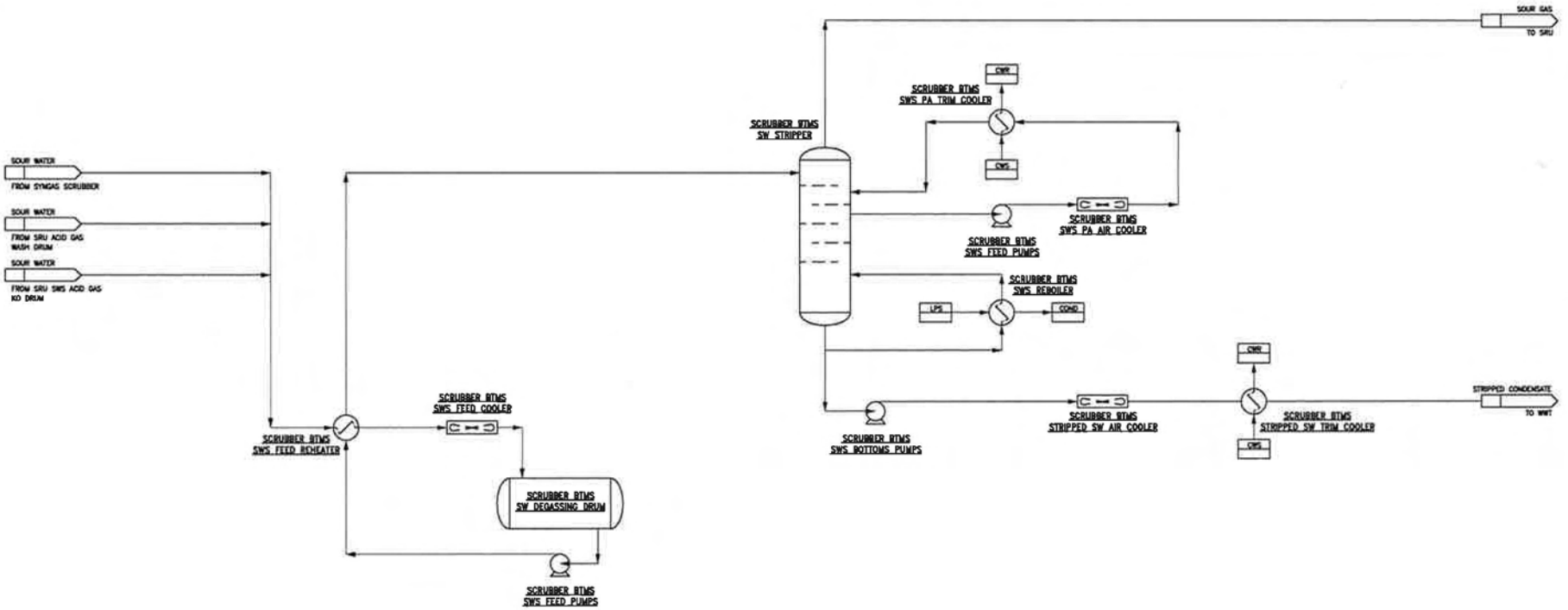
FIGURE 2-37



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Scrubber Bottoms Sour Water Stripper;
Drawing No: A4UV-020-25-SK-0004, Rev. 0 (2/14/12)

FLOW DIAGRAM
SCRUBBER BOTTOMS SOUR WATER STRIPPER

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

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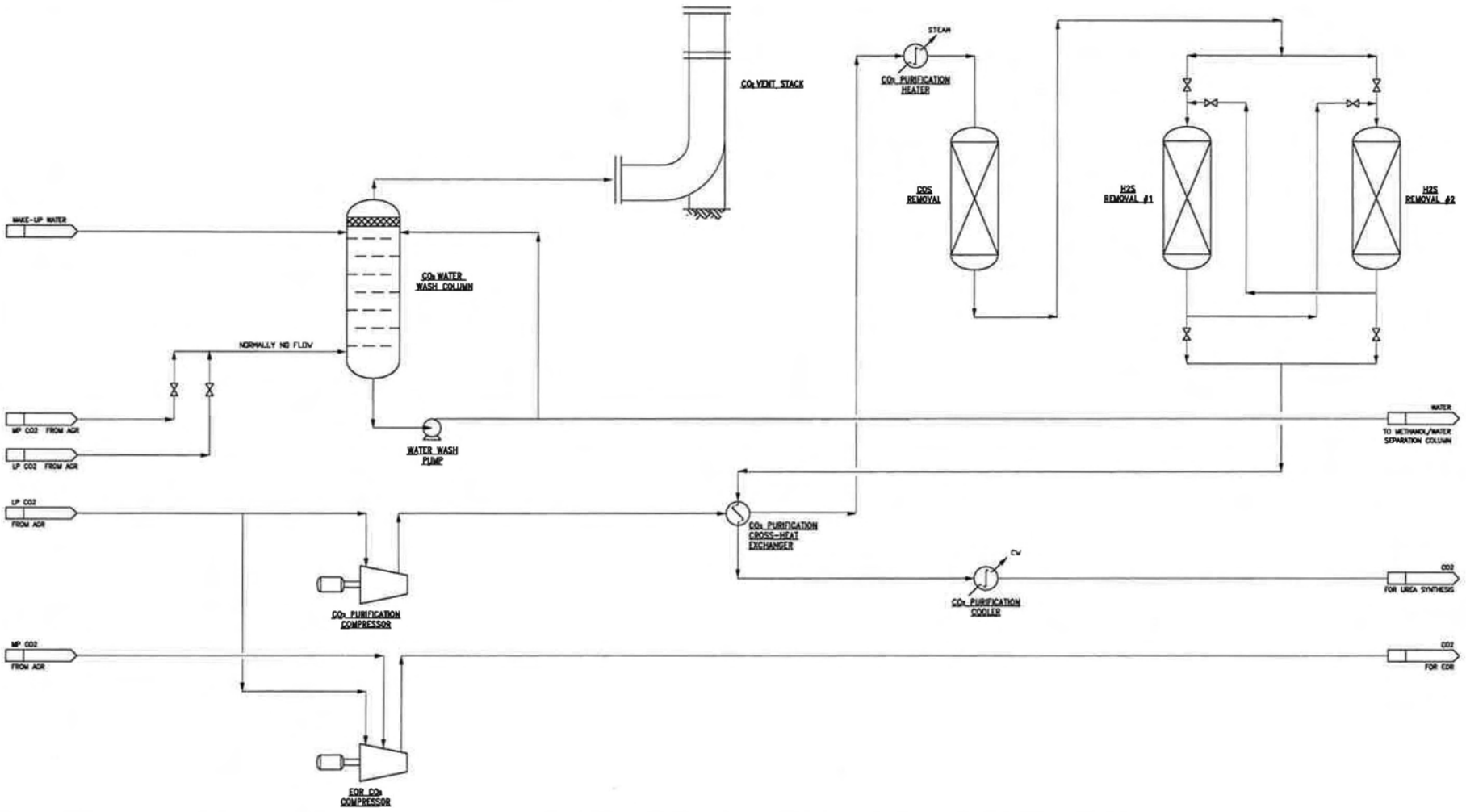
FIGURE 2-38



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram CO2 Compression and Purification Systems; Drawing No: A4UV-040-25-SK-0001, Rev. 0 (2/14/12)

FLOW DIAGRAM
CO_2 COMPRESSION AND PURIFICATION SYSTEMS

April 2012 — Hydrogen Energy California (HECA)
28068052 — Kern County, California

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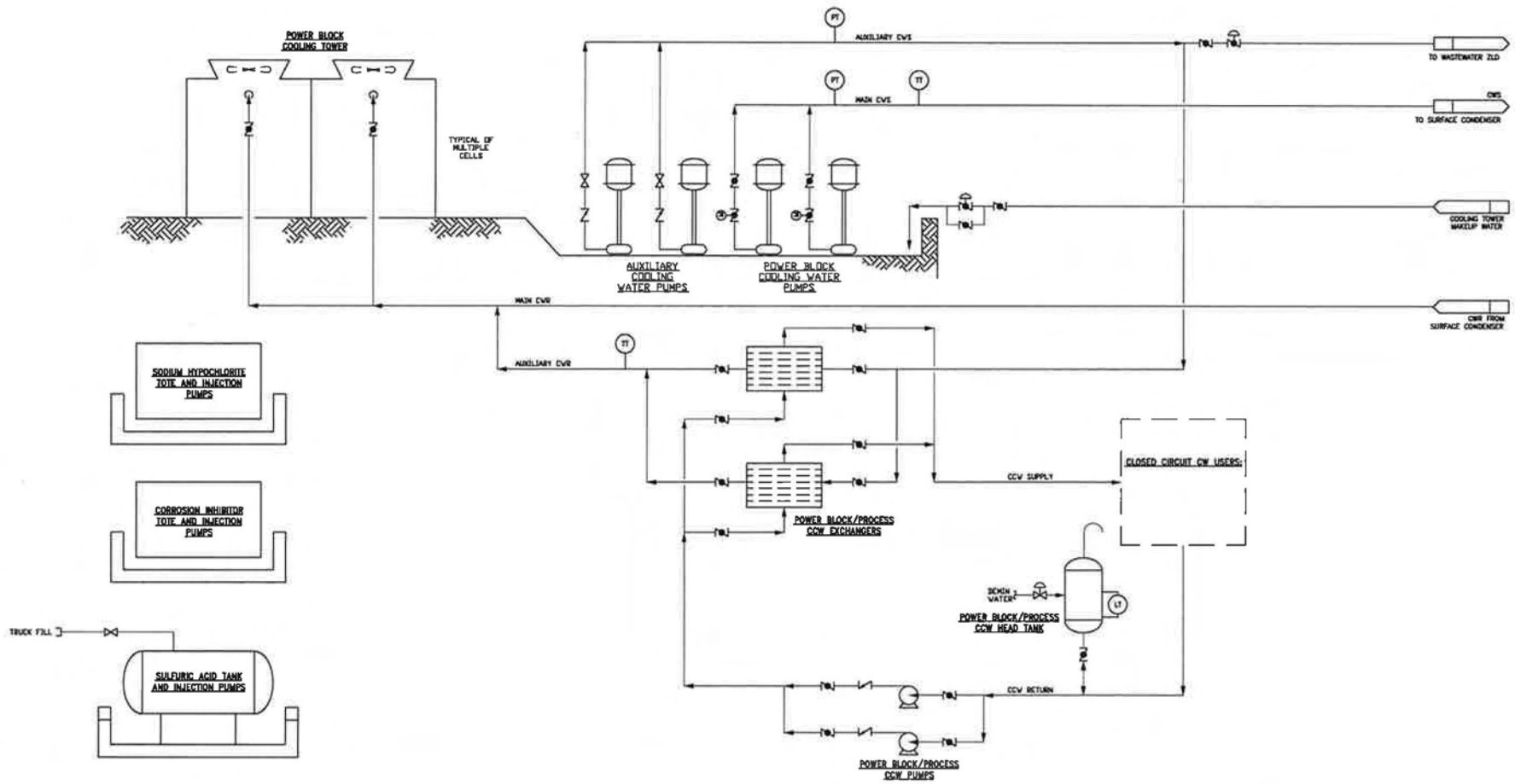
FIGURE 2-39



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Power Block Cooling Water System; Drawing No: A4UV-100-25-SK-0005, Rev, 0 (2/14/12)

FLOW DIAGRAM
POWER BLOCK COOLING WATER SYSTEM

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

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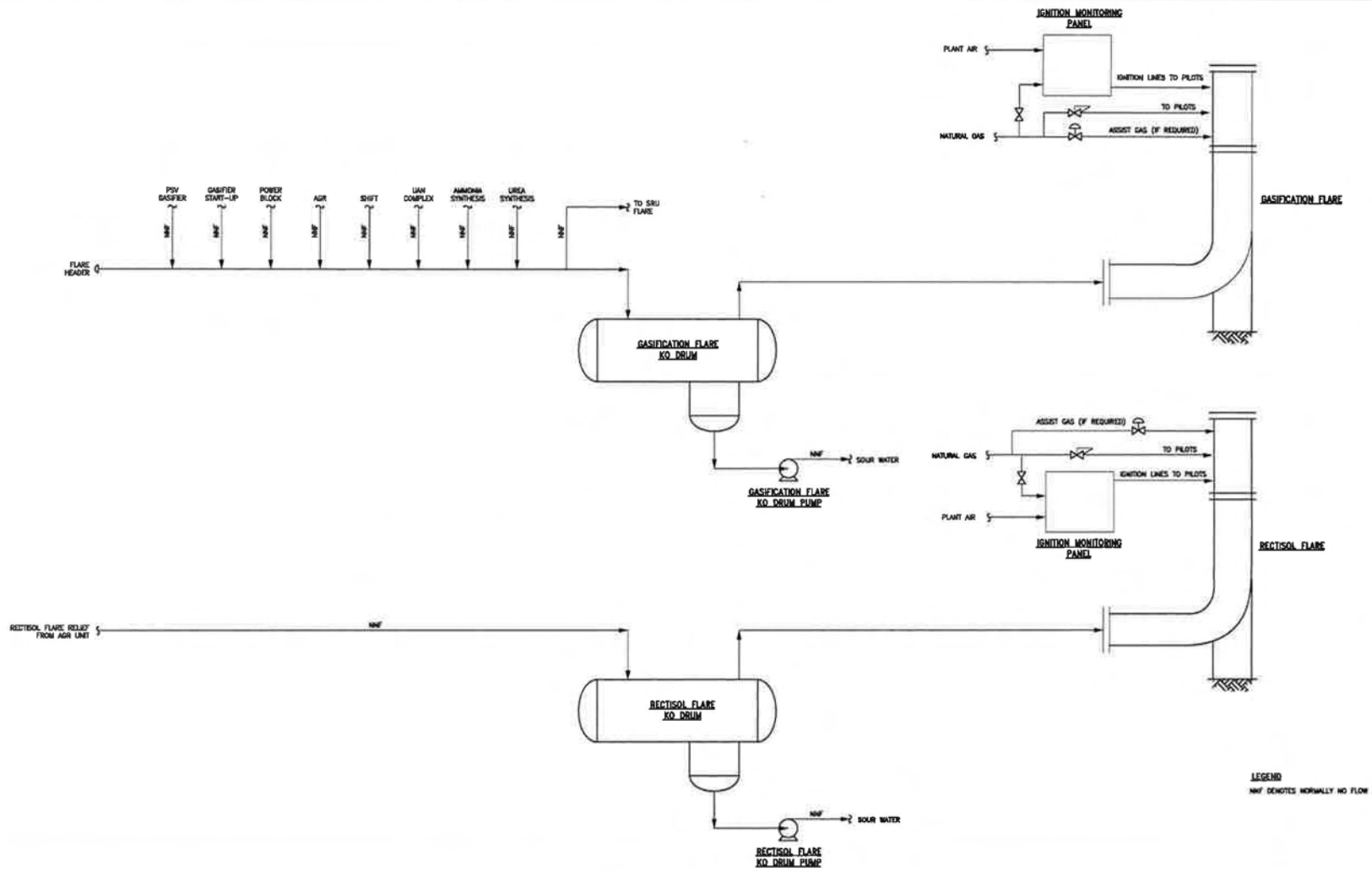
FIGURE 2-40



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Gasification and Rectisol Flare Systems; Drawing No: A4UV-100-25-SK-0001, Rev. 0 (2/14/12)

FLOW DIAGRAM
GASIFICATION AND RECTISOL FLARE SYSTEMS

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

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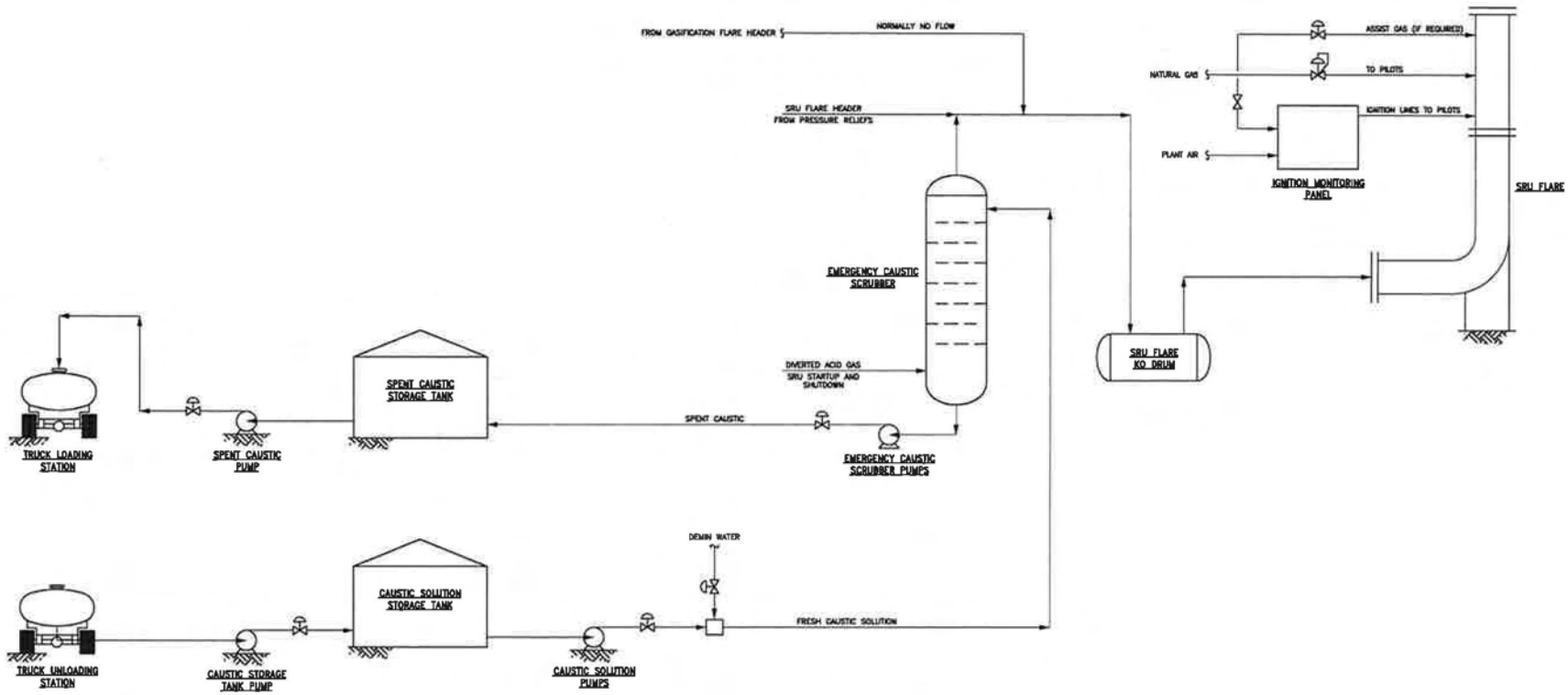
FIGURE 2-41



Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram SRU Flare System;
Drawing No: A4UV-100-25-SK-0002, Rev. 0 (2/14/12)

FLOW DIAGRAM
SRU FLARE SYSTEM

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

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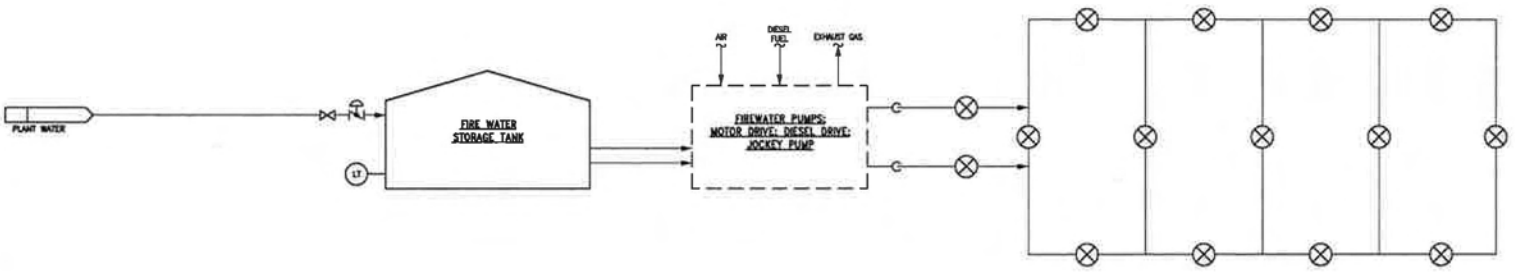
FIGURE 2-42

va_4/2012 \\GIS\HECA\Projects\ECA_2012\Illustrator_Files\2-42_flow_dia_SRU_flare.ai



BUILDING FIRE PROTECTION:

- CONTROL ROOM
- ADMINISTRATION
- WAREHOUSE/SHOP
- EMERGENCY RESPONSE & MEDICAL CENTER

FIRE WATER LOOP:

- FWs
- HOSE STATIONS
- MONITORS
- ACTIVATED VALVES

FIREWATER VALVE HOUSES

- POWER BLOCK COOLING TOWER
- GASIFICATION COOLING TOWER
- STG LUBE OIL & BEARINGS
- CTG MAIN TRANSFORMER
- ASU COOLING TOWER

Source:
Fluor; HECA-SCS, 2012 AFC Update; Flow Diagram Fire Water System:
Drawing No: A4UV-100-25-SK-0003, Rev. 0 (2/14/12)

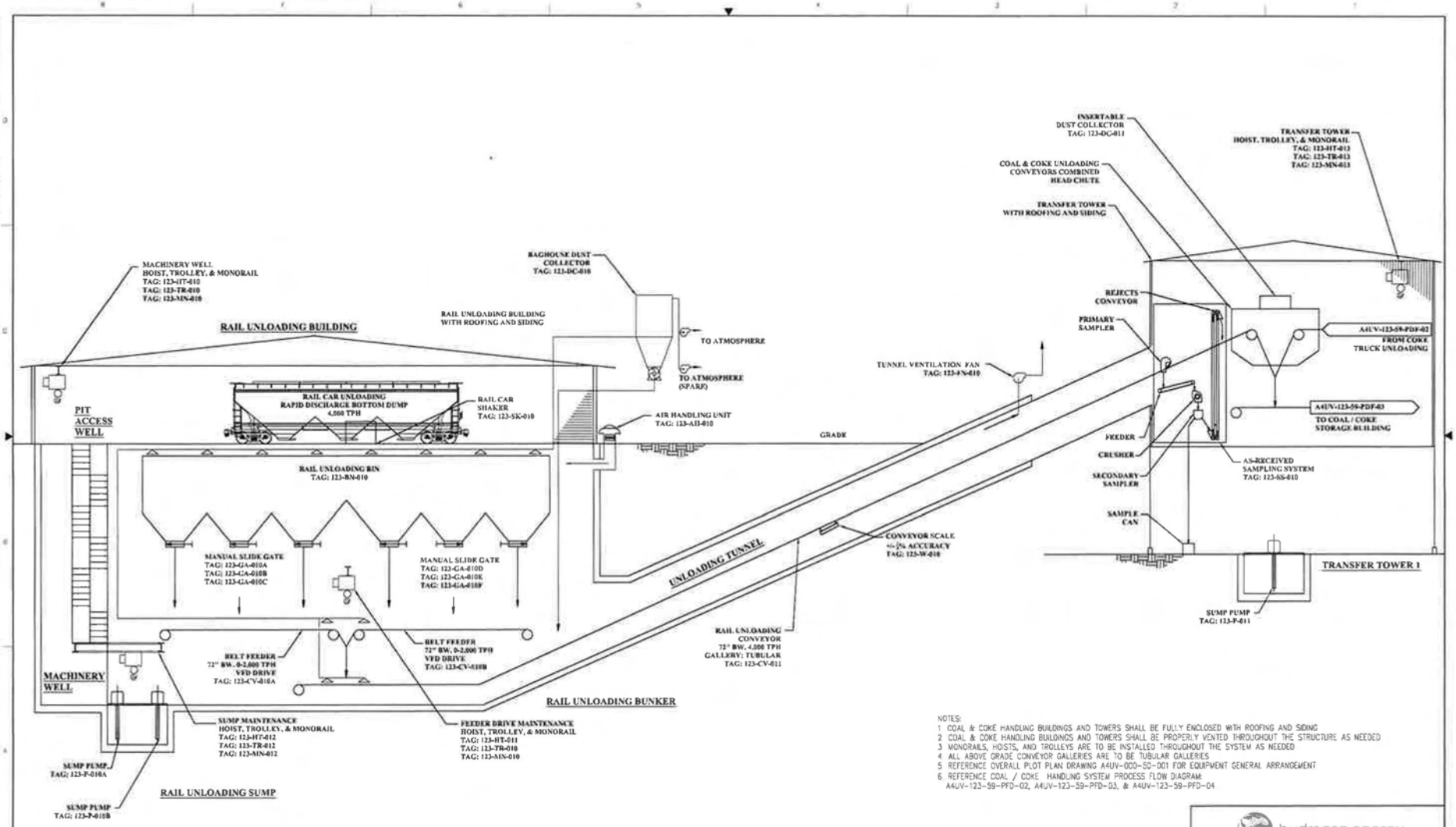
FLOW DIAGRAM
FIRE WATER SYSTEM

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-43



NOTES:
1. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE FULLY ENCLOSED WITH ROOFING AND SIDING
2. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED
3. MONORAILS, HOISTS, AND TROLLEYS ARE TO BE INSTALLED THROUGHOUT THE SYSTEM AS NEEDED
4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-50-001 FOR EQUIPMENT GENERAL ARRANGEMENT
6. REFERENCE COAL / COKE HANDLING SYSTEM PROCESS FLOW DIAGRAM: A4UV-123-59-PFD-02, A4UV-123-59-PFD-03, & A4UV-123-59-PFD-04

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DRAWING NUMBER	ACCEPTED DRAWINGS
A	3/30/2012	ISSUED FOR REVIEW	DK	GC	RDH								
B	6/29/2012	ISSUED FOR QUOTE	MC	JW	RDH								
C	9/28/2012	ISSUED FOR QUOTE	BL	JW	RDH								
D	12/12/2012	ISSUED FOR REVIEW	BL	JW	RDH								

FLUOR.

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CONTRACT	A4UV
DESIGNED BY	CAE
DRAWN BY	N/A
LEAD ENGINEER	N/A
ENGR WORK	CAE
CLIENT	N/A
APP. DATE	
APP. DATE	
APP. DATE	

hydrogen energy

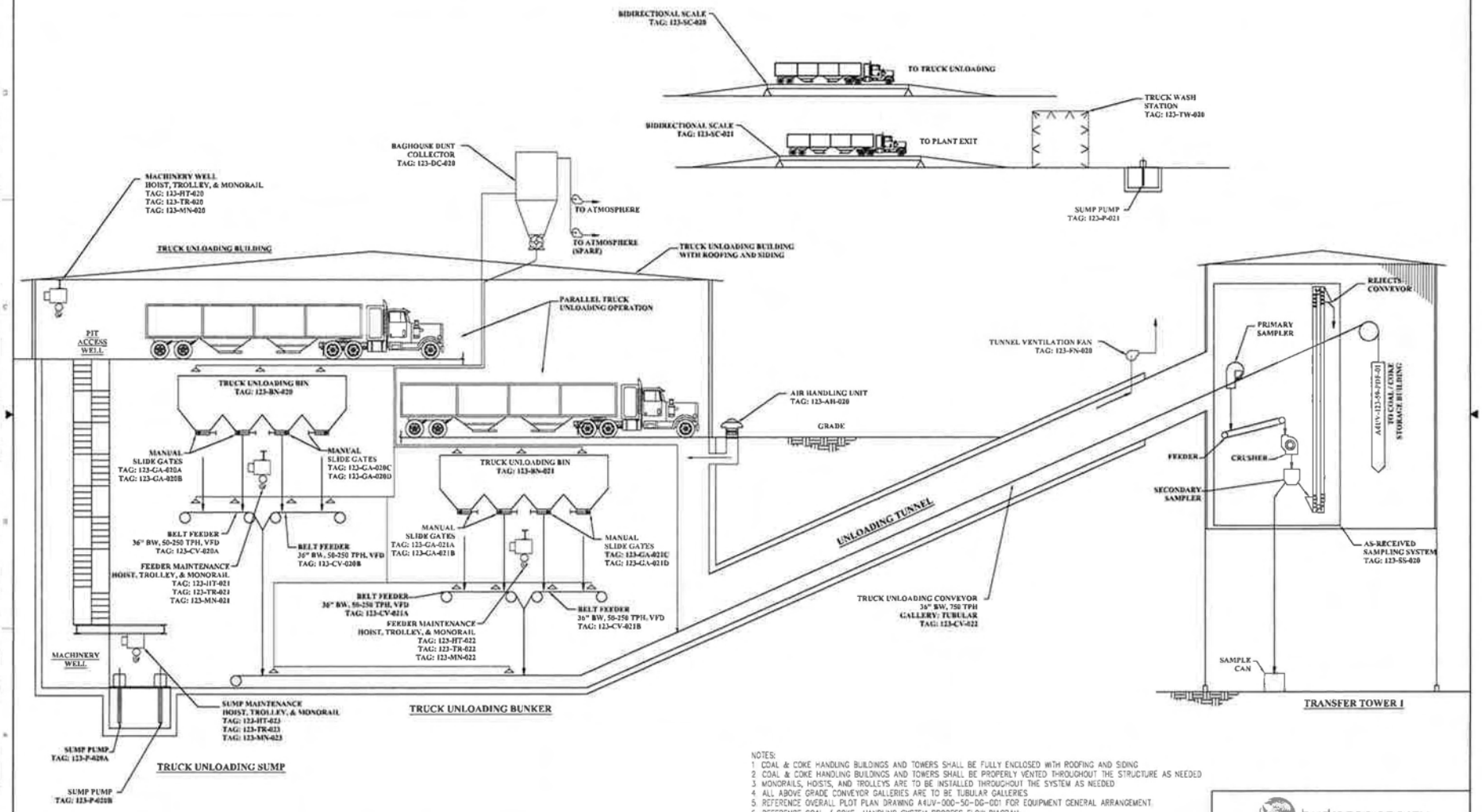
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COAL RAIL UNLOADING SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-123-59-PFD-01	0

CAD FILE NAME: A4UV-123-59-PFD-01_R0.DWG

PLOT DATE: 07-12-12 2:29 pm Printed By: eallen413 K:\200_MECHANICAL\336_ Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-123-59-PFD-01_R0.dwg



NOTES:
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2. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED
3. MONORAILS, HOISTS, AND TROLLEYS ARE TO BE INSTALLED THROUGHOUT THE SYSTEM AS NEEDED
4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-SC-DG-001 FOR EQUIPMENT GENERAL ARRANGEMENT.
6. REFERENCE COAL / COKE HANDLING SYSTEM PROCESS FLOW DIAGRAM A4UV-123-59-PFD-01, A4UV-123-59-PFD-03, & A4UV-123-59-PFD-04

REV	DATE	REVISION DESCRIPTION	BY	CHK	APVD	REV	DATE	REVISION DESCRIPTION	BY	CHK	APVD	MATERIAL ENG NUMBER	MATERIAL DRAWING
A	12/11/2012	ISSUED FOR REVIEW	LA	BE	RSH								
B	3/15/2013	ISSUED FOR QUOTE	MC	JW	RSH								
C	5/8/2013	ISSUED FOR QUOTE	BE	JW	RSH								
D	5/10/2013	ISSUED FOR REVIEW	BE	JW	RJM								

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CONTRACT	A4UV
DESIGNED BY	CA
DRAWN BY	BC
SUPERVISION	N/A
LEAD ENGINEER	APVD
CHECK BOX	C/S
CLIENT	N/A

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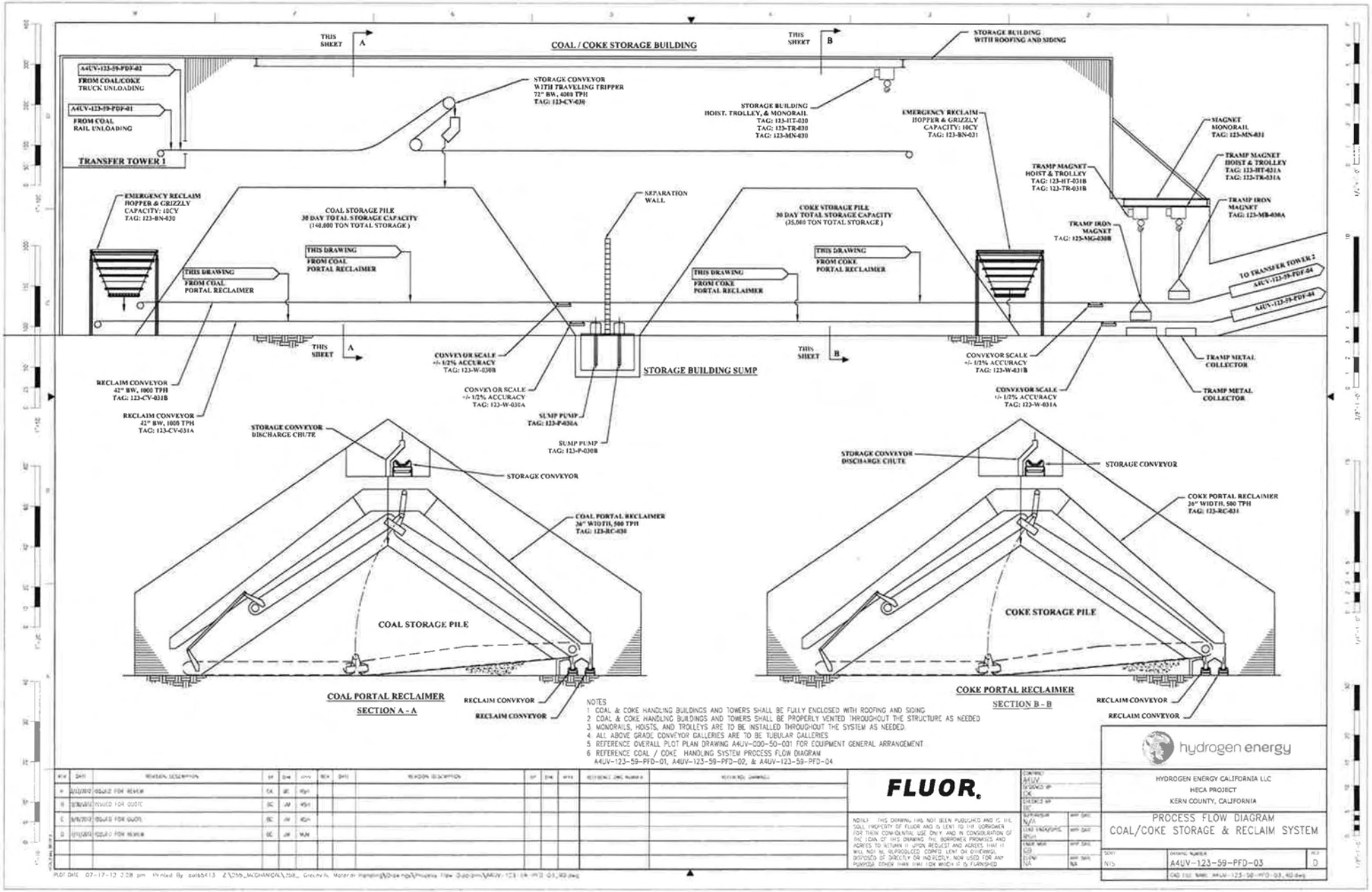
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COAL/COKE TRUCK UNLOADING SYSTEM

SCALE	DRAWING NUMBER	REV
N.T.S.	A4UV-123-59-PFD-02	D
	CAD FILE NAME: A4UV-123-59-PFD-02_R0.dwg	

PLOT DATE: 05-11-13 2:27 pm Printed by: pallbA13 X:\200_MECHANICAL\258_Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-123-59-PFD-02_R0.dwg



NOTES
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2. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED
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4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-50-001 FOR EQUIPMENT GENERAL ARRANGEMENT
6. REFERENCE COAL / COKE HANDLING SYSTEM PROCESS FLOW DIAGRAM A4UV-123-59-PFD-01, A4UV-123-59-PFD-02, & A4UV-123-59-PFD-04

REV	DATE	REVISION DESCRIPTION	BY	CHK	APVD	REV	DATE	REVISION DESCRIPTION	BY	CHK	APVD	REFERENCE DWG NUMBER	REVISION DWG NUMBER
A	3/12/2012	ISSUED FOR REVIEW	DK	BE	KSH								
B	3/26/2012	ISSUED FOR QUOTE	BE	JW	KSH								
C	3/9/2012	ISSUED FOR QUOTE	BE	JW	KSH								
D	07/12/2012	ISSUED FOR REVIEW	BE	JW	MM								

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CONTRACT	A4UV
ORIGINATOR	N/A
CHECKED BY	DK
SUPERVISOR	N/A
LEAD ENGINEER	N/A
PROJ ENG	BE
CQE	JW
PM	MM
QA	N/A

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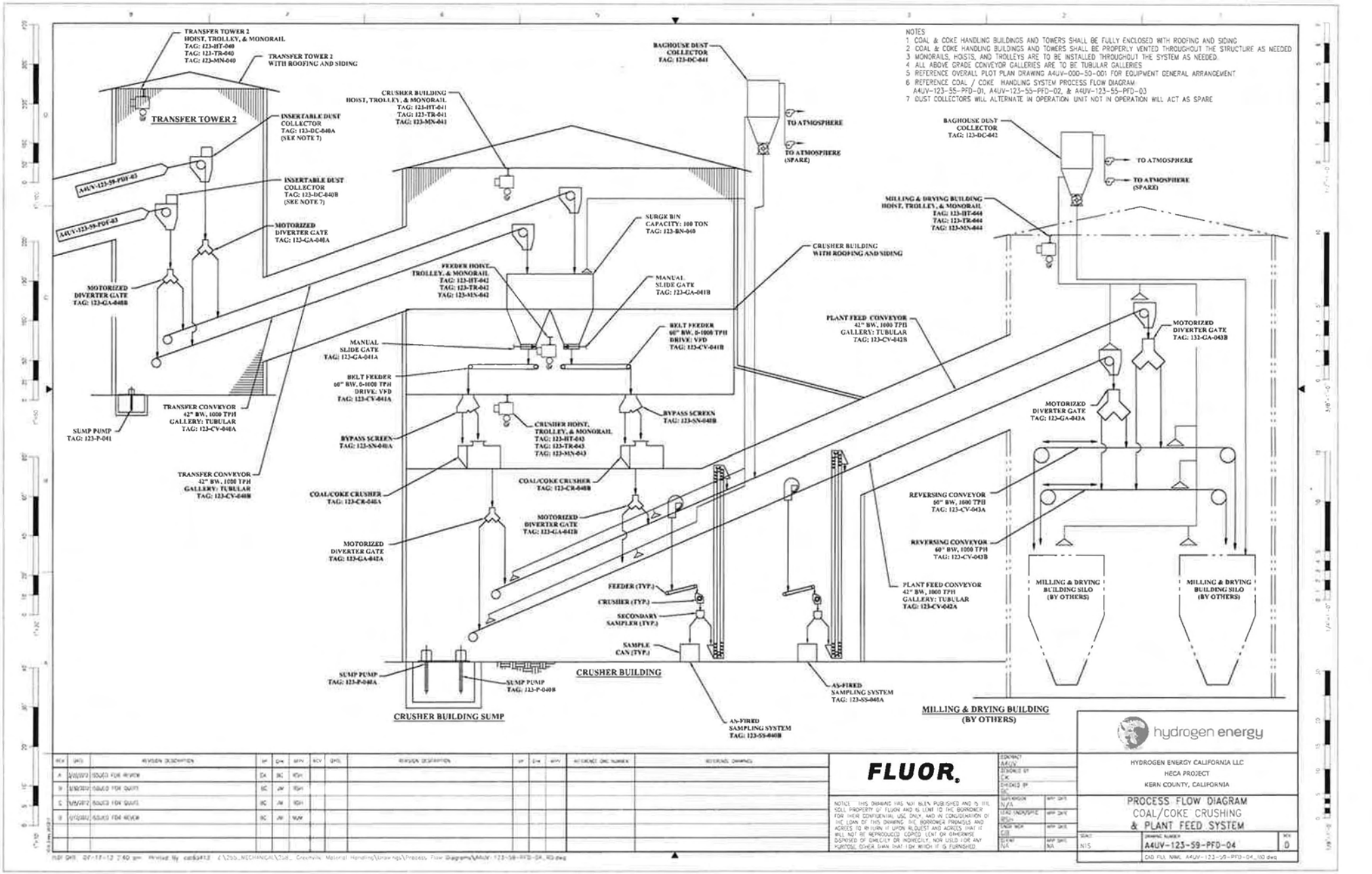
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM COAL/COKE STORAGE & RECLAIM SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-123-59-PFD-03	D

CAD FILE NAME: A4UV-123-59-PFD-03_4D.dwg

PLOT DATE: 07-17-12 2:28 pm Printed By: colb5413 Z:\05b_MECHANICAL\05B_ Graphics Material Handling\Draw ings\Process Flow Diagrams\A4UV-123-59-PFD-03_4D.dwg



NOTES
1. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE FULLY ENCLOSED WITH ROOFING AND SIDING
2. COAL & COKE HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED
3. MONORAILS, HOISTS, AND TROLLEYS ARE TO BE INSTALLED THROUGHOUT THE SYSTEM AS NEEDED.
4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-50-001 FOR EQUIPMENT GENERAL ARRANGEMENT
6. REFERENCE COAL / COKE HANDLING SYSTEM PROCESS FLOW DIAGRAM A4UV-123-55-PFD-01, A4UV-123-55-PFD-02, & A4UV-123-55-PFD-03
7. DUST COLLECTORS WILL ALTERNATE IN OPERATION. UNIT NOT IN OPERATION WILL ACT AS SPARE

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DRG NUMBER	REFERENCE DRAWING
A	2/6/2012	ISSUED FOR REVIEW	DA	BC	KSH								
B	3/8/2012	ISSUED FOR QUOTE	BC	JW	KSH								
C	7/5/2012	ISSUED FOR QUOTE	BC	JW	KSH								
D	9/7/2012	ISSUED FOR REVIEW	BC	JW	MJW								

FLUOR.

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CONTRACT	A4UV
DESIGNED BY	CJK
CHECKED BY	DC
SUPERVISION	N/A
LEAD DISCIPLINE	CJB
LEAD WORK	CJB
STAFF	N/A
APP. DATE	
APP. DATE	
APP. DATE	
APP. DATE	N/A

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HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

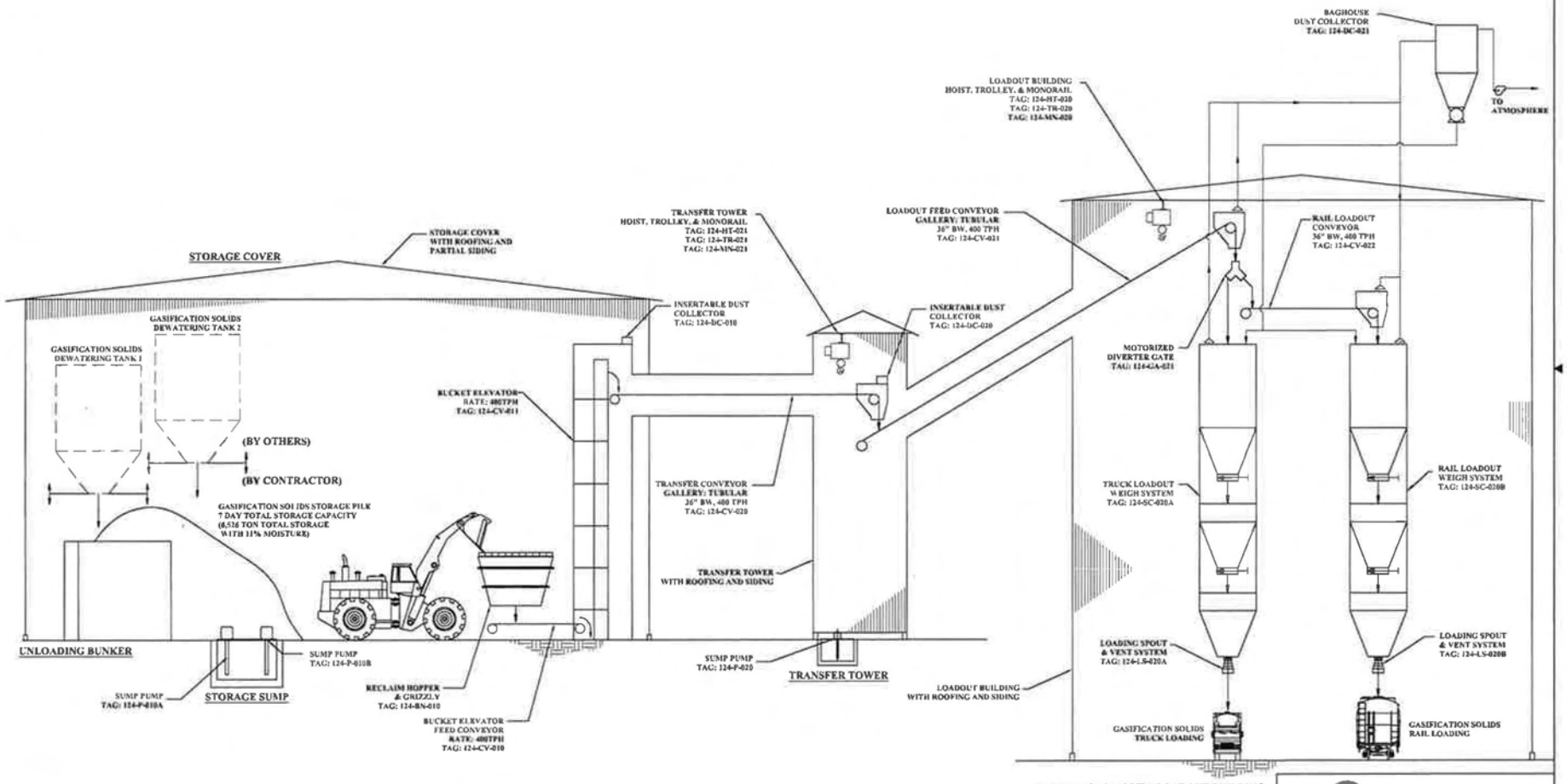
PROCESS FLOW DIAGRAM
COAL/COKE CRUSHING & PLANT FEED SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-123-59-PFD-04	D

CAD FILE NAME: A4UV-123-59-PFD-04_10.dwg

PLOT DATE: 09-18-12 2:40 pm Printed By: cardsh13 C:\Jobs_MECHANICAL\Job_ Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-123-59-PFD-04_10.dwg

NOTES:
1 BUILDINGS AND TOWER SHALL BE ENCLO"



GASIFICATION SOLIDS LOADOUT BUILDING

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV
A	2/22/2012	ISSUED FOR REVIEW	CK	BC	RSH
B	3/30/2012	ISSUED FOR QUOTE	BC	JW	RSH
C	5/8/2012	ISSUED FOR QUOTE	BC	JW	RSH
D	7/17/2012	ISSUED FOR REVIEW	BC	JW	MM

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DRG NUMBER	REFERENCE DRAWINGS

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CONTRACT	A4UV
DESIGNED BY	CK
CHECKED BY	BC
SUPERVISOR	N/A
LEAD ENGR/SPEC	RSH
CHEM ENGR	CB
CLIENT	NA
APP DATE	
APP DATE	
APP DATE	
APP DATE	NA

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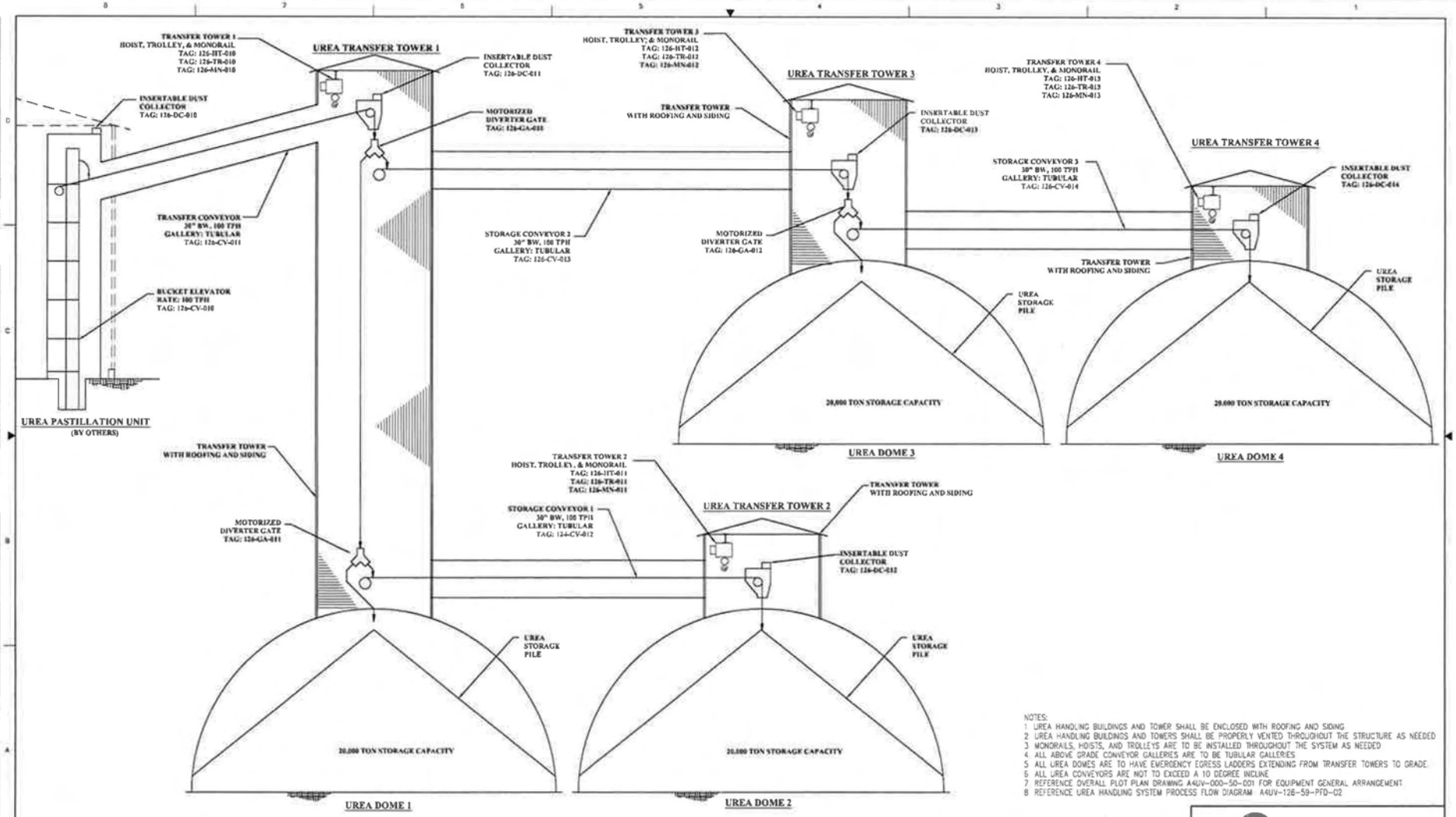
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM GASIFICATION SOLIDS MATERIAL HANDLING SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-124-59-PFD-01	D
	CAD FILE NAME: A4UV-124-59-PFD-01_RD.dwg	

PLOT DATE: 07-17-12 2:43 pm Printed By: col65413 Z:\256_MECHANICAL\256_ Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-124-59-PFD-01_RD.dwg



NOTES:
1. UREA HANDLING BUILDINGS AND TOWER SHALL BE ENCLOSED WITH ROOFING AND SIDING.
2. UREA HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED
3. MONORAILS, HOISTS, AND TROLLEYS ARE TO BE INSTALLED THROUGHOUT THE SYSTEM AS NEEDED
4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. ALL UREA DOMES ARE TO HAVE EMERGENCY EGRESS LADDERS EXTENDING FROM TRANSFER TOWERS TO GRADE.
6. ALL UREA CONVEYORS ARE NOT TO EXCEED A 10 DEGREE INCLINE
7. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-50-001 FOR EQUIPMENT GENERAL ARRANGEMENT
8. REFERENCE UREA HANDLING SYSTEM PROCESS FLOW DIAGRAM A4UV-126-59-PFD-02

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV
A	2/22/2012	ISSUED FOR REVIEW	CK	BC	RSH
B	3/30/2012	ISSUED FOR QUOTE	BC	JW	RSH
C	5/8/2012	ISSUED FOR QUOTE	BC	JW	RSH
D	7/17/2012	ISSUED FOR REVIEW	BC	JW	MJH

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS

FLUOR

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CONTRACT	A4UV
DESIGNED BY	CK
CHECKED BY	BC
SUPERVISOR	N/A
LEAD ENGR/SPEC.	RSH
ENGR MGR	GB
FLUENT	NA

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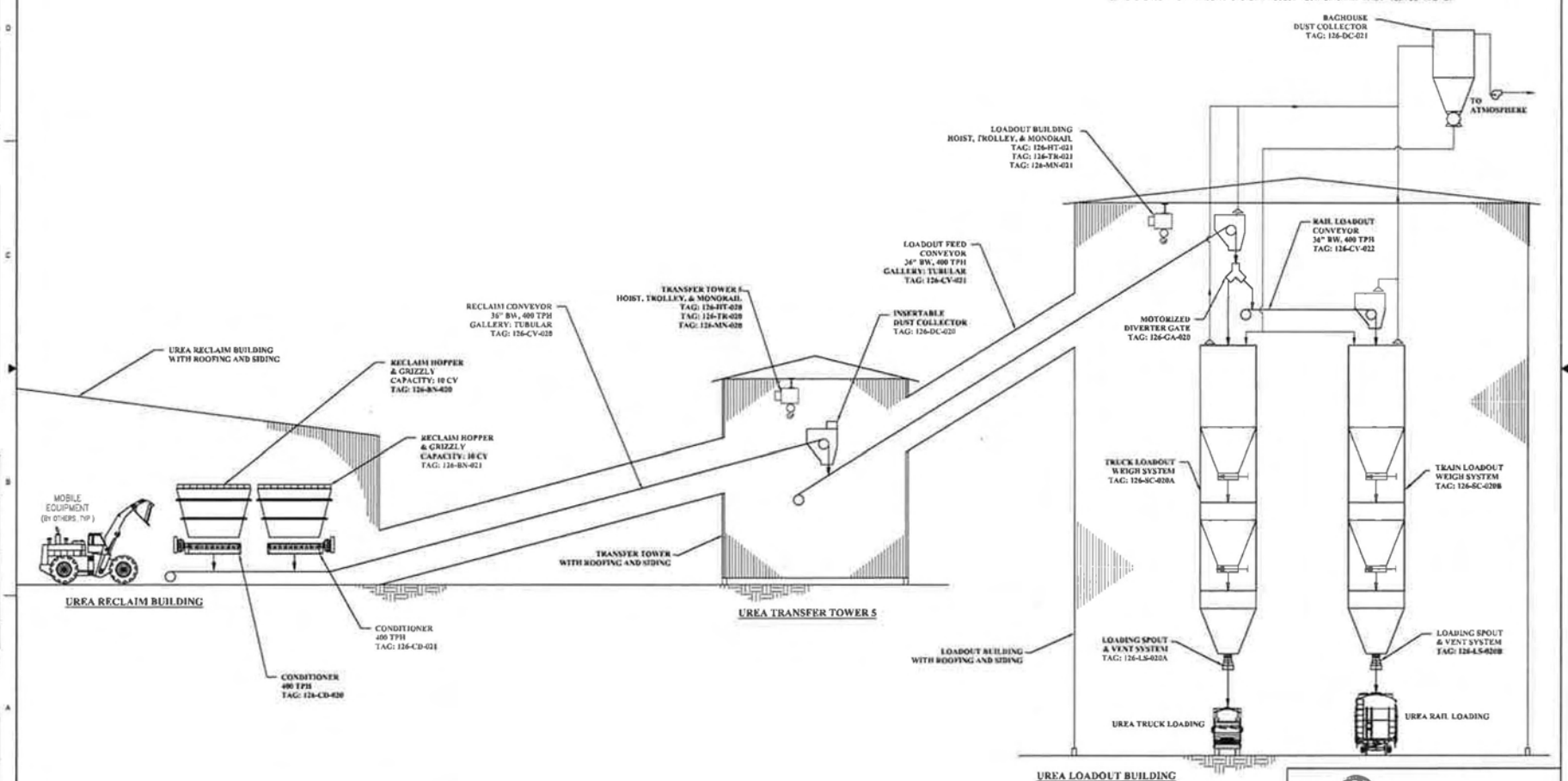
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
UREA TRANSFER & STORAGE SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-126-59-PFD-01	D
	CAD FILE NAME: A4UV-126-59-PFD-01_RD.dwg	

PLOT DATE: 07-17-12 2:46 pm Printed By: cat85413 Z:\355_MECHANICAL\355_ Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-126-59-PFD-01_RD.dwg

NOTES:
1. UREA HANDLING BUILDINGS AND TOWER SHALL BE ENCLOSED WITH ROOFING AND SIDING
2. UREA HANDLING BUILDINGS AND TOWERS SHALL BE PROPERLY VENTED THROUGHOUT THE STRUCTURE AS NEEDED.
3. MONORAILS, HOISTS, AND TROLLEYS ARE TO BE INSTALLED THROUGHOUT THE SYSTEM AS NEEDED
4. ALL ABOVE GRADE CONVEYOR GALLERIES ARE TO BE TUBULAR GALLERIES
5. ALL UREA CONVEYORS ARE NOT TO EXCEED A 10 DEGREE INCLINE
6. REFERENCE OVERALL PLOT PLAN DRAWING A4UV-000-50-001 FOR EQUIPMENT GENERAL ARRANGEMENT
7. REFERENCE UREA HANDLING SYSTEM PROCESS FLOW DIAGRAM: A4UV-126-59-PFD-01.



REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV
A	2/01/2012	ISSUED FOR REVIEW	CK	BC	RSH
B	4/04/2012	ISSUED FOR QUOTE	BC	AM	RSH

FLUOR.

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CONTRACT	A4UV
DESIGNED BY	CK
CHECKED BY	BC
SUPERVISOR	N/A
LEAD ENGR/SPLST	RSH
ENGR MGR	RSH
QB	RSH
CLIENT	N/A

hydrogen energy

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM UREA RECLAIM & LOADOUT SYSTEM

SCALE	DRAWING NUMBER	REV
NTS	A4UV-126-59-PFD-02	B
	CAD FILE NAME: A4UV-126-59-PFD-02_RB.dwg	

PLOT DATE: 04-02-12 8:55 am Printed By: cat53413 Z:\253_MECHANICAL\258_ Greenville Material Handling\Drawings\Process Flow Diagrams\A4UV-126-59-PFD-02_RB.dwg

APPENDIX E
Fugitive Emission Calculations

HECA - Total VOC Content of the Gas in Each Process Area	Process Area																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	18a	18b	19	20	21	22	23
	Methanol	Syn Gas		Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	SRU Tail Gas	Low NH3 Concen-tration	Moderate NH3 Concen-tration	High NH3 Concen-tration	Low CO2 Concen-tration	Moderate CO2 Concen-tration	High CO2 Concen-tration	CO2 Product and Purification Compressors	Urea CO2 Compressor	NO2	HNO3	PSA Off Gas	Lower Benzene Concentration	Higher Benzene Concentration
Total weight percentage of VOC in the gas in each process area	**99.74%**	**0.25%**	**0.00%**	**0.01%**	**100.00%**	**0.08%**	**79.07%**	**72.36%**	**4.23%**	**2.13%**	**0.00%**	**0.29%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.41%**	**0.04%**	**0.00%**	**0.00%**	**0.00%**	**0.03%**	**47.10%**	**91.90%**

Note: The following compounds are included as VOCs, although not all compounds are found in the gas in each process area: CH3OH, C3H6, COS, and HCN.

Compound	Wt %																							
	Methanol Stream	Syn Gas		Shifted Syn Gas Stream	Propylene Stream	Sour Water Stream	H_2S Laden Methanol Stream	CO_2 Laden Methanol Stream	Acid Gas Stream	Ammonia-Laden Gas Stream	Sulfur Stream	SRU Tail Gas	Low NH3 Concen-tration	Moderate NH3 Concen-tration	High NH3 Concen-tration	Low CO2 Concen-tration	Moderate CO2 Concen-tration	High CO2 Concen-tration	CO2 Product and Purification Compressors	Urea CO2 Compressor	NO2	HNO3	PSA Off Gas	Lower Benzene Concentration	Higher Benzene Concentration
Carbon dioxide (CO2)	0.00%	8.02%		59.90%	0.00%	1.98%	15.64%	27.34%	49.76%	60.57%	0.00%	65.26%	5.77%	37.53%	0.76%	18.90%	37.53%	97.76%	97.76%	100.00%	0.00%	0.00%	14.72%	47.80%	7.30%
Carbon monoxide (CO)	0.00%	43.27%		2.97%	0.00%	0.007%	0.01%	0.01%	2.05%	0.22%	0.00%	2.46%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%	8.58%	0.00%	0.00%
Methane (CH4)	0.00%	0.59%		0.60%	0.00%	0.00%	0.005%	0.013%	0.002%	0.009%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%	3.10%	0.00%	0.00%
Hydrogen Sulfide (H2S)	0.00%	0.58%		0.62%	0.00%	0.05%	0.92%	0.0001%	28.46%	1.35%	0.02%	1.99%	0.00%	0.00%	0.00%	0.00%	0.00%	1.56%	0.00%	0.00%	0.00%	0.00%	0.00%	4.20%	0.80%
Ammonia (NH3)	0.00%	0.14%		0.11%	0.00%	0.70%	0.00%	0.00%	0.00%	20.15%	0.00%	0.00%	15.59%	49.17%	97.98%	31.31%	49.17%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sulfur dioxide (SO2)	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	3.12%	0.00%	0.00%	0.38%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hydrogen Chloride (HCl)	0.00%	0.00%		0.00%	0.00%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nitric acid (HNO3)	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	56.22%	0.00%	0.02%	0.02%
Nitrogen dioxide (NO2)	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.28%	0.00%	0.00%	0.02%	0.02%
Other (Inerts)	0.26%	47.15%		35.81%	0.00%	97.14%	4.35%	0.27%	12.39%	15.58%	99.98%	29.62%	78.61%	13.30%	1.26%	49.74%	13.30%	0.26%	2.14%	0.00%	92.71%	43.78%	73.58%	0.90%	0.00%
Carbonyl Sulfide (COS)	0.00%	0.24%		0.004%	0.00%	0.08%	0.00%	0.00%	2.71%	2.09%	0.00%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Methanol (CH3OH)	99.74%	0.00%		0.001%	0.00%	0.00%	79.06%	72.36%	1.51%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.40%	0.03%	0.00%	0.00%	0.00%	0.03%	46.30%	86.80%
Propylene (C3H6)	0.00%	0.00%		0.000%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Benzene (C6H6)	0.00%	0.00%		0.000%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.80%	5.10%
Hydrogen Cyanide (HCN)	0.00%	0.01%		0.000%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.98%	100.00%	100.00%	99.96%	100.00%	100.00%	99.96%	100.00%	100.00%	100.00%	100.00%	100.03%	100.03%
Percentage of VOC of the entire gas stream *	99.74%	0.25%	0.00%	0.01%	100.00%	0.08%	79.07%	72.36%	4.23%	2.13%	0.00%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.41%	0.04%	0.00%	0.00%	0.00%	0.03%	47.10%	91.90%

* Per District policy (SSP-2015), VOC emissions are not assessed to components handling fluid streams with a VOC content of 10% of less by weight.

Equipment Type	Service	Emission Factor ** (kg/hr/source)		Emission Factor (lb/hr/source)		Control Efficiency ***
Valves	Gas	0.00597		0.0132		92%
Valves	Light liquid	0.00403		0.0089		88%
Valves	Heavy liquid	0.00023		0.0005		0%
Pump seals	Light liquid	0.0199		0.0439		100%
Pump seals	Heavy liquid	0.00862		0.0190		0%
Compressor seals	Gas	0.228		0.5027		100%
Pressure relief valves	Gas	0.104		0.2293		0%
Connectors	All	0.00183		0.0040		93%
Open-ended lines	All	0.0017		0.0037		0%
Sampling connectors	All	0.015		0.0331		0%

** Notes:
** Emission factors and control efficiencies are from EPA's 1995 "Protocol for Equipment Leak Emission Estimates".
** Emission factors are from Table 2-1 (SOCMI Average Emission Factors)
*** Control efficiencies are from Tables 5-1 and 5-2 (Control Effectiveness for an LDAR Program at a SOCMI Process Unit)
*** The permittee proposes to implement an LDAR program for the process stream identified as #1, 5, 7-10, and 13-23 so the control efficiencies will apply to those stream.

COMPONENT COUNT	Process Area																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	18a	18b	19	20	21	22	23
	Methanol	Syn Gas		Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	SRU Tail Gas	Low NH3 Concen-tration	Moderate NH3 Concen-tration	High NH3 Concen-tration	Low CO2 Concen-tration	Moderate CO2 Concen-tration	High CO2 Concen-tration	CO2 Product and Purification Compressors	Urea CO2 Compressor	NO2	HNO3	PSA Off Gas	Lower Benzene Concentration	Higher Benzene Concentration
Valves - Gas	0	69	0	342	36	0	0	0	122	98	0	66	197	6	147	20	6	506	0	0	5	0	164	18	0
Valves - Light Liquid	257	0	0	0	546	0	290	285	0	0	0	0	105	2	206	107	0	0	0	0	0	66	0	134	87
Valves - Heavy Liquid	0	0	0	0	0	366	0	0	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps - Light Liquid	4	0	0	0	0	0	6	6	0	0	0	0	6	0	4	6	0	0	0	0	0	2	0	4	2
Pumps - Heavy Liquid	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0
Compressors	0	0	0	0	2	0	0	0	0	0	0	5	0	0	0	0	0	0	10	2	0	0	5		0
Connectors	824	208	0	1024	1642	958	962	932	388	252	118	276	826	44	886	400	34	1446	0	0	34	188	540	474	276
Total	1085	277	0	1366	2226	1332	1258	1223	510	350	135	347	1134	52	1243	533	40	1952	10	2	39	256	709	630	365

CALCULATED EMISSIONS (BY COMPONENT) (lb/day)

Valves - Gas	0	21.7955788	0	108.0302601	0.9097285	0	0	0	3.08296883	2.476483	0	20.847945	4.9782365	0.1516214	3.7147247	0.5054047	0.1516214	12.78674	0	0	0.1263512	0	4.1443188	0.4548643	0
Valves - Light Liquid	6.5760393	0	0	0	13.970885	0	7.42043345	7.29249495	0	0	0	0	2.6867087	0.0511754	5.2710665	2.7378841	0	0	0	0	0	1.6887883	0	3.428752	2.22613
Valves - Heavy Liquid	0	0	0	0	0	4.45403788	0	0	0	0	0.206882	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps - Light Liquid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps - Heavy Liquid	0	0	0	0	0	3.64873428	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressors	0	0	0	0	0	0	0	0	0	0	0	60.318403	0	0	0	0	0	0	0	0	0	0	0	0	0
Connectors	5.58497619	20.13999736	0	99.15075625	11.129285	92.7601802	6.52032415	6.31698763	2.62981889	1.708027	11.42558	26.724227	5.598532	0.2982269	6.005205	2.7111535	0.230448	9.8008199	0	0	0.230448	1.2742421	3.6600572	3.2127169	1.8706959
Total (lb-VOC/day):	12.16	41.94	0.00	207.18	26.01	100.86	13.94	13.61	5.71	4.18	11.63	107.89	13.26	0.50	14.99	5.95	0.38	22.59	0.00	0.00	0.36	2.96	7.80	7.10	4.10

CALCULATED EMISSIONS (BY COMPOUND) (lb/day)	Process Area																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	18a	18b	19	20	21	22	23
	Methanol	Syn Gas		Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	SRU Tail Gas	Low NH3 Concen-tration	Moderate NH3 Concen-tration	High NH3 Concen-tration	Low CO2 Concen-tration	Moderate CO2 Concen-tration	High CO2 Concen-tration	CO2 Product and Purification Compressors	Urea CO2 Compressor	NO2	HNO3	PSA Off Gas	Lower Benzene Concentration	Higher Benzene Concentration
CO_2	0	3.363233208		124.0918985	0	1.99880113	2.18073877	3.72128165	2.8425632	2.534566	0	70.403995	0.7654883	0.1880492	0.1136767	1.1253896	0.1434021	22.081711	0	0	0	0	1.1484529	3.3920472	0.2990683
CO	0	18.14552381		6.143538679	0	0.007363	0.00078068	0.0017284	0.11682651	0.009076	0	2.6511951	0	0	0	0	0	0.001536	0	0	0	0	0.6695686	0	0
CH_4	0	0.247419899		1.240807107	0	0.00030259	0.00062733	0.00175562	0.00011426	0.000364	0	0	0	0	0	0	0	0.0020781	0	0	0	0	0.2419825	0	0
H_2S	0	0.243226342		1.279549957	0	0.05012889	0.12893807	1.3609E-05	1.62588223	0.05637	0.002117	2.1420595	0	0	0	0	0	0.3512817	0	0	0	0	0	0.298046	0.0327746
NH_3	0	0.058709807		0.22023342	0	0.70291391	0	0	0	0.843363	0	0	2.0683464	0.2463383	14.687429	1.8645919	0.1878521	0	0	0	0	0	0	0	0
SO2	0	0		0	0	0	0	0	0.17801618	0	0	0.4149472	0	0	0	0	0	0	0	0	0	0	0	0	0
HCl	0	0		0	0	0.04760731	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NHO3	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6.08E-05	1.6659431	0	0.0012092	0.0006981
NO2	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0259629	0	0	0.0012092	0.0006981
Other	0.03161864	19.77262416		74.19462968	0	97.9753469	0.60679936	0.0367456	0.70783725	0.651746	11.63034	31.960317	10.426486	0.0666362	0.1894712	2.9619123	0.0508152	0.0580726	0	0	0.3307757	1.2972177	5.7422881	0.063867	0
COS	0	0.100645383		0.007872879	0	0.07766447	0.00057157	1.2189E-06	0.15503935	0.087247	0	0.3180614	0	0	0	0	0	0.0023265	0	0	0	0	0	0	0
CH_3OH	12.1293969	0		0.00207181	0	0	11.021326	9.84759023	0.08637735	9.21E-05	0	0	0	0	0	0	0	0.090418	0	0	0	0	0.0020838	3.2856022	3.5560449
C_3H_6	0	0		0	26.009899	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HCN	0	0.004193558		0.000414362	0	0.00282416	0.00041822	0.00024497	0.00013139	0.001691	0	0	0	0	0	0	0	1.753E-05	0	0	0	0	0	0	0
VOC (lb/day) *	12.1293969	~~0.10483894~~	~~0~~	~~0.01035905~~1	26.009899	~~0.08048864~~	11.0223158	9.84783642	~~0.24154809~~	~~0.08903~~	~~0~~	~~0.3180614~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0.0927621~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0.0020838~~	3.2856022	3.5560449
CO (lb/day)	0	18.14552381	0	6.143538679	0	0.007363	0.00078068	0.0017284	0.11682651	0.009076	0	2.6511951	0	0	0	0	0	0.001536	0	0	0	0	0.6695686	0	0

* Per District policy (SSP-2015), VOC emissions are not assessed to components handling fluid streams with a VOC content of 10% of less by weight.

CALCULATED EMISSIONS (BY COMPOUND) (ton/yr)	Process Area																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	18a	18b	19	20	21	22	23
	Methanol	Syn Gas		Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	SRU Tail Gas	Low NH3 Concen-tration	Moderate NH3 Concen-tration	High NH3 Concen-tration	Low CO2 Concen-tration	Moderate CO2 Concen-tration	High CO2 Concen-tration	CO2 Product and Purification Compressors	Urea CO2 Compressor	NO2	HNO3	PSA Off Gas	Lower Benzene Concentration	Higher Benzene Concentration
CO_2	0	0.61379006	0	22.64677147	0	0.36478121	0.39798483	0.6791339	0.51876778	0.462558	0	12.848729	0.1397016	0.034319	0.020746	0.2053836	0.0261709	4.0299123	0	0	0	0	0.2095927	0.6190486	0.05458
CO	0	3.311558094	0	1.121195809	0	0.00134375	0.00014247	0.00031543	0.02132084	0.001656	0	0.4838431	0	0	0	0	0	0.0002803	0	0	0	0	0.1221963	0	0
CH_4	0	0.045154132	0	0.226447297	0	5.5222E-05	0.00011449	0.0003204	2.0852E-05	6.64E-05	0	0	0	0	0	0	0	0.0003792	0	0	0	0	0.0441618	0	0
H_2S	0	0.044388807	0	0.233517867	0	0.00914852	0.0235312	2.4837E-06	0.29672351	0.010287	0.000386	0.3909259	0	0	0	0	0	0.0641089	0	0	0	0	0	0.0543934	0.0059814
NH_3	0	0.01071454	0	0.040192599	0	0.12828179	0	0	0	0.153914	0	0	0.3774732	0.0449567	2.6804557	0.340288	0.034283	0	0	0	0	0	0	0	0
SO2	0	0	0	0	0	0	0	0	0.03248795	0	0	0.0757279	0	0	0	0	0	0	0	0	0	0	0	0	0
HCl	0	0	0	0	0	0.00868833	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NHO3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.11E-05	0.3040346	0	0.0002207	0.0001274
NO2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0047382	0	0	0.0002207	0.0001274
Other	0.0057704	3.608503909	0	13.54051992	0	17.8805008	0.11074088	0.00670607	0.1291803	0.118944	2.122537	5.8327579	1.9028336	0.0121611	0.0345785	0.540549	0.0092738	0.0105983	0	0	0.0603666	0.2367422	1.0479676	0.0116557	0
COS	0	0.018367782	0	0.0014368	0	0.01417377	0.00010431	2.2246E-07	0.02829468	0.015923	0	0.0580462	0	0	0	0	0	0.0004246	0	0	0	0	0	0	0
CH_3OH	2.21361493	0	0	0.000378105	0	0	2.01139199	1.79718522	0.01576387	1.68E-05	0	0	0	0	0	0	0	0.0165013	0	0	0	0	0.0003803	0.5996224	0.6489782
C_3H_6	0	0	0	0	4.7468065	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HCN	0	0.000765324	0	7.56211E-05	0	0.00051541	7.6326E-05	4.4707E-05	2.3979E-05	0.000309	0	0	0	0	0	0	0	3.199E-06	0	0	0	0	0	0	0
VOC (ton/yr)	2.21361493	~~0.019133107~~	~~0~~	~~0.001890527~~	4.7468065	~~0.01468918~~	2.01157263	1.79723015	~~0.04408253~~	~~0.016248~~	~~0~~	~~0.0580462~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0.0169291~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0.0003803~~	0.5996224	0.6489782
CO (ton/yr)	0	3.311558094	0	1.121195809	0	0.00134375	0.00014247	0.00031543	0.02132084	0.001656	0	0.4838431	0	0	0	0	0	0.0002803	0	0	0	0	0.1221963	0	0
	2.21134851	0.019286171		0.001890527	4.7468065	0.01468918	2.00972655	1.79723015	0.04398503	0.016199	0	0.0255943	0	0	0	0	0	0.0169196	0	0	0	0	0.0003797	0.6088833	0.6871094

Based on the location of the stream identified above, steams #1, 2, 4 through 10, 22, and 23 will be assessed to the gasification system permit (S-7616-21); streams #11 through 12 will be assessed to the sulfur recovery system permit (S-7616-23); and steams #13 through 21 will be assessed to the ammonia synthesis unit (S-7616-33). Therefore, fugitive emissions in the amounts listed below will be assessed to those units as:

PE fugitive	VOC (lb/day)	VOC (lb/yr)	CO (lb/day)	CO (lb/yr)	SOx (lb/day)	SOx (lb/yr)		CO2 (lb/day)	CO2 (lb/yr)	CH4 (lb/day)	CH4 (lb/yr)
S-7616-21	65.85	24,036	24.425	8,915	0.178	65	steams #1, 2, 4 through 10, 22, and 23	144.42	52,715	1.491	544
S-7616-23	0.00	0	2.651	968	0.415	151	streams #11 through 12	70.404	25,697	0.000	0
S-7616-33	0.00	0	0.671	245	0.000	0	steams #13 through 21	25.566	9,332	0.244	89

Carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases are classified as greenhouse gases.

APPENDIX F
Emission Information

Table 3-3
Maximum Short-Term Emissions From CTG/HRSG And Coal Dryer Stack During On-Peak Operations

Pollutant	CTG/HRSG Emissions lb/hr	Coal Dryer Emissions lb/hr	Basis	CTG/HRSG Emissions Basis (ppmv)	CTG/HRSG Emissions lb/hr	CTG/HRSG Emissions Basis (ppmv)
	Hydrogen-Rich Fuel			Natural Gas		
NO_X	25.0	4.4	Case 1 (ON Peak, 97°F Ambient)	2.5	34.1	4
CO	18.3	3.2	Case 1 (ON Peak, 97°F Ambient)	3	26.0	5
VOC	3.5	0.6	Case 1 (ON Peak, 97°F Ambient)	1	5.9	2
$PM_{10}/PM_{2.5}$	12.9	1.4	Case 3 (ON Peak, 39°F Ambient)	15 lb/hr	15.0	15 lb/hr
SO_2	4.1	0.9	Case 2 (OFF Peak, 97°F Ambient)	2 ppmv total sulfur in syngas, 10 ppmv sulfur in PSA Off-gas	4.7	12.65 ppm sulfur in natural gas
NH_3	18.5	3.2	Case 1 (ON Peak, 97°F Ambient)	5 ppmv ammonia slip	15.8	5 ppmv ammonia slip

Source: HECA, 2012.

Notes:

Emissions include duct burner operations with syngas and PSA off-gas.

Coal dryer PM emissions controlled to 0.001 gr/dscf by baghouse

gr/dcsf = grain per dry standard cubic feet

CTG/HRSG = Combustion turbine generator/heat recovery steam generator

ppmv = parts per million by volume

NO_X = nitrogen oxides

CO = carbon monoxide

VOC = volatile organic compounds

PM_{10} = particulate matter less than 10 microns

$PM_{2.5}$ = particulate matter less than 2.5 microns

SO_2 = sulfur dioxide

NH_3 = ammonia

°F = degrees Fahrenheit

lb/hr = pound per hour

Table 3-4
CTG/HRSG and Coal Dryer Maximum Annual Operation Emissions

Pollutant	CTG/HRSG, tons/year				Coal Dryer, tons/year		
	Start-Up/ Shut-Down	Operations	Natural Gas Operations	Total	Start-Up/ Shut-Down	Operations	Total
NO_X	4.34	99.6	5.73	109.7	0.54	16.9	17.4
CO	15.7	72.8	4.36	92.9	0.91	12.4	13.3
VOC	0.49	13.9	1.00	15.3	0.04	2.4	2.4
$PM_{10}/PM_{2.5}$	0.82	51.3	2.52	54.6	0.05	5.6	5.6
SO_2	0.147	16.2	0.80	17.1	0.02	2.7	2.8
NH_3	0.00	73.6	2.65	76.3	0.00	12.5	12.5

Source: HECA, 2012.
Notes:
CO = carbon monoxide
CTG/HRSG = Combustion turbine generator/heat recovery steam generator
NH3 = ammonia
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Table 3-5
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

CTG/HRSG Start-Up							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5	lb/hr	2.1	67.1	2270	15.0	65
		lb	1.0	33.6	1135	7.5	32.4
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	2.4	107.2	1044	13.1	13
		lb	4.8	214	2088	26.3	26.8
3. CTG fuel change-over, 40 percent load on syngas, start-up PSA/ammonia/urea units	50	lb/hr	2.4	66.6	81	13	4.6
		lb	120	3329	4052	657	232
Tons/Start-Up			**0.06**	**1.79**	**3.64**	**0.35**	**0.15**
Coal Drying Start-Up							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	0.3	15.1	147.4	0.9	1.9
		lb	0.7	30.3	294.7	1.9	3.8
3. CTG fuel change-over, 40 percent load on syngas	50	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	16.9	470	573	47	33
Tons/Start-Up			**0.01**	**0.25**	**0.43**	**0.02**	**0.02**

Table 3-5
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

CTG/HRSG Shut-Down							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea unit shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	2.4	66.6	81.0	13	4.6
		lb	9.6	266	324	52.6	18.5
2. CTG fuel change-over, 40 percent load on natural gas, gasifier depressurization	3	lb/hr	2.7	122	1191	15.0	15.3
		lb	8.2	367	3574	45.0	45.9
3. Minimum plant load, 20 percent load on natural gas	2	lb/hr	2.1	67.1	2270	15.0	64.8
		lb	4.2	134	4539	30.0	129.7
Tons/Shut-Down			**0.01**	**0.38**	**4.22**	**0.06**	**0.10**
Coal Drying Shut-Down							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea plant shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	1.4	37.6	45.8	3.8	2.6
Tons/Start-Up			**0.00**	**0.02**	**0.02**	**0.00**	**0.00**

Source: HECA, 2012.
Notes:
Basis: Start-up/shut-down procedures provided by MHI.
Coal drying starts at Step 2, above.
$PM_{10}/PM_{2.5}$ emission rate based on 0.001 grain/dscf
CTG/HRSG = Combustion turbine generator/heat recovery steam generator
NH_3 = ammonia
PSA = Pressure Swing Adsorption
NO_X = nitrogen oxides
CO = carbon monoxide
VOC = volatile organic compounds
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide

Table 3-7
Duration and Criteria Pollutant Emissions for Comm. oning of the CTG/HRSG on Natural Gas

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
First fire	4	FSNL	Not operating	8.4	268.4	9,080	260	60
Rotor run-in	12	20%	Not operating	25.2	805	27,240	780	180
Steam blows	168	40%	Not operating	520.8	15,657	152,544	1,966	2,520
Restoration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Initial steam turbine roll	24	40%	Not operating	74.4	2,237	21,792	281	360
NO_X tuning with water injection and initial STG loading	16	40%	Not operating	49.6	174	6057.6	112	240
NO_X tuning with water injection and initial STG loading	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Finalize NO_X control constants	40	40%	Not operating	124	436	15,144	280	600
Finalize NO_X control constants	40	60%	Not operating	160	11,922	14,460	243.2	600
Finalize NO_X control constants	96	80%	Not operating	460.8	37,555	33,072	364.8	1,440
GTG water wash and contractual emission and simple cycle performance testing	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Install SCR and oxidation catalyst	24	80%	Testing	112.8	818	624	142	360
CEMS drift and source testing	64	80%	Operating	300.8	2,182	1,664	377.6	960
Functional testing demonstration hours (six starts)	315	20% to 40%	Operating	859.95	24,466	48,857	1965.6	4,438
Functional testing demonstration hours (six shut-downs)	54	20% to 40%	Operating	139.32	4830.84	50,898	1180.98	810
Functional testing steady state hours	48	80%	Operating	225.6	1,637	1248	283.2	720

Table 3-7
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas (Continued)

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG water wash and preparation for performance testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Continuous operation test	192	80%	Operating	902.4	6,547	4992	1132.8	2880
	1,129	**Total (lb)**		**4,118**	**122,055**	**398,696**	**9,490**	**16,648**
		Total (ton)		**2.1**	**61.0**	**199.3**	**4.7**	**8.3**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Table 3-9
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG starts on natural gas (for 20 starts)	50	20% to 40%	Not operating	116	4,952	64,460	1,184	676
GTG hold time allowance (40% load on H_2-rich fuel)	240	40%	Operating	576	4,795	5,832	1,104	3,120
GTG shut-down hold at 40% load on H_2-rich fuel (for 20 shut-downs)	80	40%	Operating	192	1,598	1,944	368	1,040
GTG fired shut-downs on natural gas (for 20 shut-downs)	100	20% to 40%	Operating	248	7,368	162,260	3,512	1,500
GTG/HRSG standby operation on natural gas	120	40%	Partially Operating	324	1,171	10,004	444	1,800
Gasifier fuel turnover tuning @ 40% H_2-rich fuel	20	40%	Partially Operating	48	1,332	1,620	92	300
CTG NO_X tuning on H_2-rich fuel	16	40%	Partially Operating	38	1,066	1,296	74	240
Gasifier feedstock dryer tuning	24	40%	Partially Operating	58	1,598	1,944	110	360
STG gasifier/SGC steam operation tuning	20	40%	Partially Operating	48	1,332	1,620	92	300
Zero flare tuning	48	40%	Operating	115	3,197	3,888	221	720
CTG NO_X tuning on H_2 rich-fuel	60	75%	Operating	246	1,308	960	186	900
CTG NO_X tuning on H_2 rich-fuel	60	100%	Operating	246	1,500	1,098	210	900
CTG load change testing	60	40% to 100%	Operating	198	2,748	2,982	246	900
CTG trip test	36	40% to 100%	Operating	119	1,649	1,789	148	540

APPENDIX G
Calculation Methodology for General Conformity Mitigation Agreement

HECA	ALT 1 - TRAIN			ALT 2 - TRUCKS		
	NOx	PM10	VOC	NOx	PM10	VOC
2013 Construction	49.9	20.6	5.5	49.9	20.6	5.5
2014 Construction	69	18.5	11.9	69	18.5	11.9
2015 Construction	68.6	21.1	12.4	68.6	21.1	12.4
2016 Construction	45.8	16.9	8.4	45.8	16.9	8.4
2017 Construction	10.06	3.66	1.34	10.06	3.66	1.34
2017 Operation	12.13	1.34	0.6	13.38	2.66	0.97
2018 Operation and beyond	36.4	4	1.8	40.1	8	2.9
District CEQA Thresholds	10	15	10	10	15	10
Conformity Threshold	10	100	10	10	100	10

Notes: Emissions mitigated to satisfy CEQA & Conformity requirements
"Operation" emissions in this table exclude stationary source emissions

	Per Year (Construction)	For 10 years (Operation)
NOx and VOC $/ton (ISR)	$ 9,350	$ 93,500
PM10 $/ton (ISR)	$ 9,011	$ 90,110

Conformity & CEQA

Construction: 363.66 tons, total (NOx+VOC+PM10), for years over threshold

Total Fees
$ 3,507,757

Operation: 40.1 tons/yr (NOx), max year

Total Fees
$ 3,899,324

(Conformity + CEQA) Construction + Operation:

Total Fees
$ 7,407,081

APPENDIX H
Hazardous Air Pollutant Summary

Hydrogen Energy California (HECA) Project
April 19, 2013
Emissions Summary

Compound	CAS #	Annual Rate	CTG/HRSG Stack	Feedstock Dryer Stack	Cooling Tower (Power Block)	Cooling Tower (Process Area)	Cooling Tower (ASU)	Auxiliary Boiler	Ammonia Plant Startup Heater	Emergency Generators	Fire Water Pump	Gasification Flare	SRU Flare	Rectisol Flare	TG Thermal Oxidizer	CO_2 Vent	Manufacturing Complex	Onsite Truck	Onsite Train	Fugitives
		(TPY)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)	(lb/yr)
Acetaldehyde	75-07-0	2.13E-02	3.62E+01	6.38E+00																
Ammonia*	7664-41-7	1.54E+02	1.53E+05	2.50E+04				1.03E+03									1.22E+05			7.61E+03
Antimony	7440-36-0	1.30E-02	2.21E+01	3.90E+00																
Arsenic	7440-38-2	2.85E-02	4.82E+01	8.51E+00	5.33E-02	8.70E-02	2.40E-02	8.89E-02	1.49E-03			1.43E-02	7.75E-04	3.78E-03	2.17E-02					
Benzene	71-43-2	1.47E+00	4.82E+01	8.51E+00				9.33E-01	1.57E-02			1.50E-01	8.14E-03	3.97E-02	2.28E-01	2.79E+03				9.69E+01
Beryllium	7440-41-7	3.08E-03	5.22E+00	9.22E-01				5.33E-03	8.96E-05			8.56E-04	4.65E-05	2.27E-04	1.30E-03					
Cadmium	7440-43-9	1.14E-01	1.93E+02	3.40E+01				4.89E-01	8.21E-03			7.85E-02	4.26E-03	2.08E-02	1.19E-01					
Carbon Disulfide	75-15-0	5.44E-01	9.24E+02	1.63E+02																
Carbonyl Sulfide	463-58-1	2.79E+00														5.37E+03				2.09E+02
Chromium	7440-47-3	6.49E-03	1.02E+01	1.81E+00				6.22E-01	1.05E-02			9.99E-02	5.42E-03	2.64E-02	1.52E-01					
Chromium (hexavalent)	18540-29-9	1.81E-03	3.07E+00	5.43E-01																
Cobalt	7440-48-4	3.10E-03	5.22E+00	9.22E-01				3.73E-02	6.27E-04			5.99E-03	3.25E-04	1.59E-03	9.11E-03					
Copper*	7440-50-8	2.94E-04			1.03E-02	1.69E-02	4.66E-03	3.78E-01	6.35E-03			6.06E-02	3.29E-03	1.61E-02	9.22E-02					
Cyanides	57-12-5	6.91E-02	1.15E+02	2.02E+01																3.35E+00
Fluoride*	1101	1.44E-03			9.31E-01	1.52E+00	4.20E-01													
Formaldehyde	50-00-0	2.25E-01	3.42E+02	6.03E+01				3.33E+01	5.60E-01			5.35E+00	2.91E-01	1.42E+00	8.13E+00					
Hexane	110-54-3	5.89E-01						8.00E+02	1.34E+01			1.28E+02	6.97E+00	3.40E+01	1.95E+02					
Hydrochloric Acid	7647-01-0	1.62E-01	2.61E+02	4.61E+01																1.75E+01
Hydrogen Fluoride (hydrofluoric acid)	7664-39-3	5.91E-01	1.00E+03	1.77E+02																
Hydrogen Sulfide	7783-06-4	2.44E+00														3.04E+03				1.83E+03
Lead	7439-92-1	6.62E-03	1.13E+01	1.99E+00																
Manganese	7439-96-5	1.65E-02	2.09E+01	3.69E+00	2.66E+00	4.35E+00	1.20E+00	1.69E-01	2.84E-03			2.71E-02	1.47E-03	7.18E-03	4.12E-02					
Mercury	7439-97-6	4.88E-03	3.82E+00	5.77E+00				1.16E-01	1.94E-03			1.85E-02	1.01E-03	4.91E-03	2.82E-02					
Methanol	67-56-1	9.73E+00														4.87E+03				1.46E+04
Methyl Bromide (Bromomethane)	74-83-9	5.64E-01	9.59E+02	1.69E+02																
Methylene Chloride (Dichloromethane)	75-09-2	2.60E-02	4.42E+01	7.80E+00																
Naphthalene	91-20-3	2.98E-02	5.02E+01	8.87E+00				2.71E-01	4.55E-03			4.35E-02	2.36E-03	1.15E-02	6.61E-02					
Nickel	7440-02-0	5.30E-03	7.84E+00	1.38E+00				9.33E-01	1.57E-02			1.50E-01	8.14E-03	3.97E-02	2.28E-01					
Nitric Acid*	7697-37-2	3.04E-01																		6.09E+02
Phenol	108-95-2	4.35E-01	7.40E+02	1.31E+02																
Propylene*	115-07-1	4.75E+00																		9.49E+03
Selenium	7782-49-2	6.70E-03	1.13E+01	1.99E+00	4.43E-02	7.23E-02	2.00E-02	1.07E-02	1.79E-04			1.71E-03	9.30E-05	4.53E-04	2.60E-03					
Sulfuric Acid and Sulfates*	7664-93-9	1.12E+00	1.91E+03	3.37E+02																
Toluene	108-88-3	1.50E-03	6.63E-01	1.17E-01				1.51E+00	2.54E-02			2.43E-01	1.32E-02	6.42E-02	3.69E-01					
Vanadium*	7440-62-2	7.52E-04						1.02E+00	1.72E-02			1.64E-01	8.91E-03	4.34E-02	2.49E-01					
Diesel Particulate Matter*	DPM	7.14E-02								4.51E+01	1.84E+00							2.01E+01	7.56E+01	
2-Methylnaphthalene	91-57-6	7.85E-06						1.07E-02	1.79E-04			1.71E-03	9.30E-05	4.53E-04	2.60E-03					
3-Methylchloranthrene	56-49-5	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
7,12-Dimethylbenz(a)anthracene	57-97-6	5.23E-06						7.11E-03	1.19E-04			1.14E-03	6.20E-05	3.02E-04	1.73E-03					
Acenaphthene	83-32-9	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Acenaphthylene	208-96-8	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Anthracene	120-12-7	7.85E-07						1.07E-03	1.79E-05			1.71E-04	9.30E-06	4.53E-05	2.60E-04					
Benz(a)anthracene	56-55-3	2.78E-05	4.62E-02	8.16E-03				8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Benzo(a)pyrene	50-32-8	3.93E-07						5.33E-04	8.96E-06			8.56E-05	4.65E-06	2.27E-05	1.30E-04					
Benzo(b)fluoranthene	205-99-2	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Benzo(g,h,i)perylene	191-24-2	3.93E-07						5.33E-04	8.96E-06			8.56E-05	4.65E-06	2.27E-05	1.30E-04					
Benzo(k)fluoranthene	207-08-9	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Chrysene	218-01-9	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Dibenzo(a,h)anthracene	53-70-3	3.93E-07						5.33E-04	8.96E-06			8.56E-05	4.65E-06	2.27E-05	1.30E-04					
Dichlorobenzene	106-46-7	3.93E-04						5.33E-01	8.96E-03			8.56E-02	4.65E-03	2.27E-02	1.30E-01					
Fluoranthene	206-44-0	9.81E-07						1.33E-03	2.24E-05			2.14E-04	1.16E-05	5.67E-05	3.25E-04					
Fluorene	86-73-7	9.16E-07						1.24E-03	2.09E-05			2.00E-04	1.08E-05	5.29E-05	3.04E-04					
Indeno(1,2,3-cd)pyrene	193-39-5	5.89E-07						8.00E-04	1.34E-05			1.28E-04	6.97E-06	3.40E-05	1.95E-04					
Phenanathrene	85-01-8	5.56E-06						7.55E-03	1.27E-04			1.21E-03	6.59E-05	3.21E-04	1.84E-03					
Pyrene	129-00-0	1.64E-06						2.22E-03	3.73E-05			3.57E-04	1.94E-05	9.44E-05	5.42E-04					
Total Combined HAPs and TACs (tpy)		**180.38**	**79.76**	**13.11**	**0.00**	**0.00**	**0.00**	**0.93**	**0.01**	**0.02**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**8.03**	**61.04**	**0.01**	**0.04**	**1.72E+01**
Total HAPs* (tpy)		**19.90**	**2.43**	**0.43**	**0.00**	**0.00**	**0.00**	**0.42**	**0.01**	**0.00**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**8.03**	**0.00**	**0.00**	**0.00**	**8.38E+00**

Note:
* Denotes pollutants that are not listed as Federal HAPs. These pollutants are not included in the HAP total provided. As shown, combined annual HAP emissions are less than 25 tons per year. Additionally, individual HAP emissions are below 10 tons per year.

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Annual emissions based on 100 percent load at annual average temperature (65°F)

CT Fuel Input (Yearly Average - 65°F) =	2,537	10^6 Btu/hr (higher heating value)
Duct Burner Heat Input (Yearly Average - 65°F) =	290	10^6 Btu/hr (higher heating value)
Total HRSG Heat Input (Yearly Average - 65°F) =	2,827	10^6 Btu/hr (higher heating value)

Hourly emissions based on 100 percent load at average high ambient temperature (97°F)

CT Fuel Input (Avg. High Ambient - 97°F) =	2,583	10^6 Btu/hr (higher heating value)
Duct Burner Heat Input (97°F) =	278	10^6 Btu/hr (higher heating value)
Total HRSG Heat Input (97°F) =	2,861	10^6 Btu/hr (higher heating value)

HRSG

HRSG (Firing Syngas) Normal Operating Hours =	8000	hr/yr
HRSG (Firing Natural Gas) Normal Operating Hours =	336	hr/yr
HRSG Startup Hours =	9	hr/yr
HRSG Shutdown Hours =	18	hr/yr
Total HRSG Operating Hours	**8,363**	**hr/yr**

Feedstock Dryer

Feedstock Dryer Normal Operating Hours =	8000	hr/yr
Feedstock Dryer Startup Hours =	8	hr/yr
Feedstock Dryer Shutdown Hours =	8	hr/yr
Total Feedstock Dryer Operating Hours	**8,016**	**hr/yr**

Exhaust from HRSG normal operation would be splitted into	**85%**	**to HRSG stack**
	15%	**to Feedstock dryer stack**

			HRSG + Feedstock Dryer					
			Toal Hourly Combined Emission	**Total Annual Combined Emissions**	**CTG/HRSG Stack**		**Feedstock Dryer Stack**	
Compound	**CAS #**	**Emission Factor** ($lb/10^{12}$ Btu coal)	**Hourly** (lb/hr)	**Annual** (lb/yr)	**Hourly** (lb/hr)	**Annual** (lb/yr)	**Hourly** (lb/hr)	**Annual** (lb/yr)
Acetaldehyde	75-07-0	1.8	5.15E-03	4.26E+01	4.38E-03	3.62E+01	7.72E-04	6.38E+00
Ammonia	7664-41-7	5 ppm	2.17E+01	1.78E+05	1.85E+01	1.53E+05	3.20E+00	2.50E+04
Antimony	7440-36-0	1.1	3.15E-03	2.60E+01	2.68E-03	2.21E+01	4.72E-04	3.90E+00
Arsenic	7440-38-2	2.4	6.87E-03	5.67E+01	5.84E-03	4.82E+01	1.03E-03	8.51E+00
Benz(a)anthracene	56-55-3	0.0023	6.58E-06	5.44E-02	5.59E-06	4.62E-02	9.87E-07	8.16E-03
Benzene	71-43-2	2.4	6.87E-03	5.67E+01	5.84E-03	4.82E+01	1.03E-03	8.51E+00
Beryllium	7440-41-7	0.26	7.44E-04	6.15E+00	6.32E-04	5.22E+00	1.12E-04	9.22E-01
Cadmium	7440-43-9	9.6	2.75E-02	2.27E+02	2.33E-02	1.93E+02	4.12E-03	3.40E+01
Carbon disulfide	75-15-0	46	1.32E-01	1.09E+03	1.12E-01	9.24E+02	1.97E-02	1.63E+02
Chromium (hexavalent)	18540-29-9	0.15	4.38E-04	3.62E+00	3.72E-04	3.07E+00	6.57E-05	5.43E-01
Chromium	7440-47-3	0.51	1.46E-03	1.21E+01	1.24E-03	1.02E+01	2.19E-04	1.81E+00
Cobalt	7440-48-4	0.26	7.44E-04	6.15E+00	6.32E-04	5.22E+00	1.12E-04	9.22E-01
Cyanides	57-12-5	5.7	1.63E-02	1.35E+02	1.39E-02	1.15E+02	2.45E-03	2.02E+01
Formaldehyde	50-00-0	17	4.86E-02	4.02E+02	4.13E-02	3.42E+02	7.30E-03	6.03E+01
Hydrochloric acid	7647-01-0	13	3.72E-02	3.07E+02	3.16E-02	2.61E+02	5.58E-03	4.61E+01
Hydrogen fluoride (Hydrofluoric acid)	7664-39-3	50	1.43E-01	1.18E+03	1.22E-01	1.00E+03	2.15E-02	1.77E+02
Lead	7439-92-1	0.56	1.60E-03	1.32E+01	1.36E-03	1.13E+01	2.40E-04	1.99E+00
Manganese	7439-96-5	1.0	2.98E-03	2.46E+01	2.53E-03	2.09E+01	4.46E-04	3.69E+00
Mercury	7439-97-6	see notes	1.18E-03	9.59E+00	4.57E-04	3.82E+00	7.20E-04	5.77E+00
Methyl bromide (Bromomethane)	74-83-9	47.7	1.36E-01	1.13E+03	1.16E-01	9.59E+02	2.05E-02	1.69E+02
Methylene chloride (Dichloromethane)	75-09-2	2.2	6.29E-03	5.20E+01	5.35E-03	4.42E+01	9.44E-04	7.80E+00
Naphthalene	91-20-3	2.5	7.15E-03	5.91E+01	6.08E-03	5.02E+01	1.07E-03	8.87E+00
Nickel	7440-02-0	0.39	1.12E-03	9.22E+00	9.48E-04	7.84E+00	1.67E-04	1.38E+00
Phenol	108-95-2	36.8	1.05E-01	8.70E+02	8.95E-02	7.40E+02	1.58E-02	1.31E+02
Selenium	7782-49-2	0.56	1.60E-03	1.32E+01	1.36E-03	1.13E+01	2.40E-04	1.99E+00
Sulfuric acid and sulfates	7664-93-9	95	2.72E-01	2.25E+03	2.31E-01	1.91E+03	4.08E-02	3.37E+02
Toluene	108-88-3	0.033	9.44E-05	7.80E-01	8.03E-05	6.63E-01	1.42E-05	1.17E-01

Notes:

1) For the normal operating scenario, the unit will primarily fire syngas with natural gas as a backup fuel.

2) Emission factors are taken from Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002.

3) Ammonia slip from the SCR (5 parts per million volume dry @ 15 percent O_2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details.

4) Btu = British thermal units.

5) Mercury (Hg) emission estimates are based on the following assumptions for the worst-case 100% coal scenario:

Total gasifier coal feed rate	5023	stpd		
Hg concentration in coal feed	0.13	ppmw		
Total Hg in coal feed	1.306	lb/day	0.0544	lb/hr
Uncontrolled Feedstock dryer Hg emission from volatilization (MHI est)	0.067	lb/day	0.0028	lb/hr
Feedstock dryer Hg emissions control efficiency	75%			
Controlled Feedstock dryer Hg emission from volatilization	0.0168	lb/day	0.00070	lb/hr
Total Controlled Feedstock dryer Hg emission from volatilization + HRSG flue gas	0.0173	lb/day	**0.000720**	lb/hr
Hg in syngas from gasifier	1.289	lb/day	0.0537	lb/hr
Control efficiency of the mercury cleanup in the syngas	99%			
Controlled HG emissions in HRSG flue gas	0.013	lb/day	0.000537	lb/hr
Controlled HG emissions from the HRSG stack	0.011	lb/day	**0.000457**	lb/hr
Total Hg emissions from HRSG + Feedstock dryer	0.028	lb/day	0.001177	lb/hr
Total Hg emissions from HRSG + Feedstock dryer			0.0029	lb/GWh
Gross power output			405	MW

A low gross power rate is used to ensure the emission performance standard is conservative

6) The emission rates of natural gas firing (startup, shutdown, and 336 hours of steady state operation) were calculated based on the emission factors used for the syngas firing.

7) Approximately 15% of the HRSG exhaust is directed to the Feedstock dryer where is passes over pulverized Feedstock to dry it before it is injected into the gasifier. Therefore, it was assumed that HRSG/Feedstock dryer exhaust is split based on 85%/15%. No exhaust will be directed to the Feedstock dryer during natural gas operations or portions of startup and shutdown.

8) Annual emissions for both HRSG and Feedstock dryer based on the higher hours of operation of the HRSG

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Cooling Tower Operating Parameters

	Power Block	Process Area	ASU
Cooling water (CW) circulation rate, gpm =	95,500	162,582	44,876
CW circulation rate (million lb/hr) =	48	81	22
CW dissolved solids (ppmw) =	9,000	9,000	2,000
Drift, fraction of circulating CW =	0.0005%	0.0005%	0.0005%
Cooling Tower Operating Hours	8,668	8,314	8,314
Number of cells in tower	10	11	4

Assumed maximum TDS in circulating cooling water, normally TDS will be less.

Power Block Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	6.15E-06	5.33E-02	6.15E-07	5.33E-03
Copper	7440-50-8	0.005	1.19E-06	1.03E-02	1.19E-07	1.03E-03
Fluoride	1101	0.45	1.07E-04	9.31E-01	1.07E-05	9.31E-02
Manganese	7439-96-5	1.29	3.07E-04	2.66E+00	3.07E-05	2.66E-01
Selenium	7784-49-2	0.02	5.11E-06	4.43E-02	5.11E-07	4.43E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.

2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

3) Copper ppm value shown is one-half of stated detection limit.

4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

6) Selenium ppm value shown taken as average of analytical test results (DWR).

Process Area Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	1.05E-05	8.70E-02	9.51E-07	7.91E-03
Copper	7440-50-8	0.005	2.03E-06	1.69E-02	1.85E-07	1.54E-03
Fluoride	1101	0.45	1.83E-04	1.52E+00	1.66E-05	1.38E-01
Manganese	7439-96-5	1.29	5.23E-04	4.35E+00	4.75E-05	3.95E-01
Selenium	7784-49-2	0.02	8.70E-06	7.23E-02	7.91E-07	6.57E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.

2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

3) Copper ppm value shown is one-half of stated detection limit.

4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

6) Selenium ppm value shown taken as average of analytical test results (DWR).

ASU Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	2.89E-06	2.40E-02	7.22E-07	6.00E-03
Copper	7440-50-8	0.005	5.61E-07	4.66E-03	1.40E-07	1.17E-03
Fluoride	1101	0.45	5.05E-05	4.20E-01	1.26E-05	1.05E-01
Manganese	7439-96-5	1.29	1.44E-04	1.20E+00	3.61E-05	3.00E-01
Selenium	7784-49-2	0.02	2.40E-06	2.00E-02	6.00E-07	4.99E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.

2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

3) Copper ppm value shown is one-half of stated detection limit.

4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).

6) Selenium ppm value shown taken as average of analytical test results (DWR).

Auxiliary Boiler — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Auxiliary Boiler Heat Input =	213	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.203	10^6 scf/hr
Auxiliary Boiler Operating Hours =	2,190	hours per year

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Ammonia	7664-41-7	5 ppm	4.69E-01	1.03E+03
Arsenic	7440-38-2	2.00E-04	4.06E-05	8.89E-02
Benzene	71-43-2	2.10E-03	4.26E-04	9.33E-01
Beryllium	7440-41-7	1.20E-05	2.43E-06	5.33E-03
Cadmium	7440-43-9	1.10E-03	2.23E-04	4.89E-01
Chromium	7440-47-3	1.40E-03	2.84E-04	6.22E-01
Cobalt	7440-48-4	8.40E-05	1.70E-05	3.73E-02
Copper	7440-50-8	8.50E-04	1.72E-04	3.78E-01
Formaldehyde	50-00-0	7.50E-02	1.52E-02	3.33E+01
Hexane	110-54-3	1.80E+00	3.65E-01	8.00E+02
Manganese	7439-96-5	3.80E-04	7.71E-05	1.69E-01
Mercury	7439-97-6	2.60E-04	5.27E-05	1.16E-01
Naphthalene	91-20-3	6.10E-04	1.24E-04	2.71E-01
Nickel	7440-02-0	2.10E-03	4.26E-04	9.33E-01
Selenium	7782-49-2	2.40E-05	4.87E-06	1.07E-02
Toluene	108-88-3	3.40E-03	6.90E-04	1.51E+00
Vanadium	7440-62-2	2.30E-03	4.67E-04	1.02E+00
Benzo(a)pyrene	50-32-8	1.20E-06	2.43E-07	5.33E-04
Benz(a)anthracene	56-55-3	1.80E-06	3.65E-07	8.00E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	3.65E-07	8.00E-04
Chrysene	218-01-9	1.80E-06	3.65E-07	8.00E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	2.43E-07	5.33E-04
Dichlorobenzene	106-46-7	1.20E-03	2.43E-04	5.33E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	3.65E-07	8.00E-04
2-Methylnaphthalene	91-57-6	2.40E-05	4.87E-06	1.07E-02
3-Methylchloranthrene	56-49-5	1.80E-06	3.65E-07	8.00E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	3.25E-06	7.11E-03
Acenaphthene	83-32-9	1.80E-06	3.65E-07	8.00E-04
Acenaphthylene	208-96-8	1.80E-06	3.65E-07	8.00E-04
Anthracene	120-12-7	2.40E-06	4.87E-07	1.07E-03
Benzo(g,h,i)perylene	191-24-2	1.20E-06	2.43E-07	5.33E-04
Benzo(k)fluoranthene	207-08-9	1.80E-06	3.65E-07	8.00E-04
Fluoranthene	206-44-0	3.00E-06	6.09E-07	1.33E-03
Fluorene	86-73-7	2.80E-06	5.68E-07	1.24E-03
Phenanathrene	85-01-8	1.70E-05	3.45E-06	7.55E-03
Pyrene	129-00-0	5.00E-06	1.01E-06	2.22E-03

Notes:

1) Emission factors (lb/106 scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

2) Ammonia slip from the SCR (5 parts per million volume dry @ 15 percent O_2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details.

Ammonia Plant Startup Heater — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Heat Input =	56	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.053	10^6 scf/hr
Operating Hours =	140	hours per year

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.07E-05	1.49E-03
Benzene	71-43-2	2.10E-03	1.12E-04	1.57E-02
Beryllium	7440-41-7	1.20E-05	6.40E-07	8.96E-05
Cadmium	7440-43-9	1.10E-03	5.87E-05	8.21E-03
Chromium	7440-47-3	1.40E-03	7.47E-05	1.05E-02
Cobalt	7440-48-4	8.40E-05	4.48E-06	6.27E-04
Copper	7440-50-8	8.50E-04	4.53E-05	6.35E-03
Formaldehyde	50-00-0	7.50E-02	4.00E-03	5.60E-01
Hexane	110-54-3	1.80E+00	9.60E-02	1.34E+01
Manganese	7439-96-5	3.80E-04	2.03E-05	2.84E-03
Mercury	7439-97-6	2.60E-04	1.39E-05	1.94E-03
Naphthalene	91-20-3	6.10E-04	3.25E-05	4.55E-03
Nickel	7440-02-0	2.10E-03	1.12E-04	1.57E-02
Selenium	7782-49-2	2.40E-05	1.28E-06	1.79E-04
Toluene	108-88-3	3.40E-03	1.81E-04	2.54E-02
Vanadium	7440-62-2	2.30E-03	1.23E-04	1.72E-02
Benzo(a)pyrene	50-32-8	1.20E-06	6.40E-08	8.96E-06
Benz(a)anthracene	56-55-3	1.80E-06	9.60E-08	1.34E-05
Benzo(b)fluoranthene	205-99-2	1.80E-06	9.60E-08	1.34E-05
Chrysene	218-01-9	1.80E-06	9.60E-08	1.34E-05
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	6.40E-08	8.96E-06
Dichlorobenzene	106-46-7	1.20E-03	6.40E-05	8.96E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	9.60E-08	1.34E-05
2-Methylnaphthalene	91-57-6	2.40E-05	1.28E-06	1.79E-04
3-Methylchloranthrene	56-49-5	1.80E-06	9.60E-08	1.34E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	8.53E-07	1.19E-04
Acenaphthene	83-32-9	1.80E-06	9.60E-08	1.34E-05
Acenaphthylene	208-96-8	1.80E-06	9.60E-08	1.34E-05
Anthracene	120-12-7	2.40E-06	1.28E-07	1.79E-05
Benzo(g,h,i)perylene	191-24-2	1.20E-06	6.40E-08	8.96E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	9.60E-08	1.34E-05
Fluoranthene	206-44-0	3.00E-06	1.60E-07	2.24E-05
Fluorene	86-73-7	2.80E-06	1.49E-07	2.09E-05
Phenanathrene	85-01-8	1.70E-05	9.07E-07	1.27E-04
Pyrene	129-00-0	5.00E-06	2.67E-07	3.73E-05

Notes:

1) Emission factors (lb/106 scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Gasification Flare — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV = 1,050 btu/scf

Gasification Flare - Normal Operating Emissions From Pilot

Total Hours of Pilot Operation = 8,760 hr/yr
Flare Pilot Fuel Use = 0.5 10^6 Btu/hr

Gasification Flare - Operating Emissions During Gasifier Startup and Shutdown

	10^6 Btu/yr	Hours per year
Total Flare SU/SD Operation =	70,528	28
Flaring NG-Firing Rate =	2,926	6
Wet Unshifted Gas-Firing Rate =	2,386	4
Dry Shifted Gas-Firing Rate =	2,413	18

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Emission Factor ($lb/10^6$ Btu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	5.57E-04	1.43E-02
Benzene	71-43-2	2.10E-03	2.00E-06	5.85E-03	1.50E-01
Beryllium	7440-41-7	1.20E-05	1.14E-08	3.34E-05	8.56E-04
Cadmium	7440-43-9	1.10E-03	1.05E-06	3.07E-03	7.85E-02
Chromium	7440-47-3	1.40E-03	1.33E-06	3.90E-03	9.99E-02
Cobalt	7440-48-4	8.40E-05	8.00E-08	2.34E-04	5.99E-03
Copper	7440-50-8	8.50E-04	8.10E-07	2.37E-03	6.06E-02
Formaldehyde	50-00-0	7.50E-02	7.14E-05	2.09E-01	5.35E+00
Hexane	110-54-3	1.80E+00	1.71E-03	5.02E+00	1.28E+02
Manganese	7439-96-5	3.80E-04	3.62E-07	1.06E-03	2.71E-02
Mercury	7439-97-6	2.60E-04	2.48E-07	7.25E-04	1.85E-02
Naphthalene	91-20-3	6.10E-04	5.81E-07	1.70E-03	4.35E-02
Nickel	7440-02-0	2.10E-03	2.00E-06	5.85E-03	1.50E-01
Selenium	7782-49-2	2.40E-05	2.29E-08	6.69E-05	1.71E-03
Toluene	108-88-3	3.40E-03	3.24E-06	9.48E-03	2.43E-01
Vanadium	7440-62-2	2.30E-03	2.19E-06	6.41E-03	1.64E-01
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Chrysene	218-01-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	3.34E-03	8.56E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	5.02E-06	1.28E-04
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	6.69E-05	1.71E-03
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	5.02E-06	1.28E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	4.46E-05	1.14E-03
Acenaphthene	83-32-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Anthracene	120-12-7	2.40E-06	2.29E-09	6.69E-06	1.71E-04
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Fluoranthene	206-44-0	3.00E-06	2.86E-09	8.36E-06	2.14E-04
Fluorene	86-73-7	2.80E-06	2.67E-09	7.80E-06	2.00E-04
Phenanathrene	85-01-8	1.70E-05	1.62E-08	4.74E-05	1.21E-03
Pyrene	129-00-0	5.00E-06	4.76E-09	1.39E-05	3.57E-04

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr and plus gasifier startup and shutdown.

2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

SRU Flare — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV =	1,050	btu/scf

SRU Flare - Normal Operating Emissions From Pilot

Total Hours of Pilot Operation =	8,760	hr/yr
Elevated Flare Pilot Fuel Use =	0.3	10^6 Btu/hr

SRU Flare - Operating Emissions During Gasifier Startup and Shutdown

Total Flare Operation During SU/SD =	40.0	hr/yr
Natural Gas Heat Rate (assist gas) =	36.0	10^6 Btu/hr

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Emission Factor ($lb/10^6$ Btu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	6.91E-06	7.75E-04
Benzene	71-43-2	2.10E-03	2.00E-06	7.26E-05	8.14E-03
Beryllium	7440-41-7	1.20E-05	1.14E-08	4.15E-07	4.65E-05
Cadmium	7440-43-9	1.10E-03	1.05E-06	3.80E-05	4.26E-03
Chromium	7440-47-3	1.40E-03	1.33E-06	4.84E-05	5.42E-03
Cobalt	7440-48-4	8.40E-05	8.00E-08	2.90E-06	3.25E-04
Copper	7440-50-8	8.50E-04	8.10E-07	2.94E-05	3.29E-03
Formaldehyde	50-00-0	7.50E-02	7.14E-05	2.59E-03	2.91E-01
Hexane	110-54-3	1.80E+00	1.71E-03	6.22E-02	6.97E+00
Manganese	7439-96-5	3.80E-04	3.62E-07	1.31E-05	1.47E-03
Mercury	7439-97-6	2.60E-04	2.48E-07	8.99E-06	1.01E-03
Naphthalene	91-20-3	6.10E-04	5.81E-07	2.11E-05	2.36E-03
Nickel	7440-02-0	2.10E-03	2.00E-06	7.26E-05	8.14E-03
Selenium	7782-49-2	2.40E-05	2.29E-08	8.30E-07	9.30E-05
Toluene	108-88-3	3.40E-03	3.24E-06	1.18E-04	1.32E-02
Vanadium	7440-62-2	2.30E-03	2.19E-06	7.95E-05	8.91E-03
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Chrysene	218-01-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	4.15E-05	4.65E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	6.22E-08	6.97E-06
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	8.30E-07	9.30E-05
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	6.22E-08	6.97E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	5.53E-07	6.20E-05
Acenaphthene	83-32-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Anthracene	120-12-7	2.40E-06	2.29E-09	8.30E-08	9.30E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Fluoranthene	206-44-0	3.00E-06	2.86E-09	1.04E-07	1.16E-05
Fluorene	86-73-7	2.80E-06	2.67E-09	9.68E-08	1.08E-05
Phenanathrene	85-01-8	1.70E-05	1.62E-08	5.88E-07	6.59E-05
Pyrene	129-00-0	5.00E-06	4.76E-09	1.73E-07	1.94E-05

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr plus gasifier startup and shutdown with assist gas.

2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Rectisol Flare — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV = 1,050 btu/scf

Operating Parameters - Normal Operating Emissions From Pilot

Rectisol Flare Pilot Firing Rate = 0.3 MMBtu/hr
Annual Operating Hours = 8,760 hr/yr

Rectisol Flare - Operating Emissions During Rectisol Startup and Shutdown

Total Flare Operation During SU/SD = 40 hr/yr
Heat Rate of Vent Gas, HHV = 430 10^6 Btu/hr

Compound	CAS Number	Emission Factor ($lb/10^6$ scf)	Emission Factor (lb/MMBtu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	8.20E-05	3.78E-03
Benzene	71-43-2	2.10E-03	2.00E-06	8.61E-04	3.97E-02
Beryllium	7440-41-7	1.20E-05	1.14E-08	4.92E-06	2.27E-04
Cadmium	7440-43-9	1.10E-03	1.05E-06	4.51E-04	2.08E-02
Chromium	7440-47-3	1.40E-03	1.33E-06	5.74E-04	2.64E-02
Cobalt	7440-48-4	8.40E-05	8.00E-08	3.44E-05	1.59E-03
Copper	7440-50-8	8.50E-04	8.10E-07	3.48E-04	1.61E-02
Formaldehyde	50-00-0	7.50E-02	7.14E-05	3.07E-02	1.42E+00
Hexane	110-54-3	1.80E+00	1.71E-03	7.38E-01	3.40E+01
Manganese	7439-96-5	3.80E-04	3.62E-07	1.56E-04	7.18E-03
Mercury	7439-97-6	2.60E-04	2.48E-07	1.07E-04	4.91E-03
Naphthalene	91-20-3	6.10E-04	5.81E-07	2.50E-04	1.15E-02
Nickel	7440-02-0	2.10E-03	2.00E-06	8.61E-04	3.97E-02
Selenium	7782-49-2	2.40E-05	2.29E-08	9.84E-06	4.53E-04
Toluene	108-88-3	3.40E-03	3.24E-06	1.39E-03	6.42E-02
Vanadium	7440-62-2	2.30E-03	2.19E-06	9.43E-04	4.34E-02
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Chrysene	218-01-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	4.92E-04	2.27E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	7.38E-07	3.40E-05
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	9.84E-06	4.53E-04
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	7.38E-07	3.40E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	6.56E-06	3.02E-04
Acenaphthene	83-32-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Anthracene	120-12-7	2.40E-06	2.29E-09	9.84E-07	4.53E-05
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Fluoranthene	206-44-0	3.00E-06	2.86E-09	1.23E-06	5.67E-05
Fluorene	86-73-7	2.80E-06	2.67E-09	1.15E-06	5.29E-05
Phenanathrene	85-01-8	1.70E-05	1.62E-08	6.97E-06	3.21E-04
Pyrene	129-00-0	5.00E-06	4.76E-09	2.05E-06	9.44E-05

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr plus rectisol startup and shutdown.

2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Tail Gas Thermal Oxidizer — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Normal Operations		
Tail Gas Thermal Oxidizer Heat Input =	13	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.012	10^6 scf/hr
Tail Gas Thermal Oxidizer Operating Hours =	8,314	hr/yr
Startup & Shutdown Operations		
Heat Input =	80	10^6 Btu/hr (HHV)
Fuel usage =	0.076	10^6 scf/hr
Startup & Shutdown Hours per year =	72	hr/yr

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.77E-05	2.17E-02
Benzene	71-43-2	2.10E-03	1.86E-04	2.28E-01
Beryllium	7440-41-7	1.20E-05	1.06E-06	1.30E-03
Cadmium	7440-43-9	1.10E-03	9.74E-05	1.19E-01
Chromium	7440-47-3	1.40E-03	1.24E-04	1.52E-01
Cobalt	7440-48-4	8.40E-05	7.44E-06	9.11E-03
Copper	7440-50-8	8.50E-04	7.53E-05	9.22E-02
Formaldehyde	50-00-0	7.50E-02	6.64E-03	8.13E+00
Hexane	110-54-3	1.80E+00	1.59E-01	1.95E+02
Manganese	7439-96-5	3.80E-04	3.37E-05	4.12E-02
Mercury	7439-97-6	2.60E-04	2.30E-05	2.82E-02
Naphthalene	91-20-3	6.10E-04	5.40E-05	6.61E-02
Nickel	7440-02-0	2.10E-03	1.86E-04	2.28E-01
Selenium	7782-49-2	2.40E-05	2.13E-06	2.60E-03
Toluene	108-88-3	3.40E-03	3.01E-04	3.69E-01
Vanadium	7440-62-2	2.30E-03	2.04E-04	2.49E-01
Benzo(a)pyrene	50-32-8	1.20E-06	1.06E-07	1.30E-04
Benz(a)anthracene	56-55-3	1.80E-06	1.59E-07	1.95E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.59E-07	1.95E-04
Chrysene	218-01-9	1.80E-06	1.59E-07	1.95E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.06E-07	1.30E-04
Dichlorobenzene	106-46-7	1.20E-03	1.06E-04	1.30E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.59E-07	1.95E-04
2-Methylnaphthalene	91-57-6	2.40E-05	2.13E-06	2.60E-03
3-Methylchloranthrene	56-49-5	1.80E-06	1.59E-07	1.95E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.42E-06	1.73E-03
Acenaphthene	83-32-9	1.80E-06	1.59E-07	1.95E-04
Acenaphthylene	208-96-8	1.80E-06	1.59E-07	1.95E-04
Anthracene	120-12-7	2.40E-06	2.13E-07	2.60E-04
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.06E-07	1.30E-04
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.59E-07	1.95E-04
Fluoranthene	206-44-0	3.00E-06	2.66E-07	3.25E-04
Fluorene	86-73-7	2.80E-06	2.48E-07	3.04E-04
Phenanathrene	85-01-8	1.70E-05	1.51E-06	1.84E-03
Pyrene	129-00-0	5.00E-06	4.43E-07	5.42E-04

Notes:
1) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Intermittent CO_2 Vent — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Annual operating parameters

Maximum Hours of Operation =	504	hr/yr
For methanol calculations		
Average flow capacity for year =	85%	of maximum (varies between 70% - 100%)

Compound	CAS #	Molecular Weight	Short-term Emission Factor	Long-term Emission Factor	Maximum Hourly Flow	Annual Flow	Hourly	Annual	Annual
		lb/lb-mol	(ppm)	(ppm)	lb/hr	ton/yr	(lb/hr)	(lb/yr)	(ton/yr)
Carbonyl Sulfide	463-58-1	60	10	10	767,435	193,394	10.65	5367	2.68
Hydrogen Sulfide	7783-06-4	34	10	10	767,435	193,394	6.04	3044	1.52
Benzene	71-43-2	78	4	4	767,435	193,394	5.54	2791	1.40
Methanol	67-56-1	32	40	20	767,435	164,385	22.71	4865	2.43

Notes:

1) Vent gas methanol concentrations are based on process licensor data. The methanol concentration is expected to be 18-20 ppm, but could be as high as 40 ppm associated short-term operational conditions such as transient impacts on the wash column.

2) Annual emission rates are based on 504 hours per year of full venting for COS, H2S and benzene and the average venting of 85% flow rate for methanol.

3) VOC emissions calculated from benzene and methanol emissions, reported on a methane basis.

Emergency Diesel Generator — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Emergency Generator Specification =	2,922	Bhp
Emergency Generator Operating Hours =	50	hr/yr

PLEASE NOTE THAT THERE ARE TWO GENERATORS; EMISSION SHOWN IS FOR INDIVIDUAL GENERATORS.

Compound	CAS # /OEHHA reference #	Emission Factor (g/Bhp/hr)	Hourly (lb/hr)	Annual (lb/yr)
Diesel Particulate Matter	9901	0.07	4.51E-01	2.25E+01

Note:

1) Emission factor shown is based on U.S. EPA Tier 4 non-road diesel engine emissions standards.
2) Emission rate shown is for individual generator. There are two generators associated with the Project.

Emergency Diesel Firewater Pump — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Operating Parameters

Fire Water Pump Specification =	556	Bhp
Fire Water Pump Operating Hours =	100	hr/yr

Compound	CAS # /OEHHA reference #	Emission Factor (g/Bhp/hr)	Hourly (lb/hr)	Annual (lb/yr)
Diesel Particulate Matter	9901	0.015	1.84E-02	1.84E+00

Note:

1) Emission factor shown is based on U.S. EPA Tier 4 non-road diesel engine emissions standards.

Urea Absorber

Urea Absorber Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	13.10	105,481

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Urea Pastillation

Urea Pastillation Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	1.03	8,316

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Nitric Acid Unit

Nitric Acid Unit Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	1.03	8,282

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Trucks Operation **HAP Emissions Summary**

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Alternative 1

Data Supplied By Client						
	Onsite Petcoke and Coal Trucks(@ 10 mph)		Fluxant & Product Truck (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
Parameter	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions Diesel LHDT2
Distance Traveled (mile)	0.96		2.49		2.20	1.00
Per Truck Idle Time (hour)		0.083		0.083		
No. Volume Sources On and Offsite on Stn Road	34	2	73	6	5	10
Maximum number of trucks or loads						
1-hour	7	7	9	9	7	10
Annual average	15,200	15,200	21,620	21,620	2,330	100000
EMFAC2007 Emission Factors (g/mi/trk or g/idle-hour/trk)						
PM_{10}	0.087	0.114	0.087	0.114	0.087	0.024

EMFAC emissions are for fleet year 2010. PM10 emission factor does not include tire wear or break wear contributions.
Feedstock and Product truck emissions are for HHD diesel trucks. O&M trucks are light heavy-duty 2 trucks.

PM10 Emission Rates

	Petcoke and Coal Trucks (@ 10 mph)		Fluxant & Product Trucks (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
Emission Rates for HARP	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions Diesel LHDT2
1-hr PM_{10} (pounds per hour)	1.2E-03	1.4E-04	4.2E-03	1.9E-04	3.0E-03	5.3E-04
Annual PM_{10} (pounds per year)	2.8E+00	3.2E-01	1.0E+01	4.5E-01	9.8E-01	5.3E+00

HARP Inputs - Annual and Hourly Emission Rates per Volume Source

	Onsite Petcoke and Coal Trucks (@ 10 mph)		Fluxant & Product Trucks (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions
Max PM_{10} pounds per hour per volume source	3.7E-05	7.1E-05	5.8E-05	3.1E-05	5.9E-04	5.3E-05
PM_{10} pounds per year per volume source	8.2E-02	1.6E-01	1.4E-01	7.5E-02	2.0E-01	5.3E-01

Train Operation - Alternative 1 — HAP Emissions Summary

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Maximum Number of Unit Trains	Coal Unit Train (incoming)	Product Unit Train (outgoing)	Maximum Total Trains per period
1-hour	1	1	1
Annual average	119	165	284

	Switching Engine	Line-haul Engine for Coal Train	Line-haul Engine for Product Train
PM10 Emission Factor (g/bhp-hr)	0.08	0.08	0.08
Conversion Factor (bhp-hr/gal)	15.2	20.8	20.8
PM10 Emissions (lbs/hr /engine)	0.046	0.039	0.026
Engine Power Rating (hp)		4400	3000
Notch Operation		1	1
Notch percentage of hp		5.0%	5.0%
Avg Notch horsepower	260	220	150
# of engines per train	1	2	2
hours to unload/load each train		2	1
max operating hours (hrs/year)	1248		
Number of Volume Sources in AERMOD/HARP	104		

Notes:

Emission factors from EPA's Technical Highlights: Emission Factors for Locomotives, 2009 (http://www.epa.gov/nonroad/locomotv/420f09025.pdf).
The majority of the time the line-haul engine will operate in Notch 1 or idling, therefore emissions were conservatively estimated for Notch 1 horsepower.
Notch percentage presented in PORT OF LONG BEACH AIR EMISSIONS INVENTORY for 2007 (POLB, Jan 2009) derived from EPA data.
New line-haul engines will be AC locomotives such as the GE Evolution Series, that meet Tier 3 emissions
New switching engines will meet Tier 3 emissions, they may be the Titan Trackmobile railcar movers or similar

PM10 Emission Rates

	Switching Engine Emissions	Coal Line-haul Engine Emissions	Product Line-haul Engine Emissions
1-hr PM_{10} (pounds per hour)	0.05	0.08	0.00
Annual PM_{10} (pounds per year)	57.18	18.45	8.72

During a given hour either the line-haul engines for the coal train or product train operate, not both, thus emissions from the larger coal trains are only included in the peak hour emissions.

HARP Inputs - Annual and Hourly Emission Rates per Volume Source

Diesel Particulate Matter	Onsite Train Emissions
Max PM_{10} pounds per hour per volume source	1.2E-03
PM_{10} pounds per year per volume source	8.1E-01

Methanol Tank

Hydrogen Energy California, LLC *19-Apr-2013*
Hydrogen Energy California (HECA) Project

Methanol storage tank parameters and fugitive emissions

Tank ID	Description	Uncontrolled VOC Emissions	Peak Month VOC Emissions	Daily VOC Emissions	Annual VOC emissions
		lb/month	lb/month	lb/day	lb/year
Methanol	Working Loss (33,000 gal pumped in)	82.24	0.0185	-	-
	Breathing Loss	1353.84	0.3049	0.0102	
	Total Breathing and Working Loss		-	0.0287	3.93

Methanol Vent Scrubber Efficiency		
Pre-scrubber	17.76%	methanol
Post-scrubber	40	ppm methanol
Control Efficiency	99.977%	

Methanol concentration information provided by Fluor
Uncontrolled emissions calculated using TANKS model
Peak daily emissions include losses during filling the entire tank plus breathing losses

HECA Project
Major Source Emission Calculations with Significance Thresholds for PSD

Total Reduced Sulfur

Pollutant	Annual Rate (tons per year)	TRS as H2S (tons/yr)	Molecular Wt	Source of emissions		
Hydrogen Sulfide	2.44	2.44	34	CO_2 vent and fugitives		
Carbonyl Sulfide	2.79	1.58	60	CO_2 vent and fugitives	**Significance Threshold (tons/yr)**	**Significant?**
	Total	**4.02**			10.00	no

TRS definition: the total reduced sulfur contained in hydrogen sulfide, mercaptans, dimethyl sulfide, dimethyl disulfide or other organic sulfide compounds, all expressed as hydrogen sulfide. Sulfur dioxide, sulfur trioxide, or sulfuric acid are not to be included in the determination of TRS.

Reduced Sulfur Compounds

Pollutant	Annual Rate (tons per year)	RSC as H2S (tons/yr)	Molecular Wt	Source of emissions		
Hydrogen Sulfide	2.44	2.44	34	CO_2 vent and fugitives		
Carbon Disulfide	0.54	0.24	76	CTG/HRSG and coal dryer		
Carbonyl Sulfide	2.79	1.58	60	CO_2 vent and fugitives	**Significance Threshold (tons/yr)**	**Significant?**
	Total	**4.26**			10.00	no

Reduced sulfur compounds means H2S, carbonyl sulfide (COS), and carbon disulfide (CS2).

Sulfuric Acid Mist

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Sulfuric Acid Mist	1.12	7.00	no	CTG/HRSG and coal dryer

Hydrogen Sulfide

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Hydrogen Sulfide	2.44	10.00	no	CO_2 vent and fugitives

Fluorides

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Fluoride	0.001	3.00	no	Cooling towers

Lead

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Lead	0.007	0.60	no	CTG/HRSG and coal dryer

Pollutants listed above are in 40 CFR 52.21 (as of Apr 6, 2012)

APPENDIX I
Greenhouse Gas BACT Analysis

Greenhouse Gas (GHG)
Best Available Control Technology (BACT) Analysis

Facility Name:	Hydrogen Energy California, LLC	Date: July 5, 2013
Mailing Address:	30 Monument Square, Suite 235 Concord, MA 01742	
Contact Person:	Marisa Mascaro	
Telephone:	(978) 287-9529	
Application #:	S-7616-17-0 through '-40-0	
Project #:	S-1121903	
Deemed Complete:	August 30, 2012	

I. Proposal

Hydrogen Energy California, LLC (HECA) is seeking approval from the San Joaquin Valley Air Pollution Control District (SJVAPCD) for the installation of a power generation facility that uses integrated gasification combined cycle (IGCC), a technology that turns a fuel blend consisting of 75 percent western sub-bituminous coal and 25 percent petroleum coke (petcoke) into a synthesis gas (syngas). The facility will gasify the fuel blend to produce hydrogen-rich syngas and capture a stream that is comprised primarily of carbon dioxide (CO2), a greenhouse gas, and transport it by pipeline to a neighboring oilfield for enhanced oil recovery (EOR) and sequestration.

This document presents the Greenhouse Gas (GHG) Best Available Control Technology (BACT) analysis for the project, which is required due to Rule 2410 (Prevention of Significant Deterioration). Rule 2410 requires new major sources of air pollution to apply BACT for each "regulated pollutant" for which the potential to emit is significant. This document establishes BACT for GHGs from the project. BACT for other pollutants is analyzed in the Rule 2201 BACT discussion.

For the purposes of Rule 2410, GHG includes the following six component pollutants: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons, and perfluorocarbons. Of these six GHGs, CO2 is the dominant GHG emitted for facilities where most of the emissions result from fuel combustion. This is the case for the proposed project, which will, however, produce smaller emissions of CH4, N2O, and SF6. Accordingly, this BACT analysis focuses on the CO2 emissions from the project, but also addresses CH4, N2O, and SF6 emissions.

Rule 2410 requires proposed new projects with carbon dioxide equivalent (CO2e) emissions greater than 75,000 tons per year, and GHGs on a mass basis greater than 100 tons per year (for steam electrical generating units) to demonstrate the use of BACT for their GHG emissions in the pre-construction review.

The proposed project emissions will exceed these thresholds as shown in the table below.[48] The table below presents the annual CO2e emissions from all stationary sources at HECA during the early operations phase. This operational phase represents the maximum total project annual CO2e emissions. Calculation for the annual CO2e emissions shown in the table below are found in Appendix I-A.

Table 1: Maximum Annual CO2e Emissions for Facility S-7616 (Early Operations)

Emission Source	Permitted CO2e Emissions (tonne/yr)[49]	Permitted CO2e Emissions (ton/yr)	Percentage of Total CO2e
Combustion Turbine Generator (S-7616-26-0)	311,918	343,830	57.89%
CO2 Recovery and Vent System (S-7616-24-0)	174,113	191,927	32.31%
Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)	24,757	27,290	4.59%
Nitric Acid Unit (S-7616-35-0)	12,741	14,045	2.36%
Tail Gas Thermal Oxidizer (S-7616-23-0)	6,048	6,667	1.12%
Gasification Flare (S-7616-30-0)	3,980	4,387	0.74%
SRU Flare (S-7616-31-0)	511	563	0.09%
Rectisol Flare (S-7616-32-0)	3,767	4,152	0.70%
Ammonia Synthesis Plant Startup Heater (S-7616-33-0)	417	460	0.08%
Urea Absorbers (S-7616-34-0)	117	129	0.02%
Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0)	304	335	0.06%
Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0)	29	32	0.01%
Fugitives - Gasification Block and Manufacturing Complex	49	54	0.01%
230 kV Circuit Breakers	78	86	0.01%
18 kV Circuit Breakers	8	9	0.00%
Total CO2e/yr for Stationary Sources	538,837	593,965	100.00%

Therefore, BACT is required for GHGs pursuant to Rule 2410. Please note that BACT is also required for NO2, CO, PM, and PM10 pursuant to Rule 2410. BACT for NO2, CO, PM, and PM10 is addressed in Rule 2201 compliance.

[48] GHG emissions are calculated in units of metric tons [(tonne) = 2,205 lb] and short tons [(ton) = 2,000 lb]. GHG emissions are calculated in units of metric tons under the GHG Reporting Program, and are quantified as short tons for PSD purposes.

[49] 1 metric ton (tonne) = 2,204.62 lb

II. Process Description

A. Project Description

The proposed project will remove and capture 90 percent of the carbon from the syngas, and its transport as a pure CO2 stream for use in EOR. This practice results in sequestration (storage) of the CO2 in a secure geologic formation. CO2 will be transported for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills Inc (OEHI). The OEHI EOR project will be separately permitted by OEHI through the appropriate agency, and with SJVAPCD.

The project incorporates a gasification process to convert petcoke and coal into syngas. The primary components of syngas are carbon monoxide (CO) and hydrogen, and the syngas is further processed in a gas treatment unit to remove acid gases (primarily CO2) to produce hydrogen-rich fuel. The treatment of syngas is classified as a pre-combustion treatment process that has advantages over a post-combustion treatment process used for pulverized coal power plants. In the pre-combustion treatment process, the treatment and removal of CO2 and sulfur in syngas occurs at higher pressures and lower volumetric flow rates, which increases the CO2 capture efficiency, in comparison to post-combustion treatment of exhaust gas in a conventional power plant. The gasification process includes all the facilities required to capture and remove CO2 and other constituents from the hydrogen fuel, and delivers the CO2 to OEHI at sufficient pressure and in a suitable physical state for EOR and sequestration.

The removal of CO2 results in hydrogen-rich fuel production with low GHG emissions. The applicant indicates that the proposed project was sited in close proximity to a facility that would purchase and use the CO2 for EOR. The sale of CO2 for EOR improves the economics of producing low-carbon electricity and nitrogen-based fertilizers. The term IGCC generally refers to the use of gasification technology to produce fuel for generation of electricity in a combined-cycle power block. However, products other than power may also be co-produced in an IGCC plant, as is the case for the proposed project.

The proposed project will produce electricity for delivery to the electrical grid controlled by the California Independent System Operator. This is accomplished using a combined-cycle turbine that combusts hydrogen-rich fuel as its primary fuel and natural gas for use as a back-up fuel and during startups and shutdowns.

The combined cycle power block will generate approximately 431 MW of gross power, and will provide approximately 300 MW output of baseload electricity to the grid. The remaining power will be used on-site to meet the facility's internal loads,

and routed to the manufacturing complex for nitrogen-based fertilizer manufacturing. The power block will consist of:

- One Mitsubishi Heavy Industries (MHI) 501 GAC® combustion turbine generator (CTG) that will be fueled with hydrogen-rich fuel from the gasification plant, and natural gas as a backup fuel;

- Heat-recovery steam generator (HRSG) with duct firing on a combination of hydrogen-rich fuel and pressure swing adsorption (PSA) off-gas; and

- Condensing steam turbine-generator.

An integrated manufacturing complex on the HECA site will produce approximately 1 million tons per year of low-carbon nitrogen-based fertilizers, including urea, UAN, and anhydrous ammonia for use in agricultural applications. The manufacturing complex will use the hydrogen-rich fuel from the gasification unit with the majority of the CO2 removed to create nitrogen-based fertilizers with a lower carbon footprint than a facility for the manufacture of similar fertilizers using traditional fossil-fuel sources such as natural gas.

The primary source of GHG emissions from the proposed project is the combustion (oxidation) of the remaining carbon present in the hydrogen-rich fuel stream in the combined-cycle turbine. The GHG emissions resulting from the combustion of the hydrogen-rich fuel are limited, because this fuel has only 10 percent of the carbon from the raw syngas, with the remaining 90 percent captured in the CO2 stream, transported to OEHI for EOR and sequestration, as is explained later in this analysis. A secondary source of emissions will occur intermittently from the gasification block when captured CO2 needs to be vented during plant startups and shutdowns, or when the CO2 compression, transportation, or injection system is unavailable.

B. Project Purpose and Design

Generally, BACT is evaluated for the facility as proposed. It does not regulate the purpose or objective for the proposed facility. The PSD BACT requirements are not meant to be used to redefine the design of the source when considering available control alternatives. Therefore, it is important to clearly state the fundamental purpose and design of the proposed project. The discussion in this section is intended to describe the project objectives in order to provide perspective in determining the range of possible control alternatives that are considered in this BACT analysis, as well as some key project design features.

The purpose of the project is not merely the generation of electricity and nitrogen-based fertilizers. The following are key interrelated elements of the project design and purpose according to the applicant:

- Provide baseload electricity to help meet power needs.
- Enhance the production and availability of nitrogen-based fertilizer products.
- Mitigate impacts related to climate change by reducing average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based fertilizer manufacturing facility by capturing, at a rate of 90 percent, and sequestering CO2.
- Use captured CO2 for EOR to produce additional oil reserves.
- Demonstrate advanced solid-fuel–based technologies and prove carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing.

Each of these elements is critical to the objectives of the project and the design of the source. These are legitimate business goals, important to the project sponsors. They are not incidental, but essential project components. Key project features related to GHG emissions are described below.

Feedstock. Large amounts of petcoke are produced in California and exported overseas. Petcoke and coal are raw materials that are historically inexpensive (per British thermal unit [Btu]) and widely available in the U.S. A purpose of this project is to use these readily available traditional solid raw materials/fuels, and demonstrate their use for the generation of clean, low-carbon electricity.

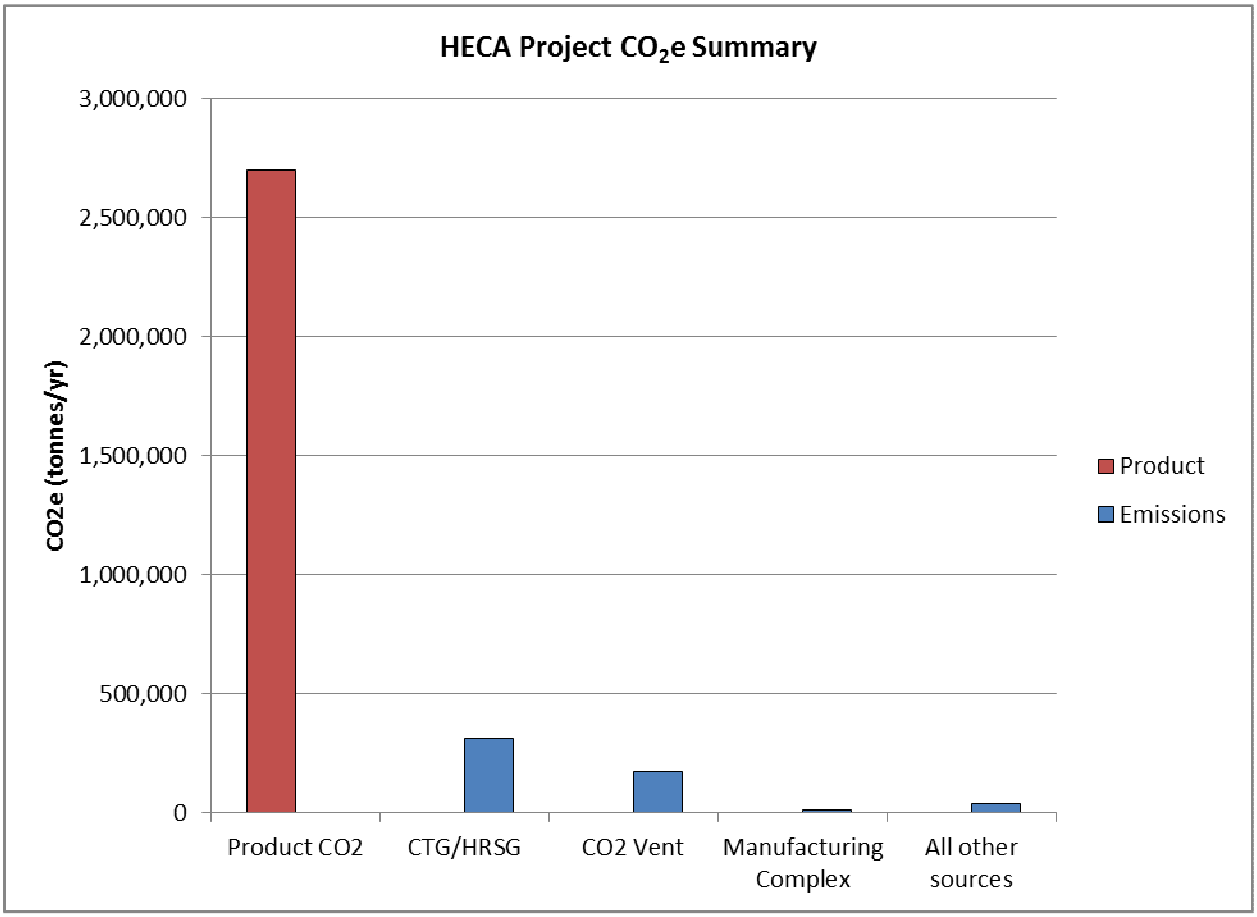
Hydrogen. Hydrogen is one of the cleanest-burning fuels that can be combusted to generate electricity, especially with regard to GHG emissions. A number of demonstration projects employing similar technology have become operational; however, hydrogen use for this purpose has not yet been demonstrated in a large-scale application. The project promotes clean-fuel production and electricity generation, as well as reduction of GHGs through the use of low-carbon fuels. The proposed project will produce clean, gaseous, hydrogen-rich fuel, a key element of the proposed project.

EOR. The project is designed to remove and capture 90 percent of the carbon from the feedstock fuels (as is explained later in this analysis), prior to combustion in the turbine or use in the manufacturing of nitrogen-based fertilizers. The CO2 that is captured from the syngas will be used for EOR in the Elk Hills Oil Field (EHOF) in Kern County, California. This capture step is significant as a demonstration for U.S. Department of Energy (DOE) funding under their “Clean Coal Power Initiative,” as well as integral to the financial objectives of the project.

Part of DOE's purpose, aim, and goals in supporting this project are: "to accelerate the development of advanced coal technologies with carbon capture and storage at commercial-scale. These projects will help to enable commercial deployment to ensure the United States has clean, reliable, and affordable electricity and power."[50]

The HECA facility has been designed with the above objectives in mind. Other means of electrical generation, such as the construction of a conventional natural-gas combined cycle power plant, or a wind- or solar-generating facility, would not satisfy this project's fundamental business and technology demonstration goals.

The extent to which carbon capture reduces CO2 emissions from the facility is illustrated in the graph below. This figure represents the early operations or maximum permitted emissions. As shown, a substantial majority of CO2 generated from the gasification process during normal plant operations will be captured product. This product will be transported to OEHI and used for EOR, resulting in sequestration of the CO2; or used in urea production.



[50] http://www.fossil.energy.gov/recovery/projects/ccpi.html .

C. Overview of Emissions

The GHG emissions from the project will be predominantly from the turbine exhaust from the combustion of uncaptured carbon in the hydrogen-rich fuel or from venting of CO2 during startup and shutdown of the facility and when the CO2 compression, transportation, or injection system is unavailable (as is shown Table 1). Emissions from the proposed project are at their lowest when the entire gasification and hydrogen-production facility is operating, and the CTG and HRSG are operating on hydrogen-rich fuel. However, the CTG will need to fire on natural gas at times (during CTG startups, CTG shutdowns, or during periods of unplanned equipment outages).[51]

There are two factors that are important to a BACT determination for an IGCC/carbon capture and sequestration (CCS) project that directly affect the majority of the potential GHG emissions from such a facility:

- The amount of carbon in the combustion fuel to the turbine and HRSG
- The amount of carbon captured and sequestered from the gasification process as a percentage of the carbon in the syngas

The operation will capture 90 percent of the carbon in the raw syngas, a level which has not been achieved by any other power generation facilities. The removal of carbon, and its subsequent sequestration in EOR and use in the integrated fertilizer manufacturing complex, ensures that the generation of electric power and nitrogen-based fertilizers start from a very low carbon syngas, ultimately lowering the GHGs associated with the generation of these products.

GHG BACT is also proposed with the selection and operation of equipment units capable of combusting fuels that are inherently low in carbon content. The proposed project will achieve low GHG emissions by using hydrogen-rich fuel or Public Utilities Commission (PUC)-regulated natural gas as backup fuel to produce electricity. As shown in Table 5 in this analysis, both of these fuels are recognized as low in carbon content.

Although the GHG BACT will be based on the worst case scenario, which occurs during early operations, it should be noted that GHG emissions are expected to decrease during mature and steady-state operations. GHG emissions were estimated for three HECA operating scenarios, as described below:

[51] Firing of the turbine on natural gas backup fuel will be limited to a maximum of 5 hr/yr during startup events, 10 hr/yr during shutdown events, and 336 hr/yr of unplanned equipment outages.

- Early operations, which are expected to last approximately 2 years, during which time the availability of hydrogen-rich fuel will be approximately 65 to 75 percent. During this period, all sources are expected to be operated at maximum operating conditions, including two plant startups and shutdowns. The CO2 vent is included with maximum permitted venting emissions of up to 504 hours (or equivalent) at full capacity.

- Mature operations, which are expected to occur after the first 2 years of commercial operation, when the availability of hydrogen-rich fuel will be approximately 85 percent. At this stage, significantly less venting is expected to occur. Thus, CO2 vent emissions are estimated based on approximately 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity). All other sources are operated at maximum operating conditions, including two plant startups and shutdowns.

Table 1 in section I of this analysis presents the annual CO2e emissions from all stationary sources at the facility during the early operations phase, which represent the maximum total project annual CO2e emissions.

D. Project Design Features Relevant to GHG BACT

This section discusses some of the overall process design features of the proposed project that will help minimize the proposed facility's GHG emissions.

The MHI oxygen-blown dry-feed gasification technology was identified as the best fit to meet the specific requirements of the project, and to meet key decision criteria, including the lifecycle cost of electricity and reducing technology risk through demonstrated commercial operation with similar feedstock (petcoke and coal), at similar capacity and operating conditions. As part of the design evaluation, the applicant evaluated other gasification technologies, including those of Shell, ConocoPhillips, and General Electric (as explained later in section V.A).

The Mitsubishi's MHI 501 GAC® syngas turbine for this project was selected due to its higher efficiency. MHI's oxygen-blown dry-feed design was chosen because it is more thermally efficient than slurry feed, and the system has been proven to be reliable and economic. Further information on the efficiency of this turbine relative to other turbines that were considered is presented in the energy-efficient turbine discussion in the Top Down BACT Analysis for combined cycle power generating system (S-7616-26-0).

Additionally, the facility proposes to increase its energy efficiency by incorporating heat integration into the process design. Significant heat is generated by the gasification process, and several other plant exothermic chemical reactions. This heat is integrated with, and reused in, other processes that require energy. A

significant amount of this heat is used to generate steam at multiple pressure levels. This steam satisfies the requirements of the gas processing units and other users, with the excess steam sent to the power block for electricity generation.

The following outlines the processes from which heat is recovered and reused for the proposed project:

- Heat is recovered from the gas turbine exhaust and used to generate steam in the HRSG. This steam is primarily used to generate power in the steam turbine generator (STG). A portion of the HRSG flue gas is used to dry the coal and petcoke feedstock upstream of the gasifier unit, instead of using process steam or fuel in a fire heater.

- Heat is recovered from the gasifier by generating steam in the syngas cooler. This steam is used as a source of hydrogen for the gasifier and the shift unit, and also to generate power in the STG.

- Heat is recovered as steam from the shift reaction and recycled to provide hydrogen for the shift reaction. Additional recovered steam and hot water in the shift unit are used for stripping steam, Rectisol® solvent regeneration, boiler feed water heating, syngas heating, and also to generate power in the STG.

- Heat is recovered from the ammonia unit and used to generate steam. This steam provides heat for the urea process and hydrogen for the shift unit.

- Heat is recovered from the UAN unit and used to generate steam. This steam is used to provide hydrogen for the shift unit.

- Heat is recovered from the urea unit and used to generate steam. This steam is used to generate power in the STG.

- Heat is recovered from the sulfur recovery unit (SRU) and used to generate steam. This steam is used mainly in the Rectisol® unit for solvent regeneration and other purposes.

- PSA off-gas is recovered and used as duct-burner fuel to generate additional steam in the HRSG. This steam is used to generate power in the STG.

Furthermore, below are the principle uses of the steam generated from the recovered heat:

- Steam is used for power generation in the steam turbine generator.

- Steam is added to the syngas in the gasification process, a main source of hydrogen for syngas.

- Steam is added to the syngas to enable the water-gas shift reaction, thereby generating more hydrogen while converting CO to CO2, to facilitate CO2 removal from the syngas for sequestration.

- Steam is added to process streams and used for heating in the air separation unit, the urea unit, the acid gas removal unit, the sour water strippers, and water treatment area.

The proposed HECA design features described above are consistent with the major GHG BACT criteria specified in the EPA regulations and guidance; that is, energy efficiency through an integrated facility design that promotes capture and reuse of waste heat in many areas, energy efficiency for major plant processes, and energy efficiency as a criterion for selection of individual equipment. Adoption of this design will enable HECA to produce electricity, a CO2 stream for EOR/sequestration, and nitrogen-based fertilizers on a scale that would otherwise be possible only with substantially higher GHG emissions to the atmosphere

III. GHG BACT Background

A. GHG BACT Applicability

The proposed facility constitutes a new major PSD source. The project CO2e emissions are estimated to be approximately 594,000 tons per year as shown in Table 1 in this analysis. Therefore, Rule 2410 is applicable and GHG BACT will apply to the proposed project.

B. GHG BACT Selection

1. EPA Guidance

The requirement for BACT for GHG emissions is relatively new, only becoming applicable to new projects beginning in January 2011. Therefore, there is little precedent as to what has been deemed acceptable as GHG BACT for many source categories. However, USEPA has issued several guidance documents to assist in development of appropriate GHG BACT analyses for facilities with some equipment and processes in common with HECA. These include:

- *PSD and Title V Permitting Guidance For Greenhouse Gases*, USEPA Office of Air and Radiation, originally proposed in November 2010, updated March 2011 [52]

- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers*, USEPA Sector Policies and Programs Division, Office of Air Quality Planning and Standards, October 2010 [53]

- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry*, USEPA, Office of Air and Radiation, December 2010 [54]

In addition, EPA has published preliminary comments to GHG BACT analyses and that are submitted by states at: http://www.epa.gov/nsr/ghgcomment.html.

These sources, other applications, and draft permits were reviewed to identify the appropriate strategies and control technologies to be included in a GHG BACT. Based on EPA guidance and determinations to date, the major points of evaluation that should be addressed in a GHG BACT analysis include:

- **Equipment energy efficiency.** As stated in page 21 of the EPA March 2011 guidance, EPA believes it is important to evaluate the overall energy efficiency of the source. In general, a more energy-efficient technology burns less fuel than a less energy-efficient technology to achieve the same output. Thus, considering the most energy-efficient technologies helps reduce the products of combustion, both GHGs and criteria pollutants.

- **Process GHG efficiency.** Traditionally, BACT has been evaluated on an emission-unit by emission-unit basis. With GHGs, EPA is further requiring that the overall efficiency of a facility be evaluated.[55] For example, the proposed project's main GHG efficiency will occur through the capture and storage of 90 percent of the CO2 from the raw syngas, plus the designed heat integration of the total facility. The more energy-efficient the process, the less energy will be required, resulting in less GHG emissions.

  Also, according to *PSD and Title V Permitting Guidance For Greenhouse Gases,* for new sources triggering PSD review, the Clean Air Act (CAA)

[52] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[53] http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf
[54] http://www.epa.gov/nsr/ghgdocs/nitricacid.pdf
[55] *PSD and Title V Permitting Guidance For Greenhouse Gases*, USEPA Office of Air and Radiation, originally proposed in November 2010, updated March 2011, p. 23.

and EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis by taking into account operations and equipment which affect the performance of the overall facility. The term "facility" and "source" used in applicable provision of the (CAA) and EPA rules encompass the entire facility and are not limited to individual emission units.

- **Emission limits.** EPA has stated in various comment letters that they expect total CO2e per year emission limits on all permitted sources. In many cases, this limit is set to the full potential to emit of the unit. Nonetheless, it is an imposed emission limit, and the associated monitoring, recordkeeping and reporting requirements are imposed to ensure compliance with the limit.

  Thus, following each summary of the BACT requirement for each of the principal units, there is a discussion of how the GHG emission limits or BACT requirements will be demonstrated.

- **Potentially applicable controls.** EPA is expecting an evaluation of each potentially applicable control measure. This includes switching to a less carbon-intensive fuel, energy efficiency measures (as discussed above), and for the largest sources, add-on controls such as carbon capture and sequestration. However, EPA expects energy efficiency measures (specific to the source under review) to be the predominant resultant BACT determination. For example, to date it is not known of any facilities that have been required to use any add-on controls as GHG BACT.

- **More thorough review for larger sources.** At most facilities, a few types of emissions units within a facility typically result in the vast majority of the GHG emissions. Although BACT is required for all sources of a pollutant under PSD review, the level of detail of the analysis is typically scaled proportional to the magnitude of the emissions. In the GHG BACT analysis for projects such as this one, small emission sources such as the infrequently used emergency engines typically require minimal discussion compared to the larger sources of GHG emissions.

IV. Top Down BACT Process

The top down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The applicant should first examine the highest-ranked option. The top-ranked options should be established as BACT unless the applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

The five-step BACT evaluation process is as follows:

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

The top down BACT analyses for the units emitting GHG at the facility follow.

V. Top Down BACT Analyses

A. Top Down BACT Analysis for Combined Cycle Power Generating System (S-7616-26-0)

As stated earlier in this analysis, the project is designed to generate electricity through the combustion of low-carbon fuel in a combustion turbine generator. After removal of the majority of the carbon from the syngas in the acid gas recovery (AGR) system, the project combustion turbine will fire a hydrogen-rich fuel to generate electricity. Natural gas serves as a backup fuel to allow continuing export of electrical power when hydrogen-rich fuel is not available, and during startup or shutdown[56]. Excess heat in the turbine exhaust will be recovered as steam in the HRSG and used to generate additional electricity with a steam turbine in combined-cycle mode. Produced power will be used on-site to meet the facility's internal load, routed to the manufacturing complex for nitrogen-based fertilizer manufacturing, and exported to the electrical grid. Net electrical generation will be approximately 300 MW. A portion of the HRSG flue gas will be used to dry the coal and petcoke, and this exhaust stream will be emitted from the feedstock dryer stack. The following analysis discusses the GHG emissions generated from the CTG/HRSG and the interconnected feedstock dryer.[57]

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. Capture of 90% of the pre-combustion CO2 through carbon capture and sequestration (CCS) and firing on hydrogen-rich fuel
2. Energy-efficient turbine design
3. Post-combustion CO2 capture and sequestration (CCS)
4. Firing on natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

Each of these control options and their feasibility for this project are discussed below.

[56] Firing of the turbine on natural gas backup fuel will be limited to a maximum of 5 hr/yr during startup events, 10 hr/yr during shutdown events, and 336 hr/yr of unplanned equipment outages.

[57] During normal operation of the CTG/HRSG and some phases of the startup and shutdown activities, a portion of the treated HRSG flue gas will be diverted to the feedstock drying system, filtered through a baghouse, then exhausted from the feedstock dryer stack. As a result, the emissions from the HRSG and feedstock dryer stacks are interconnected.

1. Capture of 90% of the pre-combustion CO2 through carbon capture and sequestration (CCS) and firing on hydrogen-rich fuel

CO2 is a product of combustion generated by carbon-containing fuel. Virtually all the carbon in a fuel becomes CO2 in the combustion exhaust. Therefore, fuels that have lower carbon content, relative to their overall heating value, emit less CO2. The proposed project generates syngas from coal and petcoke feedstock, and removes 90 percent of the carbon (as explained later in this section) to generate a hydrogen-rich fuel, with a lower carbon content, which is then used to fuel the turbine. The plant will be designed to capture 90 percent of the carbon in the total syngas flow, which will exceed the capture proposed for similar facilities, as discussed below.

There are currently two existing operational IGCC facilities in the United States: Duke Energy, Wabash River Generating Station in West Terre Haute, Indiana; and Tampa Electric Company, Polk Power Station in Mulberry, Florida—neither facility employs pre- or post-combustion CCS.[58]

Of the recently permitted IGCC facilities, the Summit Texas Clean Energy Project IGCC Facility in Odessa, Texas, claims that 90 percent of the CO2 in the syngas will be captured for CCS in EOR.[59] For the Taylorville Energy Center near Taylorville, Illinois, there is no requirement for pre- or post-combustion CCS, and the Illinois Environmental Protection Agency determined that "there is no basis for concluding the BACT limit for carbon capture should be 90 percent, which is wholly arbitrary and not supported by material in the record."[60]

The Hyperion Energy Center and the South Dakota Department of Environment and Natural Resources both agreed that CCS was not BACT because it was not feasible due to high costs. The Hyperion Energy Center will use imported solid fuels (petcoke and/or coal) to generate power in its operating "maximum coke design" scenario. The Indiana Gasification Project in Rockport, Indiana, which will generate synthetic natural gas from Illinois coal, is proposing to capture 90

[58] CCS in EOR is not identified in the operating permit for the Wabash River Generating Station, Section A, Source Summary, http://permits.air.idem.in.gov/24473f.pdf, nor is it identified in the PSD document for Polk Power Station, Section 1.1, Introduction, http://www.dep.state.fl.us/air/emission/construction/polk/psd-1.pdf .

[59] Texas Clean Energy Project Final EIS, Volume 1, Chapter 3, Section 3.3.4.4, Greenhouse Gases, http://www.netl.doe.gov/technologies/coalpower/cctc/EIS/final%20eis%20pdf/TCEP%20FEIS%20V1%20Chapter%203.pdf .

[60] Illinois Environmental Protection Agency, Bureau of Air Permit Section, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Christian County Generation for the Taylorville Energy Center in Taylorville, Illinois, April 2012, p. 131, http://www.epa.state.il.us/public-notices/2011/christian-county-generation/responsiveness-summary.pdf .

percent of the CO2 from the SNG, although only 80 percent of that CO2 will be used in EOR and ultimately sequestered, while the remainder will be vented.[61]

Thus, the 90 percent CO2 capture rate that the applicant proposes meets or exceeds other similar facility capture rates when CO2 capture has been proposed. DOC conditions will require that the capture of 90 percent of the pre-combustion CO2 through carbon sequestration shall be demonstrated by monitoring the flow rate and carbon content in the captured CO2 stream and the flow and carbon content of the hydrogen-rich fuel combusted in the CTG/HRSG. Thus, the proposed capture and sequestration significantly reduces GHG emissions over other IGCC facilities that do not sequester CO2.

A portion of clean, hydrogen-rich fuel from the acid gas recovery (AGR) unit will be sent to the pressure swing adsorption (PSA) unit to generate a high-purity hydrogen gas stream for use as a feedstock to the ammonia synthesis unit. The offgas from the PSA unit will be compressed and sent to the HRSG for use as duct-burner fuel. The combustion turbine exhaust gas, supplemental hydrogen-rich fuel for duct-firing, and PSA offgas for duct-firing are used as energy input into the HRSG. Typical compositions of the hydrogen-rich fuel stream and PSA off-gas at HECA are shown in the table below. These low fuel-carbon levels represent the practical limits feasible for use in the proposed turbine and duct burners.

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[61] Hyperion Energy Center, BACT Analysis for Emissions of Carbon Dioxide, March 2009, Section 3.4; Step 4- Evaluate More Effective Control Options, and Appendices A and B, a copy is found at: http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/3FCA842905FE83E78525771A0060F6A3/$File/Exhibit%2035%20CO2%20BACT%20Analysis...3.19.pdf . See also Statement of Basis, Construction Deadline Extension Request for the PSD Permit #28.0701-PSD Hyperion Energy Center, South Dakota Dept. of Environment and Natural Resources, Section 5.6.1; GHG BACT for Process Heaters. http://denr.sd.gov/Hyperion/Air/20110214sb.pdf .

For use of solid fuels, see attached Hyperion Energy Center PSD Permit Application, December 2007, Section 2.1.2; IGCC Power Plant Overview, Page 7, and Section 2.3.1, Feedstock Receiving, Storage, and Preparation, Page 21. http://denr.sd.gov/Hyperion/Air/20071220HyperionApplication.pdf

On page 784 of the document Notice of Public Comment Period for PSD Permit, full venting with no CO2 capture is 6.43 million tons/year and when 80% will go for EOR 1.29 million tons/year is vented. On page 785 of the document "the AGR unit will remove at least 90% of the CO2 in the syngas for liquefaction and sale." http://permits.air.idem.in.gov/30464d.pdf

Table 4: Typical Syngas Fuel Composition		
Component	**H2-rich fuel mole (%)**	**PSA off-gas mole (%)**
Hydrogen	83.8	23.8
Carbon monoxide	1.9	9.1
Carbon dioxide	1.5	7.1
Methane	1.1	5.0
Nitrogen	11.6	54.4
Argon	0.1	0.6
Source: HECA, 2012.		

The proposed HECA fuel treatment process constitutes pre-combustion carbon capture. The use of this process reduces the carbon content of the fuel to the combustion turbine/HRSG, and results in exceptionally low GHG emissions compared with comparable equipment using conventional fossil-fuels levels. The project will capture 90 percent of the carbon in the syngas whenever the gasification system is operating. The captured carbon will be sold as CO2 for EOR, resulting in sequestration, and therefore will not be emitted to the atmosphere. Due to the close proximity of a buyer for the CO2 product for EOR, pre-combustion carbon capture resulting in sequestration is a feasible option for the proposed project.

In addition to the use of hydrogen-rich fuel, the turbine will also be capable of firing on natural gas as a backup fuel (during startups, shutdowns, or during unplanned equipment outages). The project needs the flexibility to fire on natural gas for periods when the gasification system is shutdown or upset, and for facility startups and shutdowns. Natural gas also has lower-carbon content relative to most other fossil fuels.

The table below illustrates CO2 emission factors for a variety of conventional fuels, compared to the fuels proposed for this project.

Table 5: CO2 Typical Emission Factors from Stationary Combustion Sources by Fuel	
Fuel	**lb-CO2/MMBtu**
Petroleum coke [a]	225
Coal [a]	210
Distillate oil [a]	161
Natural gas [b]	116
HECA H2-rich fuel and PSA off-gas [c]	25

Notes:
a. U.S. Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html
b. Project estimates (includes only CO2 in HRSG exhaust stream for the combination of hydrogen-rich fuel and PSA off-gas expected to be used annually)
c. HECA, 2012.

As the CO2 emission factors in the table above indicate, the hydrogen-rich fuel and PSA off-gas will result in lower CO2 emission rates than units using other conventional fossil fuels. Although coal and petcoke cannot be used directly in the HECA combustion turbine, their comparison helps further illustrate how the project's conversion of these solid fuel feedstocks to an inherently low-carbon, hydrogen-rich fuel allows these solid fuels to be used in a way that results in less GHG emissions. The flexibility to use natural gas as a backup fuel, the lowest-carbon conventional fossil fuel, is important to improve the availability and reliability of the proposed facility.

The use of low-carbon, hydrogen-rich fuel, with 90 percent of carbon removed, and natural gas as a backup fuel is an effective method of reducing CO2 emissions. It is technically feasible and is inherent to the design of the proposed facility.

2. Energy-efficient turbine design

Another key component for reducing CO2e emissions is energy efficiency. Because CO2 emissions are directly related to the amount of fuel fired, the more efficient the combustion process, the lower the fuel quantity required, and the lower the GHG emissions that result.

Combined-cycle combustion-turbine generators use an inherently energy-efficient design. A typical configuration is the use of a combustion turbine to generate electricity, with the waste heat in the exhaust used to generate steam in the HRSG. This steam is then expanded in a steam turbine to generate additional electricity.

The proposed MHI 501 GAC® turbine for this project includes operation on both hydrogen-rich fuel and natural gas as backup fuel. The MHI G-Class turbines

have been among the best for economic, efficient, reliable, clean power generation for many years, and MHI has continued to evolve its "G" class technology, with the performance of the current 501 GAC® improved compared with its predecessor. Although this will be the first commercial application of this turbine in hydrogen-rich fuel service for electricity generation, the operating experience of the MHI G-Class turbines in conventional natural-gas combined-cycle service and the MHI 701DA in the Fukushima demonstration IGCC project are key to its selection by the applicant for this project.

GE and Siemens offer F-class hydrogen gas turbines, and their offers are expected to be approximately 2 percent less efficient compared to the MHI 501 GAC® hydrogen-rich turbine, because the G-class turbine is a newer, more-efficient design.[62] The applicant contacted vendors to determine available turbines for hydrogen fuel service. They found that next-generation turbines such as J-Class turbines are not available for the project, because they have not been offered by turbine suppliers for hydrogen-rich fuel. HECA is using the most efficient turbine currently offered by vendors for hydrogen-rich fuel service.

Because the proposed system is designed to optimize IGCC heat integration on hydrogen-rich fuel, operation of the CTG/HRSG using the alternate natural-gas fuel will be somewhat less efficient than a typical natural-gas combined-cycle application. Nevertheless, the specific turbine system is designed specifically for, and required for, the primary operation of the facility—an IGCC with hydrogen-rich fuel.

[62] *Gas Turbine World*, January-February 2012 issue, pp. 28-33.

3. Post-combustion CO2 capture and sequestration (CCS)

The project provides pre-combustion carbon capture and sequestration. As a result, the exhaust stream from the proposed combustion turbine, when firing the hydrogen-rich fuel, will have substantially lower CO2 content than standard fossil fuels. The lower exhaust CO2 content makes "post-combustion" CO2 capture considerably less practical and less achievable than for a high-CO2 stream. The capture of the CO2 from the turbine exhaust is significantly more difficult than in the pre-combustion synthesis gas stream for two predominant reasons: low concentration and low pressure.

Lower concentrations and low pressures mean that a very large volume of gas needs to be treated in order to recover each pound of CO2. This fact is even more relevant for the proposed HECA turbine when firing its primary fuel, hydrogen-rich syngas. These same process factors decrease the driving force for the CO2 to be adsorbed into a solvent. Low-pressure systems entail higher energy demands because solvents designed to absorb significant CO2 at low pressures are difficult from the standpoint of subsequent desorption to regenerate and reuse the solvent. Also, a low-pressure absorption system would create a low-pressure CO2 stream, which would require even greater energy demand for compression to transport the CO2 for EOR.

Post-combustion carbon capture is a relatively new concept and is still in the developmental phase and not yet widely practiced—and never on a hydrogen-rich fuel-combustion turbine exhaust. At the Florida Power and Light natural gas power plant in Bellingham, Massachusetts, a post-combustion carbon capture system called an Econamine FG process was operated from 1991 to 2005. Although the Econamine process claims it can capture CO2 from turbine exhaust with low CO2 and high oxygen concentrations, the CO2 content of the natural-gas exhaust stream is approximately 10 times higher than the hydrogen-fuel exhaust at HECA.[63] The hydrogen-rich exhaust stream for the HECA project has an extremely low CO2 content.

Although chemical solvent/scrubbing systems have been used commercially at some industrial facilities, the implementation of post-combustion CO2 capture systems with this combustion turbine is not considered a commercially available option at this time. No potentially viable technology systems have been tested in post-combustion service at a scale similar to that of the proposed turbine exhaust stream. Developments are generally at an early stage, and the risks to successful commercialization are still high.

[63] See HECA Amendment to the AFC Appendix E-6, page 4 of 15. The natural gas GHG emission factor is 116.98 lb/MMBtu, and the hydrogen-rich syngas emission factor is 17.7 lb/MMBtu.

Although post-combustion carbon capture has been conducted for natural gas turbines on a limited, trial basis, HECA intends to use natural gas only as a backup fuel (only during startups, shutdowns, and during unplanned equipment outages when hydrogen-rich fuel is unavailable) for the turbine. Thus, the extremely limited operations with natural gas would not justify the cost of post-combustion carbon capture.

The fact that the HECA facility will have a Rectisol® acid gas removal (AGR) system and a commercial outlet for captured CO2 does not sufficiently improve the feasibility of carbon capture and sequestration for post-combustion systems. Rectisol® would not be capable of capturing CO2 in the low-pressure turbine exhaust. Rectisol® only works in very high-pressure systems where the high partial pressure of the CO2 allows it to be physically captured by the solvent.

No recently permitted IGCC facilities propose the use of post-combustion capture and sequestration. Based on the lack of any commercial demonstrations of carbon capture on a hydrogen-rich fuel turbine exhaust, the very low concentrations of CO2 in the turbine exhaust when firing the primary fuel, and the limited secondary natural gas fuel usage, post-combustion CO2 capture for the turbine is deemed technically infeasible. Thus, this technology can be removed from consideration.

4. Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

Firing on the backup natural gas fuel is necessary during startup and shutdown of the combustion turbine, and during periods of unplanned gasification equipment outages for up to 336 hours per year (equivalent to 2 weeks per year) when hydrogen-rich fuel is unavailable. Because only two facility startups and shutdowns are planned per year, emissions from all sources will be minimized by limiting the number and hours of plant startups and shutdowns. DOC conditions will provide such limits. GHG emissions during startup and shutdown are based on the amount of fuel burned; thus, minimizing the duration of these events will minimize the GHG emissions. Natural gas usage in the turbine is based on a total of 15 hours in startup and shutdown mode per year, plus 336 hours of normal turbine operation, with no natural-gas duct firing.[64]

[64] Firing of the turbine on natural gas backup fuel will be limited to a maximum of 5 hr/yr during startup events, 10 hr/yr during shutdown events, and 336 hr/yr of unplanned equipment outages.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1 above, post-combustion carbon capture and sequestration can be eliminated as technically infeasible.

Step 3: Rank remaining control options.

The most effective remaining control options for the reduction of GHG emissions are listed below in the order of effectiveness:

1) Capture of 90% of the pre-combustion CO2 through carbon sequestration and firing on hydrogen-rich fuel
2) Energy-efficient turbine design
3) Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

Step 4: Evaluate most effective controls and document results.

All of the controls identified in Step 3 are proposed as GHG BACT. Therefore, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be all of the following:

- Capture of 90% of the pre-combustion CO2 through carbon sequestration and firing on hydrogen-rich fuel
- Energy-efficient turbine design
- Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

Step 5: Select BACT.

The following controls will be required as GHG BACT:

- Capture of 90% of the pre-combustion CO2 through carbon sequestration and firing on hydrogen-rich fuel
- Energy-efficient turbine design
- Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages

DOC conditions will require that the capture of 90 percent of the pre-combustion CO2 through carbon sequestration shall be demonstrated by monitoring the flow rate and carbon content in the captured CO2 stream and the flow and carbon content of the hydrogen-rich fuel combusted in the CTG/HRSG. The installation of proposed energy-efficient turbine model will be specified on the DOC. Additionally, firing on

PUC-quality natural gas will be required as backup fuel, and such operation will be limited to startups, shutdowns, and unplanned equipment outages.

Therefore, compliance with this BACT requirement is expected.

B. Top Down BACT Analysis for CO2 Recovery and Vent System (S-7616-24-0)

In addition to removing sulfur from the syngas, the plant's acid gas removal (AGR) system will capture 90 percent of the carbon in the raw syngas during steady-state operation, and separate it into a high-purity CO2 product stream. This CO2 stream is an important product of the facility. A portion of the captured CO2 will be used in the production of urea, and the majority will be compressed and transported by pipeline to the customer, OEHI, which will use it for EOR in the nearby existing Elk Hills Oil Field (EHOF), resulting in sequestration. The proposed project site was selected in part due to its close proximity to EHOF. The sale of this product for use in EOR is important to the project economics, and sequestration in connection with EOR is an inherent part of the basic design purpose of this project.

Because the CO2 product from this facility is an inherent part of the project's economics, the plant will be designed to provide reliability of the purification and compression facilities needed to deliver it to the transfer point for use by OEHI. However, it is not possible to guarantee 100 percent availability of the pipeline and EOR systems. The CO2 stream will need to be vented during breakdowns, malfunctions, and/or upsets, such as outages of the CO2 compressor or pipeline; or when OEHI is unable to accept the CO2 stream, and during gasifier startup and shutdowns as detailed in the table that follows. The CO2 vent exhaust stream will be nearly 100 percent CO2, with small amounts of other compounds such as CO, VOCs, and H2S.

Approximately 2.6 million tonnes/yr of CO2 will be transported and sold to OEHI. The sale of this stream for EOR and sequestration provides long-term geological storage of the CO2, while also increasing the oil production at EHOF.

Venting duration will be limited to 504 hours (or its equivalent flowrate) per calendar year (equivalent to a total of 21 days), which is based on the types of events that could occur over any 1-year period during early operation: (A) gasification block cold startups; (B) unplanned outages of the CO_2 compressor; (C) unplanned outages of the CO_2 pipeline; and (D) CO_2 off-taker unable to accept. The scenarios shown in the table below were developed by the applicant to provide a conservative estimate of the venting emissions that may be required during the early operations and mature operations. Safe operation of the HECA project is a key factor in considering whether to shut down the gasifier during short, unplanned CO_2 transportation system events. Shutting down the entire gasification block and restarting it increases the risk of upsets, and must be considered when evaluating whether to vent CO_2 or shut down the gasification block.

Table 6: Venting Scenarios				
Scenario for Early Operation				
	Event	**Events per yr**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)** [65]
A	Cold Gasification Block startup	2	3	6
B	CO_2 Compressor unplanned outage	4	2	8
C	CO_2 Pipeline unplanned outage	1	1	1
D	CO_2 off-taker unable to accept	2	3	6
Total Days:				21
Source: HECA, 2012.				

The CO2 compressor will use power generated by the CTG/HRSG, so no additional GHG emissions are associated with this source. The flow rate during these periods of venting will be measured and will be included in the HECA overall recordkeeping requirements under the project's applicable CEC and DOC.

This section of the BACT analysis discusses potential controls for the CO2 vent stream during the intermittent periods when the CO2 product stream cannot be delivered to OEHI.

Step 1: Identify all available control options.

As explained above, the vent stack will allow for infrequent venting of produced CO2 when the CO2 EOR injection system is unavailable or unable to export due to breakdowns, malfunctions, and/or upset conditions; or during gasifier shutdowns and subsequent restarts. The CO2 vent exhaust stream will consist mostly of CO2, with trace levels of certain criteria pollutants and other compounds.

The following technologies have been identified as possible GHG emission controls for this source:

1. Minimize venting of CO2 stream (when injection system is unavailable due to upset condition with such cumulative periods not exceeding 504 hours (or its equivalent flowrate) per rolling 12-month period) and good operating practices of the compression and transportation system

[65] The flow rate of CO2 during venting will vary depending on the operations at the manufacturing complex and power block. Venting is expected to occur at 50 to 85 percent of the maximum designed CO2 venting rate.

2. Storage of the CO2 stream in tanks or vessels (when injection system is unavailable due to upset condition with such cumulative periods not exceeding 504 hours (or its equivalent flowrate) per calendar year).

Each of these control options and their feasibility for this project are discussed below.

1. Minimize venting of CO2 stream and good operating practices of the compression and transportation system

GHG emissions from this source are proposed to be controlled by limiting venting to periods when the compression and transportation systems are unavailable and during gasifier startups and shutdowns, with such time not to exceed 504 hour (or its equivalent flowrate) per rolling 12-month period (equivalent to 21 days, with scenarios itemized in the venting scenarios table above).

Additionally, the use of good operating practices will minimize interruptions to the compression and transportation systems. These practices include regular maintenance of the compression and transportation system. According to the applicant, efforts to assure a high reliability include selection of a compressor with a proven record in similar service, and selection of the Rectisol® acid gas removal technology, which has been in use for decades in facilities worldwide.

2. Storage of the CO2 stream in tanks or vessels

For periods when the pipeline cannot receive the CO2 stream, there are no other alternative CO2 storage options. Building tanks for short-term storage of this product would not be practical or safe. Even compressed to 200 pounds per square inch gauge (psig) (the pressure of a standard propane tank car), the plant's daily production of CO2 would require storage space equivalent to more than 2,000 pressurized railcars (assuming 30,000 gallons each).[66] The only reasonable storage option for large volumes of CO2 is underground geological structures.

[66] Rail cars can hold 30,000 gal and operate at up to 200 psig. From the Ideal Gas Law, 1 lb-mol of any gas @ 14.7 psia and 60 deg F has a volume of about 379 ft^3. MW of CO_2 is about 44 lb/lbmol.

Density of CO_2 at 60 deg F and 200 psig (about 215 psia) = 1 lbmol/379 ft^3 x 44 lb/ lbmol x 215 psia/14.7 psia = 1.70 lb/ft^3

CO_2 maximum production is about 18.3 million lb per day. => CO_2 = 18.3x10^6 lb/day/1.70 lb/ft^3 x 7.48 gal/ft^3/30,000 gal/car = 2684 rail cars/day

Therefore, not venting the gas is not an option as venting is required by the process for safety reasons to prevent potentially dangerous overpressure. The only technology to safely handle this large flow volume in the event of a malfunction is a simple, direct path to atmosphere with no encumbrances. This path is the CO2 vent pipe as designed. Any alternative other than a direct vent would only increase the risk of potentially creating high pressure. This includes alternative compression for storage. Therefore, it is technically infeasible to safely store the CO2 stream on the HECA site.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1, the storage of the vent stream in tanks or vessels can be eliminated as a technically infeasible.

Step 3: Rank remaining control options.

The most effective remaining control options for the reduction of GHG emissions are listed below in the order of effectiveness:

1) Capture, compression, and transportation of the CO2 stream in a pipeline for injection (during normal operation); venting of CO2 stream when injection system is unavailable due to upset condition with such cumulative periods not exceeding 504 hours (or its equivalent flowrate) per rolling 12-month period; and the use good operating practices.

Step 4: Evaluate most effective controls and document results.

As discussed above, the only feasible GHG control alternative for this emissions source the capture, compression, the transportation of the CO2 stream in a pipeline for injection (during normal operations), and the venting of the CO2 stream when the injection system is unavailable due to upset conditions with such cumulative periods not to exceed 504 hours (or its equivalent flowrate) per rolling 12-month period, and the use of good operating practices on the CO2 and transportation system.

Therefore, this is proposed as the most effective control technology.

Step 5: Select the BACT.

The following controls will be required as GHG BACT for the CO2 recovery and vent system:

- Capture, compression, and transportation of the CO2 stream in a pipeline for injection (during normal operation); venting of CO2 stream when injection system is unavailable due to upset condition with such cumulative periods not

exceeding 504 hours (or its equivalent flowrate) per rolling 12-month period; and the use of good operating practices on the CO2 and transportation system.

DOC conditions will limit the venting only to periods when the compression and transportation system is unavailable or CO2 delivery system is unavailable due to cold gasification block startup, CO2 compressor unplanned outage, CO2 pipeline unplanned outage, or CO2 off-taker unable to accept, and such venting shall not exceed 504 hours (or its equivalent flowrate) per rolling 12-month period. Additionally, the daily flow rate of the CO2 vent will be limited though the use of daily emission limits for CO and VOC. Compliance with the limits shall be monitored with a non-resettable, totalizing mass or volumetric flow measure and through speciated vent stream composition source tests required upon startup and during each venting occurrence exceeding 500,000 scf/day.

Therefore, compliance with BACT requirements is expected.

C. Top Down BACT Analysis for Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)

The auxiliary boiler is a pre-engineered package boiler that will provide steam for pre-startup equipment warm-up and for other miscellaneous purposes when steam from the gasification process or HRSG is not available. The auxiliary boiler will be designed to burn PUC-quality natural gas at the design maximum fuel flow rate of 213 MMBtu/hr (high heating value), but will have a much lower average firing rate.[67] The significant heat efficiency and process integration steps discussed in section II.D (Project Design Features Relevant to GHG BACT) of this analysis allow for the auxiliary boiler to be off during normal steady-state, full plant operation.

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. Post-combustion CO2 capture and sequestration
2. Energy-efficient facility design features that allow limited boiler operation;
3. Firing on lower-carbon fuels
4. Energy-efficiency design features (air preheater, economizer, condensate recovery, etc.)
5. Periodic burner tuning

Each of these control options and their feasibility for this project are discussed below.

1. Post-combustion CO2 capture and sequestration;

As discussed under the analysis for the combustion turbine generator, post-combustion CO2 capture is a relatively new concept, which is rarely used on combustion systems. Unlike the gasification acid gas removal (AGR) system, which generates a concentrated CO2 stream ideal for capture, capture of the CO2 from the boiler exhaust is significantly more difficult because the CO2 is at a low concentration and low pressure.

CO2 post-combustion capture systems for small- to medium-sized combustion systems are not economically viable as supported by the EPA GHG BACT guidance document, which recommends that carbon capture and sequestration (CCS) only needs to be considered in a BACT analysis for very large CO2

[67] The average annual firing, allowing for startups, shutdowns, and partial load situations, will be limited by DOC condition to 466 billion Btu per calendar year, which is equivalent to an average of 53.3 MMBtu/hr over the course of a year.

sources and industrial facilities with high-purity CO2 streams (cement production, iron and steel, etc.).[68]

Therefore, post-combustion CO2 capture for the small, limited-use auxiliary boiler is not a technically feasible option. Thus, this technology can be removed from consideration.

2. Energy-efficient facility design features that allow limited boiler operation

The overall heat integration and energy efficiency measures incorporated into the plant design effectively eliminate the need for any auxiliary boiler firing during normal steady-state operation. As is explained in section II of this analysis, the facility is designed to recover the heat from various units, and steam generated in used in various processes at the facility.

These integrated plant design characteristics are the most significant measures in reducing GHG emissions from this source. Due to the proposed plant design features, the auxiliary boiler will operate in standby service most of the time. Therefore, the limited operation of the boiler (which is identified as a control option below) is enabled through the energy-efficient facility design.

By proposing an energy-efficient facility design, the proposed boiler will only need to operate on a limited basis. The auxiliary boiler's annual fuel firing rate will be limited to 466 billion Btu per year, which is equivalent to 25 percent capacity annually. DOC conditions will restrict the annual firing rate of the boiler to 466 billion Btu per year.

3. Firing on lower-carbon fuels

CO2 is a product of combustion generated with any carbon-containing fuel. The preferential use of natural gas in the auxiliary boiler, a lower-carbon fuel, is a highly effective method of reducing CO2 emissions versus use of solid fuels. The proposed project auxiliary boiler will fire natural gas as a lower-carbon fuel. Firing on hydrogen-rich fuel is infeasible because this fuel stream will be unavailable during most of the periods when this boiler would be in use (startups, shutdowns, upsets). Also, because reliability of this boiler is important for emergency situations, the use of more reliable natural gas is preferred, even if hydrogen-rich fuel had been available.

[68] *PSD and Title V Permitting Guidance For Greenhouse Gases*, March 2011, USEPA Office of Air and Radiation, pp. 35 - 36. http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf .

4. Energy-efficiency design features

Another opportunity for reducing GHG emissions is to maximize the energy efficiency of the boiler. Because CO2 emissions are a direct result of the amount and rate of fuel fired (for a given fuel), a more efficient boiler requires less fuel and produces lower GHG emissions than a less efficient one.

Three energy efficiency measures have been identified that may be applied to this combustion source.

4a. Economizer

An economizer is used to recover additional heat from the boiler exhaust to preheat boiler feed water. This reduces the heat energy required from fuel combustion to heat the boiler water.

4b. Condensate recovery

As the boiler steam is used in the heat exchanger, it condenses. When hot condensate is returned to the boiler as feedwater, the boiler heating load is reduced and the thermal efficiency increases.

4c. Inlet air trim controls

Inlet air trim controls can limit excess air by using a stack CO or oxygen (O2) monitor and automatically adjusting inlet air. Limiting the excess air enhances efficiency and reduces emissions by reducing the volume of air that needs to be heated in the combustion process.

The auxiliary boiler is proposed to include a heat recovery economizer and condensate recovery, but not inlet air controls. Optimizing excess air can be a cost-effective measure on large boilers, but it is not cost effective for small boilers or limited use boilers. According to the USEPA's Boiler White Paper, manufacturers estimate that a 1 percent thermal efficiency increase can be achieved with oxygen trim control.[69] The firing of this auxiliary boiler is limited to no more than 213 MMBtu/hr and 466 billion Btu per year, which is equivalent to an annual average firing rate of 53.3 MMBtu/hr. At this rate, an improvement of 1 percent thermal efficiency (resulting in 1 percent lower firing) would reduce annual GHG emissions by only about 270 ton per year. Due to the small size of

[69] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers*, USEPA, October 2010, p. 14.

this boiler and the overall small emissions from this source, the application of inlet air controls is not justified, and is not considered further in this analysis.

4d. Heat exchanger

One other possible boiler energy efficiency step would be to install a heat exchanger for recovery of the heat from boiler blowdown. However, the relatively small size of this boiler and its infrequent operation does not justify the incremental costs for this measure.

The auxiliary boiler make and model have not yet been selected; however, based on vendor experience, and the boiler features specified, such as an economizer (boiler feed water heater) and condensate recovery, it is expected that the boiler efficiency will be approximately 90 to 92 percent, lower heating value (equivalent to about 81 to 83 percent, higher heating value).

5. Periodic boiler tuning

A combustion system can drift over time from its optimum setting. Therefore, tuning of the boiler at least twice per calendar year is deemed a technically feasible option. Although the boiler tuning requirements of SJVAPCD Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) only apply to low-use units instead of compliance with all the emission limits of the rule, tuning twice per calendar year has been shown to be technically feasible, so this control will be carried forward for consideration.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1, post-combustion CO2 capture and sequestration and inlet air trim controls can be eliminated as technically infeasible.

Step 3: Rank remaining control technologies.

It is proposed that all of the remaining control options identified by implemented to reduce GHG emissions. Therefore, there is no need to rank the control technologies.

- Limited operation (annual fuel firing rate limited to 466 billion Btu per year)
- Firing on a lower-carbon fuel (PUC-quality natural gas)
- Energy-efficiency measures (economizer and condensate recovery)
- Tuning the boiler twice per calendar year

Step 4: Evaluate most effective controls and document results.

All of the controls identified in Step 3 are proposed as GHG BACT. Therefore, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be all of the following:

- Limited operation (annual fuel firing rate limited to 466 billion Btu per year)
- Firing on a lower-carbon fuel (PUC-quality natural gas)
- Energy-efficiency measures (economizer and condensate recovery)
- Tuning the boiler twice per calendar year

Step 5: Select the BACT.

The following controls will be required as GHG BACT:

- Limited operation (annual fuel firing rate limited to 466 billion Btu per year)
- Firing on a lower-carbon fuel (PUC-quality natural gas)
- Energy-efficiency measures (economizer and condensate recovery)
- Tuning the boiler twice per calendar year

DOC conditions will require all of the above technologies, thus GHG BACT for this unit will be satisfied. Conditions will require that the boiler be fired solely on PUC-quality natural gas and that it be equipped with an economizer and a condensate recovery system. The boiler shall also be required to be equipped with a fuel flow meter and will require recordkeeping to demonstrate compliance with the annual fuel firing rate limit of 466 billion Btu per year. Conditions will also require that the boiler be tuned twice per calendar year.

Therefore, compliance with BACT requirements is expected.

D. Top Down BACT Analysis for Tail Gas Thermal Oxidizer (S-7616-23-0)

Associated with the operation of the sulfur recovery process, the project will incorporate a thermal oxidizer on the tail-gas treating unit. The thermal oxidizer will serve as a control device to oxidize any remaining H2S (after scrubbing) and other vent gas that is generated during startup, shutdown, and times of non-delivery of CO2 product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. The thermal oxidizer operates at high temperatures, and provides sufficient residence time in order to ensure essentially complete oxidation of reduced sulfur compounds, e.g. H2S to SO2.

The thermal oxidizer will continuously fire at a firing rate limited to 13 MMBtu/hr to maintain the required operating temperature for proper thermal destruction. The thermal oxidizer fires an additional 80 MMBtu/hr of natural gas for the periodic oxidation of vent gas during SRU startups (which will be limited to 48 hours per year) and plant maintenance (which will be limited to 48 hours per year). The GHG emissions from this source represent approximately 1.1 percent of the total CO2e that will be emitted from the facility (as shown in Table 1). The following sections briefly analyze potential GHG controls for this source.

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. Post-combustion CO2 capture and sequestration
2. Use of lower-carbon fuel
3. Limited operation
4. Energy-efficient design

Each of these control options and their feasibility for this project are discussed below.

1. Post-combustion CO2 capture and sequestration

Post-combustion CO2 capture and sequestration is not technically feasible for the thermal oxidizer for the same reason it is not feasible for the combustion turbine and auxiliary boiler as explained in the previous sections. This source is even smaller than the combustion turbine and auxiliary boiler, and it would be even more difficult, expensive, and uncertain to attempt implementation of the

technology for these services. Therefore, this option can be eliminated as technically infeasible.

2. Use of lower-carbon fuel

Because the hydrogen-rich fuel that is generated at the facility and used in the combustion turbine, it is not available during startups. Thus, firing on hydrogen is not a suitable failsafe fuel source for the thermal oxidizer. The applicant proposes to fire on another lower-carbon fuel, PUC-quality natural gas, instead.

3. Limited operation

Continuous operation of the thermal oxidizer to control miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. During these instances and during catalyst presulfiding the thermal oxidizer will be limited to firing of 13 MMBtu/hr of natural gas. Venting associated with startup operations of the SRU will fire an additional 80 MMBtu/hr of natural gas, but such operation will be limited to 48 hours per year by DOC condition. Venting associated with plant shutdown for annual maintenance of the SRU (passivation) will fire an additional 80 MMBtu/hr of natural gas, but such operation will be limited to 24 hours per year by DOC condition. This will limit the GHG emissions associated with this unit.

4. Energy-efficient design

The thermal oxidizer will be a very small source as it accounts for approximately 1.1 percent of the total CO2e generated by the project. The thermal oxidizer will not be equipped with air inlet controls or heat recovery because it has only a simple, small burner, which precludes these control options as technically or economically feasible measures for this unit. No applicable energy-efficiency measures are identified to carry forth in the BACT analysis.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1, the use of a lower-carbon fuel (such as hydrogen-rich fuel), a more energy-efficient design, and post combustion CO2 capture and sequestration can be eliminated as a technically infeasible.

Step 3: Rank remaining control options.

It is proposed that all of the remaining control options identified by implemented to reduce GHG emissions. Therefore, there is no need to rank the control technologies.

- Firing on PUC-quality natural gas
- Sulfur recovery unit startup venting limited to 48 hour per calendar year

Step 4: Evaluate most effective controls and document results.

All of the controls identified in Step 3 are proposed as GHG BACT. Therefore, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be all of the following:

- Firing on PUC-quality natural gas
- Sulfur recovery unit startup venting limited to 48 hours per calendar year

Step 5: Select the BACT.

The following controls will be required as GHG BACT:

- Firing on PUC-quality natural gas
- Sulfur recovery unit startup venting limited to 48 hours per calendar year

Compliance with these BACT requirements will be ensured with DOC conditions that require that the unit be fired solely on PUC-quality natural gas, by limiting the venting from SRU startups to 3,840 MMBtu per calendar year which is equivalent to 48 hours per calendar year, and from SRU maintenance to 1,920 MMBtu per calendar year which is equivalent to 24 hours per calendar year and require that the fuel flow rate to the thermal oxidizer be monitored.

Therefore, compliance with BACT requirements is expected.

E. Top Down BACT Analysis for Flares (S-7616-30-0, -31-0, and -32-0)

Although the project is designed to avoid flaring during steady-state operations, flares are needed for safe operations in upset conditions and to protect the operators and equipment. The project employs three pressure-relief systems and their corresponding flares (one flare primarily serving the gasification block, another primarily serving the sulfur recovery unit, and a third primarily serving the Rectisol unit) for this purpose. All three flares are conventional pipe, elevated flares, with natural gas-fired pilots. Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment, and to allow safe venting of gases during routine startup, shutdown, or emergency upset events. During typical, non-startup plant operation, the three flares will be operated in a standby mode with only minimal emissions from the natural-gas pilot flames. The flares will also be used occasionally to dispose of excess startup and shutdown gases in a safe manner. Any time the flares are used, GHG emissions will be generated, although the total annual CO2e emissions from these flares are expected to be approximately 1.5 percent of the facility total.

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. Minimization of flaring and preparation of a flare minimization plan; and
2. Flare gas recovery system.

Each of these control options and their feasibility for this project are discussed below.

1. Minimization of flaring and preparation of a flare minimization plan

The principal method to minimize GHG emissions from the flares is to minimize the amount of material vented to the flares. As described above, the flares are used to safely dispose of gases containing VOCs and hazardous air pollutant constituents. Any time these gases are combusted in the flares, emissions of CO2, CH4, and N2O are generated. Flare minimization is equally important to minimizing criteria pollutants, and has been incorporated into the base facility design and the DOC conditions. The DOC conditions will limit flaring by limiting the annual volume of gas sent to each flare, and the durations of planned flaring events. Compliance with these conditions will be verified through non-resettable total flow meters for each flare. In addition to the fuel used for the pilot, each flare will be limited to the following planned operations:

- Gasification block flare: planned use limited to 74,914 MMBtu per year (21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; and 43,434 MMBtu/yr of shifted gas);

- Sulfur recovery unit flare: planned use limited to 36 MMBtu/hr of natural gas assist for 40 hours per year during startups and shutdowns;

- Rectisol unit flare: planned use limited to 430 MMBtu/hr of natural gas assist for 40 hours per year during startups and shutdowns.

The permittee will be required to submit a Flare Minimization Plan that complies with SJVAPCD Rule 4311, which will contain technical specifications of each flare, including process flow diagrams, and a description of equipment, processes, or procedures that will be implemented to eliminate or minimize flaring. It will also include an evaluation of preventive measures to reduce flaring that may be expected to occur during planned major maintenance activities, including startup and shutdown, and an evaluation of these measures.

The permittee plans two facility startups and shutdowns per year; emissions from the flares will be minimized by the fuel usage limits. GHG emissions during startup and shutdown are based on the amount of fuel flared. Therefore, minimizing the duration of these events will also minimize the GHG emissions.

2. Flare gas recovery

Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, a flare gas recovery for the HECA facility is not feasible, for the following reasons.

First, unlike a refinery, which can and does need to operate sections of the plant while other sections are down for maintenance, HECA's planned maintenance will occur during an entire plant shutdown, while no gases are being produced. Flaring at the proposed HECA facility will be an infrequent occurrence, limited to breakdowns, malfunctions, and/or upsets. Planned flaring occurs during gasifier startup and shutdown, which is estimated to occur for approximately 40 hours per year for the Rectisol® and SRU flares; and about 28 hours for the gasification flare.

Another significant difference is that refineries can recover some flare gas into their fuel gas cleanup system, which typically operate at less than 100 psig. In contrast, the HECA facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of approximately 900 psig. This would significantly

increase the equipment and operating costs of a flare gas recovery compressor, versus those at refineries. Further, during some of the flaring events, the flared material may not be suitable for routing to the AGR system, or the AGR system itself may be in the process of startup, in an upset, or otherwise not ready to receive the gases.

Given the extremely infrequent nature of events producing flared gases available for recovery and the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged not to be feasible for the HECA facility.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1, the use of a flare gas recovery system can be eliminated as a technically infeasible.

Step 3: Rank remaining control technologies.

After eliminating the infeasible technologies for the thermal oxidizer, the remaining control option is:

1. Minimization of flaring and the preparation of a flare minimization plan.

Step 4: Evaluate most effective controls and document results.

The only control identified in Step 3 is proposed. Therefore, there no need to further evaluate the controls further.

Step 5: Select the BACT.

The following controls will be required as GHG BACT:

- Minimization of flaring and the preparation of a flare minimization plan.

DOC conditions will limit the planned flaring, and a flare minimization plan will be required for each flare to limit the GHG emissions.

Therefore, compliance with BACT requirements is expected.

F. Top Down BACT Analysis for Nitric Acid Unit (S-7616-35-0)

The nitric acid plant is the largest source of GHG emissions within the fertilizer manufacturing complex. Its CO2e emissions are approximately 2.4 percent of the total facility CO2e emissions as shown in Table 1. Nitrous oxide (N2O) emissions are a byproduct of the process stream in nitric acid production, and are considered "industrial process" emissions, resulting from ammonia oxidation.[70] There are several factors that affect N2O formation, including combustion conditions in the oxidizing unit, catalyst, and burner design. The uncontrolled default N2O emission factor used for nitric acid plants from the Intergovernmental Panel on Climate Change guidelines for U.S. facilities is 9 kilograms per metric ton (tonne) of nitric acid (HNO3) produced (18 pounds N2O per ton of HNO3).[71] This value was used by EPA in the development of the recent U.S. GHG inventory.[72]

Step 1: Identify all available control technologies.

A review of the USEPA guidance document "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry"[73] provided a description of the available controls for N2O at nitric acid plants. These controls are distinguished by the location of the control measure within the nitric acid production process. The following technologies have been identified as possible GHG emission controls for this source:

1. Primary controls (suppression of N2O formation)
2. Secondary controls (catalytic N2O decomposition in the oxidation reactor)
3. Tertiary controls (catalytic reduction or catalytic decomposition)

Each of these control options and their feasibility for this project are discussed below.

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[70] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry*, USEPA, Office of Air and Radiation, December 2010. http://www.epa.gov/nsr/ghgdocs/nitricacid.pdf.

[71] *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use*. Intergovernmental Panel on Climate Change, ISBN 4-88788-032-4. http://www.ipccnggip.iges.or.jp/public/2006gl/vol3.html.

[72] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008*. EPA 430-R-10-006. Washington, D.C. April 15, 2010. http://epa.gov/climatechange/emissions/downloads10/508_Complete_GHG_1990_2008.pdf.

[73] http://www.epa.gov/nsr/ghgdocs/nitricacid.pdf

1. Primary control (suppression of N2O formation)

Primary control reduces the amount of N2O formed in the ammonia oxidation step. This can be done by modifying the catalyst used in the oxidation process and/or modifying the operating conditions of this process. Primary controls are categorized as the suppression of N2O formation, and include modifications to reactor design and catalysts; emission reduction is expected to be between 30 and 85 percent. According to the EPA guidance document, data from 14 European units with improved oxidation catalyst showed emissions in the range of 7.2 – 19.4 pounds N2O per ton of HNO3.[74]

2. Secondary control (catalytic N2O decomposition in the oxidation reactor)

Secondary control reduces N2O immediately after it is formed in the ammonia oxidation step. Secondary controls are categorized as catalytic decomposition of N2O (to nitrogen [N2] and O2) in the oxidation reactor, where they selectively remove N2O. Reduction efficiencies for secondary controls range from 70 to 90 percent. The EPA guidance document reports that many secondary catalysts can achieve emission rates lower than 3 pounds of N2O per ton of HNO3.[75]

3. Tertiary control (catalytic reduction or catalytic decomposition)

Tertiary control reduces N2O by installation of a catalytic reactor either upstream or downstream of the tail-gas expansion unit following ammonia oxidation. Tertiary controls are categorized as catalytic reduction or catalytic decomposition in a catalytic reactor following the ammonia oxidation process.

Catalytic reduction:

An example of tertiary catalytic reduction is non-selective catalytic reduction (NSCR), which has the advantage of reducing both nitrogen oxides (NOx) and N2O emissions. According to the EPA guidance document, this type of control has a reduction efficiency of 80 to 95 percent. In its guidance document, EPA reports that 14 process trains in the U.S. use NSCR. These facilities have installed NSCR to control NOx emissions; and as an additional benefit, NSCR reduces N2O emissions. The guidance document states that only one U.S. plant with NSCR had emission test data which measured 0.43 pound N2O per ton of HNO3.[76]

[74] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry, p. 10.
[75] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry, p. 12.
[76] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry, p. 13.

Catalytic decomposition:

Tertiary catalytic decomposition technology achieves the decomposition of N2O to form N2 and O2 (as in secondary controls); but due to its placement following ammonia oxidation, it can achieve higher removal efficiencies for N2O than the secondary control. In addition, this technology does not require any reducing agents or additives, and no undesirable by-products are formed. The EPA guidance document reports that most tertiary catalytic decomposition controls can achieve emission rates of less than 1.0 lb of N2O per ton of HNO3.[77]

There is only one known N2O BACT determination for a nitric acid plant in the U.S., nitrogen facility in Green County, Tennessee, which proposed tertiary catalytic decomposition for control of N2O.[78] Although a GHG BACT determination was not required for the Southeast Idaho Energy project, because it received a Permit to Construct in November 2009, it included use of tertiary catalytic decomposition for N2O reduction that controlled N2O emissions to 3.4 pounds per of HNO3.[79]

The permittee proposes that the N2O emissions for the proposed nitric acid plant will be treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent converts 95 percent of the remaining N2O emission to N2 and nitric oxide.

The estimated HECA nitric acid plant uncontrolled emission rate is 11.25 pounds per hour.[80] The oxidation catalyst is expected to achieve a 95 percent reduction in N2O, resulting in a controlled emission rate of 0.54 pound N2O per ton HNO3. DOC conditions will limit emissions and require testing to ensure compliance with this limit.

Step 2: Eliminate technically infeasible options.

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77 Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry, p. 15.

78 USEPA Region IV letter to Division of Air Pollution Control Technology in Tennessee regarding U.S. Nitrogen facility, August 2011, nitric acid plant items 2 and 3.
http://www.epa.gov/nsr/ghgdocs/20110808usnitrogen.pdf

79 *Air Quality Permit to Construct Number P-2009.0127*, Southeast Idaho Energy, LLC, American Falls, Idaho. Idaho Department of Environmental Quality, November 30, 2009.
http://www.deq.idaho.gov/media/492273-se_idaho_energy_power_county_ptc_1109_statement.pdf

80 Documentation was provided by the permittee in a memo dated 8/1/12 to the SJVAPCD based on vendor estimates.

None of the controls listed in step 1 were eliminated as technically infeasible.

Step 3: Rank remaining control technologies.

Based on the controlled emission rates of N2O per ton of HNO3 produced that were discussed in step 1, the identified controls are ranked by effectiveness as follows:

1) Tertiary control (catalytic reduction or catalytic decomposition
2) Secondary control (catalytic N2O decomposition in the oxidation reactor)
3) Primary control (suppression of N2O formation)

Step 4: Evaluate most effective controls and document results.

The most effective control technology is tertiary control. The applicant proposes the use of tertiary catalytic using catalytic decomposition to reduce the N2O emissions from the nitric acid unit by 95 percent, to a controlled emission rate of 0.54 pound N2O per ton of HNO3.

This emission rate is lower than the average performance standard of the top 10 percent most efficient installations with tertiary controls (excluding units with NSCR) of 2.2 pounds N2O per ton HNO3.[81] Because of the low emission rate proposed by HECA, and the fact that the only previous nitric acid plant GHG BACT determination concluded that BACT was this same technology, the proposed BACT is believed to be the best control technology available, and no further analysis of control technologies is performed for the nitric acid plant.

Therefore, this proposal is deemed BACT for the nitric acid plant.

Step 5: Select the BACT.

The following will be required as GHG BACT for the nitric acid plant:

- Tertiary control (catalytic decomposition).

DOC conditions will require that the nitric acid be equipped with tertiary catalytic decomposition system, and conditions will limit N2O emissions. The proposed controlled N2O emission rate of 0.54 pound N2O per ton of HNO3 will be required to be tested using source test methods approved by the District to demonstrate compliance with the BACT level.

Therefore, compliance with BACT requirements is expected.

[81] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry

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G. Top Down BACT Analysis for Urea Absorber (S-7616-34-0)

Purified and compressed CO2 and liquid ammonia are reacted in the urea unit to create a concentrated urea solution, which is pumped to the urea pastillation unit.

The off-gases from the urea synthesis process, consisting of inerts (CO2, nitrogen, and water) present in the CO2 feed, process air, and unreacted ammonia are cleaned before passing through the high-pressure (HP) scrubber, which operates at an elevated pressure. The off-gases are scrubbed first with process water, and second with clean, cold water. In this way, nearly all of the ammonia is scrubbed from the gas. Low pressure off-gases are cleaned in the low-pressure (LP) scrubber, which operates at close to atmospheric pressure. Here, the off-gas is scrubbed with clean, cold water to reduce the ammonia content in the vent. Both the HP and LP absorbers are vented to the single Urea Absorber stack.

Emissions associated with the urea absorber are in the form of ammonia (which are reduced by the wet scrubber) and CO2. GHG emissions from the absorber are minor amounts of CO2, with CO2e emissions expected to be approximately 129 tons per year, which is approximately 0.02 percent of the facility total.

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. CO2 capture and recovery system
2. Implementation of good operating practices

Each of these control options and their feasibility for this project are discussed below.

1. CO2 capture and recovery system

Due to the low level of CO2 emissions, capture and recovery of the stream is not feasible. CO2 emissions from these operations are expected to be approximately 0.02 percent of the facility total.

Thus, this technology can be removed from consideration.

2. Implementation of good operating practices

Emissions of CO2 are restricted by implementing good operating practices, in order to maintain the feed stream. CO2 is a feed for the production of urea, and is therefore a valuable commodity.

Step 2: Eliminate technically infeasible options.

As is explained in Step 1, a CO2 capture and recovery system can be eliminated as technically infeasible.

Step 3: Rank remaining control options.

1. Implementation of good operating practices.

Step 4: Evaluate most effective controls and document results.

The most effective control for the reduction of GHG emissions is proposed. Therefore, there is no need to evaluate the effectiveness of these options further.

Step 5: Select BACT.

The following controls will be required as GHG BACT:

- Implementation of good operating practices.

DOC conditions will require that permittee maintain the urea absorber in good operating condition and that it be operated in a manner to minimize emissions of air contaminants into the atmosphere.

Therefore, compliance with BACT requirements is expected.

H. Top Down BACT Analysis for Ammonia Synthesis Plant Startup Heater (S-7616-33-0)

A 56.0 MMBtu/hr natural gas-fired startup heater is provided in the ammonia synthesis unit to raise the catalyst bed temperatures during initial plant commissioning, or during startup after a plant maintenance outage.

The ammonia synthesis unit also contains an ammonia refrigeration system to provide the chilling required for cooling the converter effluent stream and the ammonia product stream, and to recover and condense ammonia vapor from the ammonia storage tanks.

Operation of the ammonia synthesis plant startup heater will be limited to 7.84 billion Btu/yr, which is equivalent to 140 hr/yr at full load. In addition, the heater will only combust a lower-carbon fuel, PUC-quality natural gas. Due to the low use of this unit, add-on controls are not feasible. HECA proposes that the SJVAPCD DOC conditions reflect this limited use, and that GHG BACT for this heater be determined to be limited usage. Compliance with this limit will be demonstrated by monitoring the natural gas flow rate to the heater.

Step 1 - Identify potential control technologies

The following technologies have been identified as possible GHG emission controls for this source:

1. Intermittent use of the startup heater
2. Firing on natural gas

Each of these control options and their feasibility for this project are discussed below.

Each of these methods, and their feasibility for this project, are discussed below.

1. Intermittent use of the startup heater

Operation of the heater will be limited to 7.84 billion Btu/hr, which is equivalent to 140 hr/yr at full load.

2. Firing on natural gas

The heater will be fired on PUC-quality natural gas.

Step 2 - Eliminate technically infeasible options

None of the technologies identified in Step 1 were eliminated as technically feasible options.

Step 3 - Rank remaining options by control effectiveness

It is proposed that all of the remaining control options identified be implemented to reduce GHG emissions. Therefore, there is no need to rank the control technologies.

- Intermittent use of the startup heater
- Firing on natural gas

Step 4: Evaluate most effective controls and document results.

All of the controls identified in Step 3 are proposed as GHG BACT. Therefore, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be all of the following:

- Intermittent use of the startup heater
- Firing on natural gas

Step 5 - Select BACT

The following controls will be required as GHG BACT:

- Intermittent use of the startup heater
- Firing on natural gas

DOC conditions will limit the firing rate of the heater to 7.84 billion Btu/hr and will require that the boiler fire solely on PUC-quality natural gas.

I. Top Down BACT Analysis for Diesel-Fired Emergency IC Engines (S-7616-38-0, -39-0, and -40-0)

The applicant proposes three emergency engines for this project: two diesel-fired engines driving standby generators which are each rated 2,922 brake horsepower and one diesel-fired engine driving a fire water pump rated at 556 brake horsepower.

These emergency diesel-fired engines will emit GHG emissions (CO2, CH4, and N2O) because they combust hydrocarbon fuel. However, because their use is limited to emergency situation and routine maintenance, inspection, and testing, their total annual CO2e emissions are very small (approximately 0.06 percent of the total project CO2e emissions as shown in Table 1).

The use of diesel fuel is standard for emergency engines because it is the most reliable fuel for emergency scenarios when supplies of other fuels may be unavailable. The use of electric motors or natural gas-fired engines is not appropriate because either energy source could be interrupted in certain emergency scenarios. Therefore, the only achievable approach to reducing GHGs from the emergency generator and firewater pump engines is to limit their use, and to use efficient engines. The applicant proposes both measures.

The applicant will use new engines meeting the latest efficiency and pollutant performance standards. Specifically, regarding criteria pollutants, these standby diesel-fired engines will be required to meet the latest EPA Tier Certification level that is applicable for the horsepower range for each engine at the time of installation.

Based on the proposed emission levels, the standby firewater pump engine will be limited to no more than 100 hours per year for reliability testing and maintenance purposes. The standby electric generators will each be limited to no more than 50 hours per year of operation. This limited use will be required as DOC conditions.

Step 1: Identify all available control technologies.

Potentially applicable GHG control technologies for the emergency engines include:

1. Limited operation
2. Installation the latest EPA Tier certification level

Each of these methods, and their feasibility for this project, are discussed below.

1. Limited operation

The engines will be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. To ensure that the engines are operating properly in case of an emergency, operation of the engines for maintenance, testing, and required regulatory purposes will be limited to no more than 100 hours per calendar year for the firewater pump engine and will be limited to no more than 50 hours per calendar year for the electric generator engines.

2. Installation of the latest EPA Tier certification level

The proposed engines that are installed shall meet the latest EPA Tier certification level engine that applies for the proposed engines at the time of installation as required by the DOC.

Step 2: Eliminate technically infeasible options.

None of the controls identified in Step 1 were eliminated as technically infeasible.

Step 3: Rank remaining control technologies.

It is proposed that all of the remaining control options identified by implemented to reduce GHG emissions. Therefore, there is no need to rank the control technologies.

- Limited operation
- Installation the latest EPA Tier certification level

Step 4: Evaluate most effective controls and document results.

All of the controls identified in Step 3 are proposed as GHG BACT. Therefore, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be all of the following:

- Limited operation
- Installation the latest EPA Tier certification level

Step 5: Select the BACT.

The following controls will be required as GHG BACT:

- Limited operation
- Installation the latest EPA Tier certification level

Operation of engines will be limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 100 hours per calendar year for the firewater pump engine and not to exceed 50 hours per calendar year for the electric generator engines. BACT will also be the installation of the latest EPA Tier certification level that is applicable at the time of installation will be required.

Compliance with these requirements will be ensured with DOC conditions requiring that each engine be equipped with an hour meter, that the permittee maintain records of the operation of the engines. Conditions will also require that the engines installed be the latest EPA Tier certification levels at the time of installation.

J. Top Down BACT Analysis for Fugitive Emissions (Attributed to Units S-7616-21-0, '-23-0, and '-33-0)

It is estimated that there will be approximately 54 tons of CO2e per year of emissions from project equipment and pipe component leaks, such as pumps, valves, flanges, and compressors, after implementation of the leak detection and repair (LDAR) program, which is approximately 0.01 percent of the total facility CO2e. This emission estimate includes contributions from components in both CO2 and CH4 services, and will be approximately 0.01 percent of total facility emissions. The fugitive emissions will be associated primarily with the gasification block and the manufacturing complex, and they will be assessed to units S-7616-21-0 (gasification system), '-23-0 (sulfur recovery system), and '-33-0 (ammonia synthesis unit/fertilizer manufacturing complex).

The LDAR program will be implemented in select process areas to maximize emission reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals. LDAR will be implemented to hazardous air pollutants, VOCs, and NH3 on fugitive components in the gasification block, SRU, and manufacturing complex. These areas include streams that contain CO2 and CH4. The use of LDAR, although not specific for GHG emissions, has the secondary benefit of reducing GHG from these process units.

Because total fugitive emissions of CO2e from equipment components are so small (approximately 0.01 percent of the facility total as shown in Table 1), relative to the overall facility emissions, further control of fugitive emissions would have minimal additional benefit. It is proposed that the same LDAR program as outlined in the SJVAPCD DOC be BACT for fugitive emissions of GHG.

Step 1: Identify all available control options.

The following technologies have been identified as possible GHG emission controls for this source:

1. Leak detection and repair (LDAR) program

1. Leak detection and repair (LDAR) program

Fugitive emissions of VOC, CO, NH3, H2S, and trace hazardous air pollutants (HAPs) and greenhouse gases (GHGs) may occur in some areas of the facility due to leaks in the piping and components. Fugitive emissions are associated primarily with the gasification block and the manufacturing complex. The LDAR program will be implemented in select process areas to maximize emission

reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals.

The following process streams at the facility have been identified:

Process stream #	Description
1	Methanol
2	Syngas
3	--
4	Shifted syngas
5	Propylene
6	Sour water
7	H2S-laden methanol
8	CO2-laden methanol
9	Acid gas
10	Ammonia-laden gas
11	Sulfur
12	TGU process gas
13	Low NH3 concentration
14	Moderate NH3 concentration
15	High NH3 concentration
16	Low CO2 concentration
17	Moderate CO2 concentration
18	High CO2 concentration
18a	CO2 product and purification compressors
18b	Urea CO2 compressor
19	NO2
20	HNO3 (Nitric acid)
21	PSA off gas
22	Lower benzene concentration
23	Higher benzene concentration

The LDAR program will be implemented on a selected process areas with the largest potential fugitive VOC, toxic air contaminant (TAC), and GHG emissions: streams #1, 5, 7 through 10, and 13 through 23 (methanol, propylene, H2S-laden methanol, CO2-laden methanol, acid gas, ammonia laden gas, low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification compressors, Urea CO2 compressor, NO2, nitric acid (HNO3), PSA off gas, lower benzene concentration and higher benzene

concentration). These streams were selected because they had the largest uncontrolled emission estimates for methanol, propylene, H2S, GHG, and ammonia.

Step 2: Eliminate technically infeasible options.

None of the controls identified in Step 1 were eliminated as technically infeasible.

Step 3: Rank remaining control options.

The most effective control option for the reduction of GHG emissions is:

1. Leak detection and repair (LDAR) program

Step 4: Evaluate most effective controls and document results.

Since the only control identified in Step 3 is proposed, there is no need to evaluate the effectiveness of these options further. GHG BACT for this source will be:

- Leak detection and repair (LDAR) program

Step 5: Select BACT.

The following controls will be required as GHG BACT:

- Leak detection and repair (LDAR) program

DOC conditions will require that process streams identified in Step 1 (methanol, propylene, H2S-laden methanol, CO2-laden methanol, acid gas, ammonia laden gas, low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification compressors, Urea CO2 compressor, NO2, nitric acid (HNO3), PSA off gas, lower benzene concentration and higher benzene concentration) be subject to the LDAR program.

Therefore, compliance with BACT requirements is expected.

K. Top Down BACT Analysis for Circuit Breakers (not subject to District permit requirements)

The facility's circuit breakers will have the potential to emit a very small amount of GHG, in the form of sulfur hexafluoride (SF6). Circuit breakers do not emit SF6 directly, but they do have the potential for fugitive emissions (leaks). The proposed project site will include a switchyard with approximately 8 circuit breakers, with a total SF6 inventory of approximately 1,600 pounds (less than 1 ton) of SF6 in the enclosed-pressure breakers according to the applicant. SF6 is a gaseous dielectric used in the breakers. Leakage is expected to be minimal. Even assuming a 0.5 percent annual leak rate, its potential emissions are equivalent to 95 tons per year CO2e, which is less than 0.01 percent of the facility total CO2e (as shown in Table 1). Nevertheless, this small source has been considered for purposes of this GHG BACT analysis.

Step 1: Identify all available control technologies.

Potentially applicable GHG control technologies considered for the circuit breakers include:

1. Use of state-of-the art circuit breakers that use SF6 technology with a leak detection system
2. Use of non-GHG dielectric material in the circuit breakers.

Each of these methods, and their feasibility for this project, are discussed below.

1. Use state-of-the-art circuit breakers using SF6 technology with a leak detection system

A proposed alternative is to use state-of-the-art SF6 technology with leak detection to limit fugitive emissions. In comparison to older SF6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5 percent per year (by weight). This leak rate meets the current maximum leak rate standard established by the International Electrotechnical Commission.[82]

In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10 percent of the SF6 (by weight) has escaped. The use of an alarm identifies potential leak

[82] The IEC standard identifying the maximum allowable leakage rate of 0.5 percent per year came from the IEC standard 62271-1. That standard is summarized in this summary provided by USEPA: http://www.epa.gov/electricpower-sf6/documents/conf06_blackman.pdf

problems before the bulk of the SF6 has escaped, so that it can be addressed proactively to prevent further release of the gas and maintain the insulation value in the circuit breakers.

The use of enclosed-pressure SF6 circuit breakers with leak detection is feasible for this location. HECA has proposed to use this equipment because of its performance benefits.

2. Use a non-GHG dielectric material in the circuit breakers

Another alternative is to substitute another, non-GHG substance for SF6 as the dielectric material in the breakers. One alternative available is the use of a dielectric oil or compressed air ("air blast") circuit breaker, which historically were used in high-voltage installations prior to the development of SF6 breakers. This type of technology is feasible, although SF6 has become the predominant insulator and arc-quenching substance in circuit breakers today because of its superior capabilities.

This type of circuit breaker would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF6 breakers. The larger oil/air-blast breakers would require that additional land be devoted to the project, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires.

Although oil/air-blast breakers are theoretically feasible, they are not preferred versus the choice of SF6 breakers because of their negative characteristics and the fact that the use of the latest SF6 breakers only results in very small GHG emissions. This conclusion is supported by the most recent report released by the USEPA SF6 Partnership, which states: "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switchgear, due to its inertness and dielectric properties."[83] Research and development efforts have focused on finding substitutes for SF6 that have comparable insulating and arc-quenching properties in high-voltage applications.[84] Although some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded "that there is no

[83] *SF6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*, December 2008, p. 1, www.epa.gov/electricpower-sf6 .

[84] See National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*, November 1997; http://www.epa.gov/electricpowersf6/documents/new_report_final.pdf. See also U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF6," http://www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf

replacement gas immediately available to use as an SF6 substitute"[85] for high-voltage applications.

Step 2: Eliminate technically infeasible options.

None of the controls identified in Step 1 were eliminated as technically infeasible.

Step 3: Rank remaining control technologies.

The most effective remaining control options for the reduction of GHG emissions are listed below in the order of effectiveness:

1. Use of non-GHG dielectric material in the circuit breakers
2. Use of state-of-the art circuit breakers that use SF6 technology with a leak detection system

Step 4: Evaluate most effective controls and document results.

Although there is minimal reduction in GHG emissions from the use of non-GHG dielectric material circuit breakers over modern circuit breakers, the negative characteristics of the circuit breaker that use non-GHG dielectric material (as described in Step 1) and the minimal reduction in GHG emissions, the applicant's proposal to use modern circuit breakers that use SF6 technology along with a leak detection system is determined to be the most effective control. Thus, state-of-the art SF6 technology with a leak detection system will be the most effective GHG control for the circuit breakers in this project.

Step 5: Select the BACT.

The following controls will be required as GHG BACT:

- Use of state-of-the art circuit breakers that use SF6 technology with a leak detection system

DOC conditions will require the use of state-of-the-art SF6 technology circuit breakers with a leak detection system.

[85] T. Olsen (Manager, Siemens Power Transmission & Distribution), Siemens Electrical Distribution Products Catalog 2006, "Medium Voltage Equipment: Special Applications & Technical Information," at 13-29 (summarizing the results of the NIST study referenced in the preceding footnote), http://www.sea.siemens.com/SpeedFax06/Speedfax06files/06Speedfaxpdfs/06Speedfax_13/13_28-29.pdf .

VI. BACT Determination Summary

Table 7 below summarizes the BACT proposed as a result of this GHG BACT analysis. The proposed project was designed to minimize GHG emissions. This is done primarily through the capture of 90 percent of the carbon in the raw syngas in a high-purity CO2 stream for use in EOR and subsequent sequestration. This ensures that a low-carbon fuel is used as the basis for generation of nitrogen-based fertilizers and electric power. Also, many additional design features have been implemented that conserve and reuse thermal energy, and in so doing, reduce GHG emissions from the proposed project.

Table 7: Summary of Proposed GHG BACT Limits for HECA		
Emission Source	**Proposed GHG BACT controls**	**Compliance with GHG BACT controls demonstration method**
HECA Project (Entire Facility)	• Energy-efficient facility design, plus controls listed below.	The facility CO2e potential emissions will be limited to 593,965 tons-CO2e/yr. The permittee will be required to monitor the facility's CO2e and maintain such records onsite.
Combustion Turbine Generator (S-7616-26-0)	• Capture of 90% of the pre-combustion CO2 through carbon sequestration and firing on hydrogen-rich fuel • Energy-efficient turbine design • Firing on PUC-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages	DOC conditions will require that the capture of 90 percent of the pre-combustion CO2 through carbon sequestration shall be demonstrated by monitoring the flow rate and carbon content in the captured CO2 stream and the flow and carbon content of the hydrogen-rich fuel combusted in the CTG/HRSG. The installation of proposed energy-efficient turbine model will be specified on the DOC. Additionally, firing on PUC-quality natural gas will be required as backup fuel, and such operation will be limited to startups, shutdowns, and unplanned equipment outages.
CO2 Recovery and Vent System (S-7616-24-0)	• Capture, compression, and transportation of the CO2 stream in a pipeline for injection (during normal operation); venting of CO2 stream when injection system is unavailable due to upset condition with such cumulative periods not exceeding 504 hours (or its equivalent flowrate) per rolling 12-month period, which is equivalent to 193,394 tons per year of CO2; and the use of good operating practices on the CO2 and transportation system.	DOC conditions will limit the venting only to periods when the compression and transportation system is unavailable or CO2 delivery system is unavailable due to cold gasification block startup, CO2 compressor unplanned outage, CO2 pipeline unplanned outage, or CO2 off-taker unable to accept, and such venting shall not exceed 504 hours (or its equivalent flowrate of 193,394 tons of CO2) per rolling 12-month period. Additionally, the daily flow rate of the CO2 vent will be limited through the use of daily emission limits for CO, CO2 and VOC. Compliance with the limits shall be monitored with a non-resettable, totalizing mass or volumetric flow measure and through speciated vent stream composition source tests required upon startup and during each venting occurrence exceeding 500,000 scf/day.

Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)	• Limited operation (annual fuel firing rate limited to 466 billion Btu per year) • Firing on a lower-carbon fuel (PUC-quality natural gas) • Energy-efficiency measures (economizer and condensate recovery) • Tuning the boiler twice per calendar year	DOC conditions will require that the boiler be fired solely on PUC-quality natural gas and that it be equipped with an economizer and a condensate recovery system. The boiler shall also be required to be equipped with a fuel flow meter and will require recordkeeping to demonstrate compliance with the annual fuel firing rate limit of 466 billion Btu per year. Conditions will also require that the boiler be tuned twice per calendar year.
Nitric Acid Unit (S-7616-35-0)	• Tertiary control (catalytic decomposition) and N2O emission rate limited to 0.54 lb-N2O/ton of HNO3 produced	DOC conditions will require that the nitric acid be equipped with tertiary catalytic decomposition system, and conditions will limit N2O emissions. The proposed controlled N2O emission rate of 0.54 pound N2O per ton of HNO3 produced will be required to be tested to demonstrate compliance with the BACT level.
Tail Gas Thermal Oxidizer (S-7616-23-0)	• Firing on PUC-quality natural gas • Sulfur recovery unit startup venting limited to 48 hours per calendar year and shutdown limited to 24 hours per year	DOC conditions will require that the unit be fired solely on PUC-quality natural gas, that venting from SRU startups to be limited to 3,840 MMBtu per calendar year and maintenance limited to 1.920 MMBtu per calendar year, and that the fuel flow rate to the thermal oxidizer be monitored.
Flares (S-7616-30-0, -31-0, -32-0)	• Minimization of flaring and the preparation of a flare minimization plan. • Limited venting	DOC conditions will limit the planned flaring as follows: • Gasification block flare: 74,914 MMBtu per year (21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; and 43,434 MMBtu/yr of shifted gas); • Sulfur recovery unit flare: 2,628 MMBtu/yr during pilot gas combustion and 1,440 MMBtu/yr during other non-emergency combustion for startups and shutdowns; • Rectisol unit flare: 430 MMBtu/hr of natural gas assist for 40 hours per year during startups and shutdowns. A flare minimization plan will be required for each flare to limit the GHG emissions.

Ammonia Synthesis Plant Startup Heater (S-7616-33-0)	• Intermittent use of the startup heater (annual firing rate limited to 7.84 billion Btu/yr) • Firing on PUC-quality natural gas	DOC conditions will limit the firing rate of the heater to 7.84 billion Btu/yr and will require that the boiler fire solely on PUC-quality natural gas.
Urea Absorbers (S-7616-34-0)	• Implementation of good operating practices.	DOC conditions will require that permittee maintain the urea absorbers in good operating condition and that it be operated in a manner to minimize emissions of air contaminants into the atmosphere.
Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0)	• Limited operation (limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 50 hours per calendar year) • Installation the latest EPA Tier certification level	Operation of engines will be limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 50 hours per calendar year for the electric generator engines. BACT will also be the installation of the latest EPA Tier certification level that is applicable at the time of installation will be required.
Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0)	• Limited operation (limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 100 hours per calendar year) • Installation the latest EPA Tier certification level	Operation of engine will be limited to emergencies and during maintenance, testing, and required regulatory purposes not to exceed 100 hours per calendar year for the firewater pump engine. BACT will also be the installation of the latest EPA Tier certification level that is applicable at the time of installation will be required.
Fugitive Emissions - Gasification Block and Manufacturing Complex (included on permits S-7616-21, -23 and -33)	• Leak detection and repair (LDAR) program	Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: methanol, propylene, H2S-laden methanol, CO2-laden methanol, acid gas, ammonia laden gas, low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO2 concentration, moderate CO2 concentration, high CO2 concentration, CO2 product and purification Compressors, Urea CO2 compressor, NO2, nitric acid (HNO3), PSA off gas, lower benzene concentration, and higher benzene concentration.
Circuit Breakers (conditions will be included on DOC S-7616-26)	• Use of state-of-the art circuit breakers that use SF6 technology with a leak detection system	DOC conditions will require the use of state-of-the-art SF6 technology circuit breakers with a leak detection system.

APPENDIX I-A
FACILITY CO2e CALCULATIONS

GHG Emissions Summary of Stationary Sources — Emissions Summary

Hydrogen Energy California LLC — *11/1/2012*
HECA Project — *Updated 6/30/2013*

GHG emissions are numerically depicted as metric tons (tonne) of carbon dioxide equivalents (CO_2e). CO_2e represents CO_2 plus the additional

Natural Gas GHG Emission Factors						Diesel GHG Emission Factors				
CO_2 =	53.06	kg/MMBtu =	116.98	lb/MMBtu		CO_2 =	10.15	kg/gal =	22.38	lb/gal
CH_4 =	0.001	kg/MMBtu =	0.0022	lb/MMBtu		CH_4 =	0.0004	kg/gal =	0.001	lb/gal
N_2O =	0.0001	kg/MMBtu =	0.00022	lb/MMBtu		N_2O =	0.0001	kg/gal =	0.0002	lb/gal

CO_2, CH_4, and N_2O emission factors are taken from Appendix C of the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (Jan 2009)

Combustion Turbine Generator (S-7616-26-0)
Turbine - Burning Hydrogen-Rich Fuel - released to HRSG and Coal Dryer Stacks

					Syngas GHG Emission Factors *		
Operating Hours	8012	hr/yr			CO_2 =	17.7	lb/MMBtu
Heat Input (HHV)	2,537	MMBtu/hr			CH_4 =	0.03	lb/MMBtu
CO_2 =	163,272	tonne/yr			* Based on composition of syngas		
CH_4 =	288	tonne/yr =	6,044	tonne CO_2e/yr			
N_2O =	2.03	tonne/yr =	630	tonne CO_2e/yr	Total tonne CO_2e/yr =		169,946

HRSG heat input rate is based Case 5, average ambient temperature and peak load.

Operating hours include startup and shutdown operations

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Combustion Turbine Generator (S-7616-26-0)
Duct burner - Burning Hydrogen-Rich Fuel - released to HRSG and Coal Dryer Stacks

					Syngas GHG Emission Factors		
Operating Hours	8000	hr/yr			CO_2 =	17.7	lb/MMBtu
Heat Input (HHV)	165	MMBtu/hr			CH_4 =	0.03	lb/MMBtu
CO_2 =	10,603	tonne/yr			* Based on composition of syngas		
CH_4 =	19	tonne/yr =	393	tonne CO_2e/yr			
N_2O =	0.13	tonne/yr =	41	tonne CO_2e/yr	Total tonne CO_2e/yr =		11,036

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Combustion Turbine Generator (S-7616-26-0)
Duct burner - Burning PSA Offgas - released to HRSG and Coal Dryer Stacks

					PSA Offgas GHG Emission Factors **		
Operating Hours	8,000	hr/yr			CO_2 =	153.6	lb/MMBtu
Heat Input (HHV)	149	MMBtu/hr			CH_4 =	0.3	lb/MMBtu
CO_2 =	83,053	tonne/yr			** Based on composition of PSA offgas		
CH_4 =	146	tonne/yr =	3,073	tonne CO_2e/yr			
N_2O =	0.12	tonne/yr =	37	tonne CO_2e/yr	Total tonne CO_2e/yr =		86,163

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Combustion Turbine Generator (S-7616-26-0)
Turbine - Burning Natural Gas - released to HRSG Stack

Operating Hours	351	hr/yr
Heat Input (HHV)	2,401	MMBtu/hr

CO_2 =	44,729	tonne/yr				
CH_4 =	0.84	tonne/yr =	18	tonne CO_2e/yr		
N_2O =	0.08	tonne/yr =	26	tonne CO_2e/yr	Total tonne CO_2e/yr =	44,772

HRSG heat input rate is assumed to be the maximum heat input rate firing natural gas. Hours of operation include startup and shutdown.

Tail Gas Thermal Oxidizer (S-7616-23-0)

Process Vent Disposal Emissions

Operating Hours	8,314	hr/yr
Heat Input	13	MMBtu/hr

CO_2 =	5,736	tonne/yr				
CH_4 =	0.11	tonne/yr =	2.3	tonne CO_2e/yr		
N_2O =	0.0108	tonne/yr =	3.4	tonne CO_2e/yr	Total tonne CO_2e/yr =	5,742

SRU Startup Waste Gas Disposal

Operating Hours	72	hr/yr
Heat Input	80	MMBtu/hr

CO_2 =	306	tonne/yr				
CH_4 =	0.006	tonne/yr =	0.12	tonne CO_2e/yr		
N_2O =	0.00058	tonne/yr =	0.179	tonne CO_2e/yr	Total tonne CO_2e/yr =	306

GHG emissions from thermal oxidizer are estimated using GHG emission factors for natural gas combustion for the assist gas.

CO_2 Recovery and Vent System (S-7616-24-0)

Operating Hours	504	hr/yr
CO_2 Emission Rate	761,400	lb/hr

Total tonne CO_2e/yr =	174,113

Assumes 504 hours per year venting at full rate.

Natural Gas-Fired Auxiliary Boiler (S-7616-25-0)

Operating Hours	2,188	hr/yr *	* 466 billion Btu/hr / 213 MMBtu/hr = 2188 hr/yr
Heat Input	213	MMBtu/hr	

CO_2 =	24,733	tonne/yr				
CH_4 =	0	tonne/yr =	10	tonne CO_2e/yr		
N_2O =	0.05	tonne/yr =	14	tonne CO_2e/yr	Total tonne CO_2e/yr =	24,757

Gasification Flare (S-7616-30-0)

Pilot Operation

Operating Hours	8,760	hr/yr	
Heat Input	0.5	MMBtu/hr	natural gas pilot

CO_2 =	232	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0004	tonne/yr =	0.1	tonne CO_2e/yr	Total tonne CO_2e/yr =	233

Flaring Events

Total Operation	70,534	MMBtu/yr	(Total operation = NG startup + Unshifted syngas startup + Shifted syngas startup + Shifted syngas shutdown) =17556+9544+24130+19304 70534

CO_2 =	3,744	tonne/yr				
CH_4 =	0.1	tonne/yr =	1	tonne CO_2e/yr		
N_2O =	0.01	tonne/yr =	2	tonne CO_2e/yr	Total tonne CO_2e/yr =	3,747

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

SRU Flare (S-7616-31-0)						
Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr	natural gas pilot		
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events - natural gas assist for acid gas venting during startup						
Operating Hours		40	hr/yr			
Heat Input		36	MMBtu/hr			
Throughput (inerts) - acid gas venting during startup						
CO_2 =		140000	scf/hr			
CO_2 =		16,240	lb/hr			
CO_2 =	371	tonne/yr				
CH_4 =	0.001	tonne/yr =	0.03	tonne CO_2e/yr		
N_2O =	0.00014	tonne/yr =	0.045	tonne CO_2e/yr	Total tonne CO_2e/yr =	371
Throughtput (inerts) provided from design engineers.						

Rectisol Flare (S-7616-32-0)						
Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr	natural gas pilot		
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events						
Operating Hours		40	hr/yr			
Vent gas flow		4542	lb-mole/hr			
CO_2 =	3,627	tonne/yr				
CH_4 =		tonne/yr =		tonne CO_2e/yr		
N_2O =		tonne/yr =		tonne CO_2e/yr	Total tonne CO_2e/yr =	3,627
GHG emissions from flaring event based on 100% carbon content of the gas during startup.						

Ammonia Synthesis Plant Startup Heater (S-7616-33-0)						
Operating Hours		140	hr/yr	=7.84 billion Btu/yr / 56 MMBtu/yr = 140 hr/yr		
Heat Input		56	MMBtu/hr			
CO_2 =	416	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	0.00	tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	417

Urea Absorbers (S-7616-34-0)						
Operating Hours		8,052	hr/yr			
CO_2		32	lb/hour			
CO_2 =	117	tonne/yr				
CH_4 =		tonne/yr =	0	tonne CO_2e/yr		
N_2O =		tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	117
Emission rate provided by project engineers.						

Nitric Acid Unit (S-7616-35-0)						
Operating Hours		8,052	hr/yr			
N_2O uncontrolled		10.78	lb/ton NHO3			
Production rate		501	ton/day			
N_2O uncontrolled		225	lb/hour			
destruction efficiency		95	%			
N_2O controlled		11.25	lb/hour			
CO_2 =		tonne/yr				
CH_4 =		tonne/yr =	0	tonne CO_2e/yr		
N_2O =	41	tonne/yr =	12,741	tonne CO_2e/yr	Total tonne CO_2e/yr =	12,741
Emission factor and destruction efficiency provided by design engineer.						

Diesel-Fired Emergency Engines Powering Electrical Generators (S-7616-38-0 and -39-0)						
Operating Hours		100	hr/yr	* 50 hr/yr/engine x 2 engines		
Heat Input		2,922	Bhp			
CO_2 =	3,341	lb/hr =	152	tonne CO_2/yr		
CH_4 =	0.13	lb/hr =	0.125	tonne CO_2e/yr		
N_2O =	0.03	lb/hr =	0.4630	tonne CO_2e/yr	Total tonne CO_2e/yr* =	304
The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.						
* Total tonnes CO_2e per year represent the contributions from both generators.						

Diesel-Fired Emergency Engine Powering Firewater Pump (S-7616-40-0)						
Operating Hours		100	hr/yr			
Heat Input		556	Bhp			
CO_2 =	636	lb/hr =	29	tonne CO_2/yr		
CH_4 =	0.03	lb/hr =	0.024	tonne CO_2e/yr		
N_2O =	0.01	lb/hr =	0.0881	tonne CO_2e/yr	Total tonne CO_2e/yr =	29
The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.						

Fugitives - Gasification System and SRU System (S-7616-21-0 and -23-0)						
Operating Hours		8,760	hr/yr			
CO_2 =	39.2	tpy	38.10	tonne CO_2e/yr		
CH_4 =	0.27	tpy	5.55	tonne CO_2e/yr		
					Total tonne CO_2e/yr =	44
Detailed emission calculations are provided in Appendix M, Public Health.						

Fugitives - Fertilizer Manufacturing Complex (S-7616-33-0)						
Operating Hours		8,760	hr/yr			
CO_2 =	4.7	tpy	4.53	tonne CO_2e/yr		
CH_4 =	0.04	tpy	0.91	tonne CO_2e/yr		
					Total tonne CO_2e/yr =	5
Detailed emission calculations are provided in Appendix M, Public Health.						

230 kV Circuit Breakers

Number of Circuit Breaker	6	
SF_6 capacity	240	lb/breaker

Annual Leakage rate		0.5%				
SF_6 =	0.003	tonne/yr =	78	tonne CO_2e/yr	Total tonne CO_2e/yr =	78

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

18 kV Circuit Breakers

Number of Circuit Breaker		2				
SF_6 capacity		73	lb/breaker			
Annual Leakage rate		0.5%				
SF_6 =	0.000	tonne/yr =	8	tonne CO_2e/yr	Total tonne CO_2e/yr =	8

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

Total tonne CO_2e/yr for Stationary Sources=	**538,837**

APPENDIX J
Notification of Federal Land Managers

Re: HECA Application (Kern County, California) Nearest NPS Class I area is Sequoia NP 120 km away

Tonnie_Cummings to: Cleveland Holladay 07/23/2012 02:43 PM
Cc: Judy_Rocchio, Annie_Esperanza

Cleveland Holladay	HECA Application (Kern County, California) Nearest NPS Class I area is Seq
Tonnie_Cummings	*Hi Cleve-- Hope you're doing well.*

Hi Cleve--

Hope you're doing well.

Thanks for the opportunity to review Hydrogen Energy California's (HECA) application to construct an Integrated Gasification Combined-Cycle polygeneration project west of Bakersfield. According to the application, proposed emissions are: 164 TPY NOx, 275 TPY CO, 90 TPY PM10, 80 TPY PM2.5, 35 TPY VOC and 29 TPY SO2. Given that the Q/D for Sequoia NP is 3, and that all NOx, VOC, SO2 and PM10 emissions will be offset, we do not expect the HECA project to substantially affect air quality at the park. Therefore, the NPS does not intend to provide formal comments on the application.

--Tonnie

Tonnie Cummings
Air Resources Specialist
National Park Service, Pacific West Region
612 E. Reserve Street
Vancouver, WA 98661
Phone: 360-816-6201
Fax: 360-816-6365
Email: Tonnie_Cummings@nps.gov

Cleveland Holladay <Holladay.Clevelan d@epamail.epa.gov>	Tonnie_Cummings@nps.gov	To
		cc
07/20/2012 02:44 PM	HECA Application (Kern County, California) Nearest NPS Class I area is Sequoia NP 120 km away	Subject

RE: HECA Application
McCorison, Mike -FS
to:
Cleveland Holladay
08/02/2012 03:44 PM
Cc:
"Worn, Katherine -FS", "Procter, Trent -FS", "Delgado, Arturo -FS", "Nick, Andrea -FS"
Hide Details
From: "McCorison, Mike -FS" <mmccorison@fs.fed.us>
To: Cleveland Holladay/R9/USEPA/US@EPA,
Cc: "Worn, Katherine -FS" <kworn@fs.fed.us>, "Procter, Trent -FS" <tprocter@fs.fed.us>, "Delgado, Arturo -FS" <adelgado@fs.fed.us>, "Nick, Andrea -FS" <anick@fs.fed.us>

Cleveland,
Thank you for making this application available to us. We understand that this application is being filed because of change in plant ownership. We've reviewed the application you made available and feel that our cited remarks "that a revised San Rafael AQRV analysis will not be necessary for this project" are still valid.

Thank you

Mike Mc Corison
Air Resource Specialist
Angeles National Forest
office 626-574-5286
cell 626-437-0624

From: Cleveland Holladay [mailto:Holladay.Cleveland@epamail.epa.gov]
Sent: Friday, July 20, 2012 2:30 PM
To: McCorison, Mike -FS
Subject: HECA Application

Mike,

I have uploaded the Hydrogen Energy California, LLC (HECA) PSD application for your information and comment. The HECA project will be located near the unincorporated community of Tubman in western Kern County, California. The closest US Forest Service Class I areas to the project are the San Rafael WA at 60 km to the southwest and Domelands WA 105 km to the east.

The applicant states in Section 6.2.1 at the bottom of the first paragraph that "On April 18, 2012, the U.S. Forest Service confirmed that a revised AQRV analysis would not be required for the HECA Project.

You may access the uploaded information by going to google docs and logging into [redacted] Password is [redacted] You go to google.com first and then to documents which is in the bottom row (images,gmail, more etc. are along that row too)but above google logo. There should then be a log-in page where you can copy in [redacted] then the password.

Let me know if you have further comments or need addtional information.

Thanks,

APPENDIX K
Ambient Air Quality Impact and Health Risk Report

San Joaquin Valley
Air Pollution Control District

District Rule 2201, ***New Source Review (NSR)*** &
District Rule 4201, ***Nuisance*** &
District Rule 2410, ***Prevention of Significant Deterioration (PSD)***

Ambient Air Quality Impact
&
Health Risk Assessment Report

For

Hydrogen Energy California LLC
Region S – 7616
Project #S-1121903

July 2013

Prepared by

Permit Services Department
Technical Services

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Acronyms & Abbreviations

AAQIR	Ambient Air Quality Impact Report
ACC	Air Cooled Condenser
Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
Agency	U.S. Environmental Protection Agency
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BDT	Bone Dry Tons
BTU	British thermal units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CBI	Confidential Business Information
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
District	San Joaquin Valley Air Pollution Control District
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FLM	Federal Land Manager
FWS	U.S. Fish and Wildlife Service
GAQM	40 CFR part 51, Appendix W- ***Guideline on Air Quality Models***
GEP	Good Engineering Practice
hp	Horsepower
HRSG	Heat Recovery Steam Generator
kW	Kilowatt
m	Meter
MMBTU	Million British Thermal Units
MW	Megawatts of Electrical Power
NAAQS	National Ambient Air Quality Standards
NLCD92	USGS 1992 National Land Cover
NO	Nitrogen Oxide or Nitric Oxide
NO2	Nitrogen Dioxide
NOx	Oxides of Nitrogen (NO + NO2)
NP	National Park
NSPS	New Source Performance Standards, 40 CFR part 60
NSR	New Source Review
PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 micrometers (µm) in diameter
PM_{10}	Particulate Matter less than 10 micrometers (µm) in diameter
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RBLC	U.S. EPA RACT/BACT/LAER Information Clearinghouse
SJVAPCD	San Joaquin Valley Air Pollution Control District
SCFM	Standard Cubic Feet per Minute
SIA	Significant Impact Area

SIL	Significant Impact Level
SO2	Sulfur Dioxide
SOx	Oxides of Sulfur
tpy	tons per year
USGS	United States Geological Survey
WA	Wilderness Area

Executive Summary

Hydrogen Energy California LLC (HECA LLC) has submitted an application to San Joaquin Valley Air Pollution Control District (SJVAPCD) for Determination of Compliance (DOC) for an Integrated Gasification Combined-Cycle (IGCC) polygeneration project (hereafter referred to as HECA or the Project). As described below, the proposed Project will be classified as a Major facility, as this term is defined in District Rule 2201; and a Major Stationary Source under District Rule 2410.

The HECA site will be approximately 7 miles west of the outermost edge of the City of Bakersfield, and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California. The legal description is as follows: Section 10 of Township 30 South, Range 24 East, in Kern County. The associated Assessor's Parcel Numbers (APNs) for the Project site are as follows:

- Part of 159-040-02,
- Part of 159-040-16, and
- Part of 159-040-18.

HECA is also acquiring an additional 653 acres of land adjacent to the Project Site, herein referred to as "Controlled Area." HECA LLC will own this property, and have control over public access and future land use by erecting a physical fence around the property. For the purposes of the Air Quality analysis, impacts were determined outside of both the Project Site and the Controlled Area. The associated APNs of the Controlled Area are as follows:

- 159-040-04,
- 159-040-11,
- 159-040-17,
- 159-190-09,
- Remnant part of 159-040-02,
- Remnant part of 159-040-16, and
- Remnant part of 159-040-18.

The proposed DOC application is consistent with the requirements of District Rules 2201, 4201, and 2410 for the following reasons:

- The proposed emission limits will not cause or contribute to any exceedance of the National Ambient Air Quality Standards (NAAQS) for NO2, SO2, CO, PM10, and PM2.5. There is no NAAQS set for Total Particulate Matter (PM);

- The proposed emission limits will not cause or contribute to any exceedance of the California Ambient Air Quality Standards (CAAQS) for NO2, SO2, CO, PM10, and PM2.5. There is no CAAQS set for Total Particulate Matter (PM);

- The facility will not adversely impact soils and vegetation, or air quality, visibility, and deposition in Class I areas, which are parks or wilderness areas given special protection under the Clean Air Act (CAA);

- The facility's toxic emissions will not cause an impact above the District's significant threshold level of 10 in one million or 1.0 for either the Acute or Chronic Hazard Indices.

1 Purpose of this Document

This document serves as the Ambient Air Quality Impact and Health Risk Assessment Report for the proposed construction DOC of the HECA facility. This document describes the basis for the proposed modeling, including requirements under the District's Rule 2201 New Source Review and District Rule 4201Nuisance and/or District Rule 2410 Prevention of Significant Deterioration.

2 Applicant

- **Project Site Location:**
  Hydrogen Energy California, LLC
  Section 10 Township 30S Range 24E
  Kern County, California

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3 Project Location

The HECA facility is located approximately 7 miles west of the outermost edge of the City of Bakersfield, and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California. The legal description is as follows: Section 10 of Township 30 South, Range 24 East, in Kern County. The facility is bordered on the north by Adohr Road, on the east by Tupman Road, on the south by the California Aqueduct and State Route (SR) 273, and on the west by agricultural parcels. The city of Tupman is located within the jurisdiction of the San Joaquin Valley Air pollution Control District (SJVAPCD).

The map on the following page shows the approximate location of the proposed project.

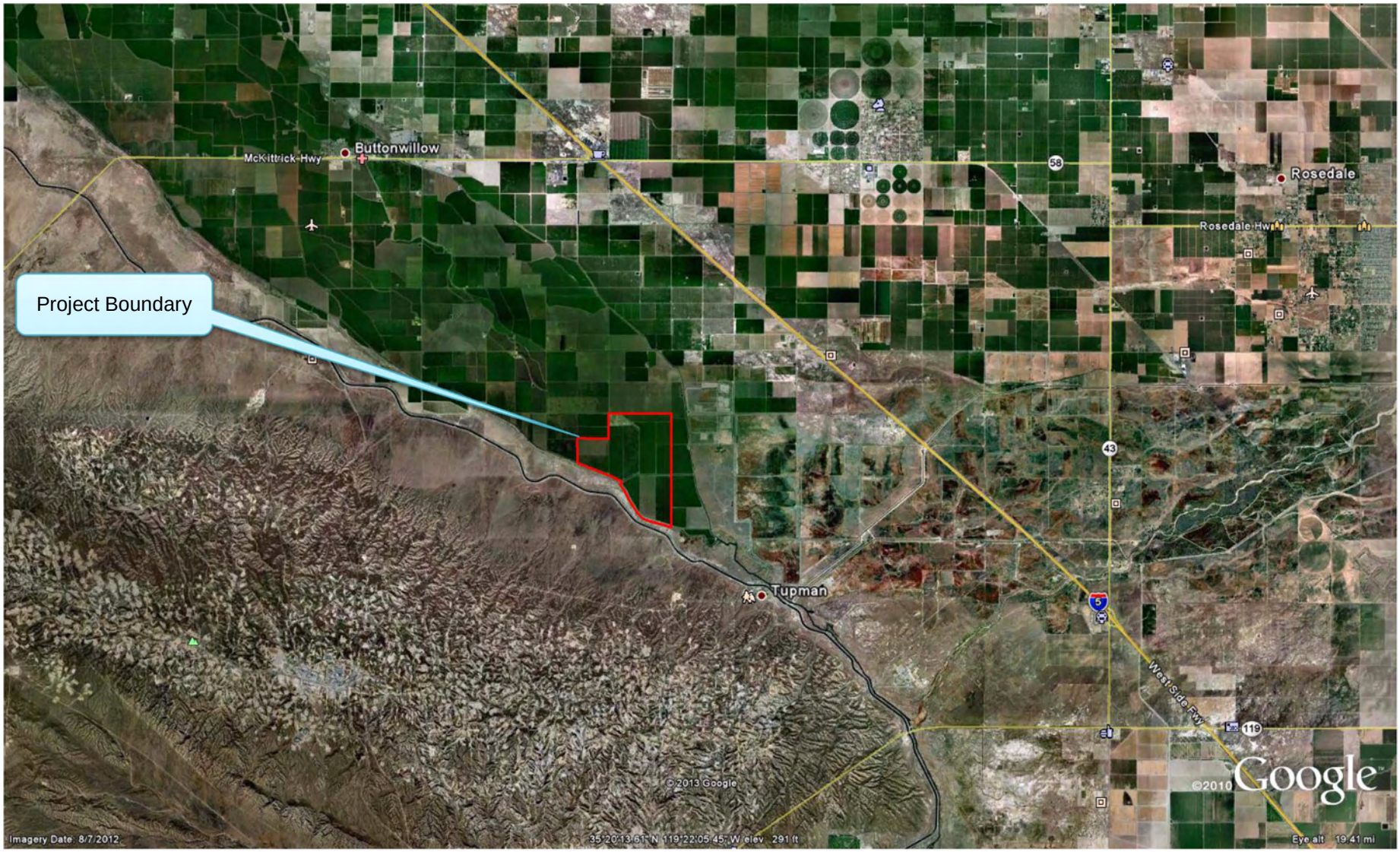


Figure 3-1 Facility Location

4 Project Description

This application is for an Integrated Gasification Combined-Cycle (IGCC) polygeneration operation and a low-carbon nitrogen-based products manufacturing operation. The Project will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen rich fuel, which will be used to generate low-carbon base load electricity in a combined cycle power block, low-carbon nitrogen-based products in an integrated manufacturing complex, and carbon dioxide (CO2) for use in enhanced oil recovery (EOR) at a neighboring oil production field.

HECA has proposed to employ the most stringent emissions control equipment available for the types of processes and equipment that will comprise the Project, and will fully offset its emissions of nonattainment pollutants and their precursors. In addition, the Project's methods for production of electric power and nitrogen-based products will have a significantly lower carbon footprint than would be possible using traditional processes based on fossil fuel. This low-carbon footprint is accomplished by capturing more than 90 percent of the carbon in the syngas and transporting it as CO2 for use in enhanced oil recovery (EOR), which results in simultaneous sequestration of this gas stream in a secure geological formation. The location of this sequestration will be the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). The OEHI EOR Project will be separately permitted by OEHI through the appropriate state agency, and SJVAPCD. Accordingly, equipment and emissions associated with EOR at the OEHI site are not addressed in this application.

4.1 New Permitted Equipment

The following is a cross-walk table that provides a basic listing of the proposed units from the permit application and the proposed District Permit IDs.

Applicant Proposed Unit ID[2]	Applicant Process Name	District Permit ID[1]	District Unit Description
1	Combined Cycle Combustion Turbine	26-0	Combustion Turbine Generator
2	Feedstock Dryer		
3	Auxiliary Boiler	25-0	NG Fired Auxiliary Boiler
4	Power Block Cooling Tower	29-0	Cooling Tower Serving Power Block
5	Process Cooling Tower	27-0	Cooling Tower Serving Power Block and Process Units
6	Air Separation Unit Cooling Tower	28-0	Cooling Tower Serving Air Separation Unit
7	Gasification Flare	30-0	Gasification Flare
8	Rectisol Flare	32-0	Rectisol Flare
9	SRU Flare	31-0	SRU Flare
10	Tail Gas Thermal Oxidizer	23-0	Sulfur Recovery System's Tail Gas Thermal Oxidizer

Applicant Proposed Unit ID[2]	Applicant Process Name	District Permit ID[1]	District Unit Description
11	CO2 Vent	24-0	CO2 Recovery and Vent System
12	Standby Diesel Generator 1	38-0	Diesel-Fired Emergency Engine Powering Electrical Generator
13	Standby Diesel Generator 2	39-0	Diesel-Fired Emergency Engine Powering Electrical Generator
14	Firewater Pump	40-0	Diesel-Fired Emergency Engine Powering Firewater Pump
15	Ammonia Start-Up Heater	33-0	Ammonia Synthesis Plant
16	Nitric Acid Unit	35-0	Nitric Acid Unit
17	Urea Pastillation Unit	34-0	Urea Unit
18	Ammonium Nitrate Unit	36-0	Ammonium Nitrate Unit
19	Dry material handling system	17-0	Coal Handling
		18-0	Petcoke Handling
	Fugitive emissions	19-0	Rec. & Blending
		20-0	Grinding
		21-0	Gasification System
		22-0	Gasification Solid Handling
		23-0	Sulfur Recovery Unit
		37-0	Urea Storage and Handling Operation

1 - The District Permit IDs start at unit 17-0 as units from the previous application have been cancelled.
2 - From Section 3.1 of the Permit Application documentation

4.2 Existing Permitted Equipment

No permitted units exist at this facility; therefore this analysis will only consider the proposed equipment from the Project's permit application.

5 SJVAPCD Attainment Status

District rules are intended to address issues of air quality in attainment and non-attainment areas, attainment areas are areas that meet the National Ambient Air Quality Standards (NAAQS). Table 5-1 describes which pollutants are covered specifically by District Rules 2201/4201 and/or 2410 within the San Joaquin Valley air basin.

Table 5-1 CAAQS/NAAQS Attainment Status for SJVAPCD

Pollutant		Attainment Status		District Rule
		Federal	State	
Lead (Pb)		No Designation (Classification)	Attainment	2201 / 4201 / 2410
Nitrogen Dioxide (NO2)		Attainment (Unclassified)	Attainment	2201 / 4201 / 2410
Sulfur Dioxide (SO2)		Attainment (Unclassified)	Attainment	2201 / 4201 / 2410
Carbon Monoxide (CO)		Attainment (Unclassified)	Attainment (Unclassified)	2201 / 4201/ 2410
Sulfuric Acid Mist (H2SO4)[1]		N/A	N/A	2201 / 4201
Particulate Matter (PM) [1]		N/A	N/A	2201 / 4201
Particulate Matter under 2.5 micrometers diameter (PM2.5)		Nonattainment	Nonattainment	2201 / 4201
Particulate matter under 10 micrometers diameter (PM10)		Attainment	Nonattainment	2201 / 4201 / 2410
Ozone	1-hour	N/A	Nonattainment (Severe)	2201 / 4201
	8-Hour	Nonattainment (Extreme)	Nonattainment	2201 / 4201
Greenhouse Gases (GHG)[1]		N/A	Unclassified	2410
Hydrogen Sulfide		N/A		2201 / 4201
Sulfates		N/A	Attainment	2201 / 4201
Visibility Reducing Particles		N/A	Unclassified	2201 / 4201
Vinyl Chloride		N/A	Attainment	2201 / 4201

[1] There is no national ambient air quality standard (NAAQS) for PM, H2SO4 or GHG. However, in addition to other pollutants for which no NAAQS have been set, PM, H2SO4 and GHG are listed as regulated pollutants with a defined applicability threshold under the PSD regulations (40 CFR 52.21).

6 District Rule 2410 - Air Quality Impacts

District Rules 2410 require an examination of the impacts of the proposed project on ambient air quality. The project must demonstrate, using air quality models, the facility's emissions of the applicable regulated air pollutants (NO2, SO2, CO, PM10) would not cause or contribute to a violation of:

(1) The applicable NAAQS,
(2) The applicable PSD increments (Appendix K-A),
(3) The applicable Soil & Vegetation concentration, and;
(4) Impact the visibility at Class I & II areas

These sections of this report include a discussion of the relevant background data and air quality modeling, and the District's conclusion that the Project will not cause or contribute to an exceedance of the applicable NAAQS or applicable PSD increments and is otherwise consistent with District Rule 2410 requirements.

6.1 Introduction

Under District regulation, a permit evaluation for a project that triggers PSD new Major Source, or PSD Major Modification (District Rule 2410) must include an air quality analysis demonstrating that the facility's emissions of the applicable regulated air pollutants will not cause or contribute to a violation of the applicable NAAQS or applicable PSD increments.

Please Note: A PSD increment for a pollutant applies only to areas that meet the corresponding NAAQS. Modeling analyses for each criteria pollutant emitted above the applicable significant emission rate (SER) are conducted and the results of this analysis are presented in this report.

6.2 National Ambient Air Quality Standard (NAAQS) Analysis

If a preliminary analysis shows that the ambient concentration impact resulting from the project's emissions is greater than the Significant Impact Level (SIL), then a full or cumulative impact analysis is required for that pollutant. The cumulative impact analysis can include nearby pollution sources in the modeling, and adds a monitored background concentration to account for sources not explicitly included in the model. The cumulative impact analysis must demonstrate that the project will not cause or contribute to a NAAQS or increment violation. If a preliminary analysis shows that the ambient concentration impact of the project by itself is less than the Significant Impact Level (SIL), then further analysis is generally not required.

Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 50 km from the facility). Modeling should be performed in accordance with District and EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W). AERMOD with its default settings is the standard model choice, with CALPUFF available for complex wind situations.

6.2.1 Additional Modeling Requirements

The follow are additional general modeling requirements that should be considered as per District Rule 2410 compliance.

- Include a Good Engineering Practice (GEP) stack height analysis, to ensure that
  a) Downwash is properly considered in the modeling, and
  b) Stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.
- Include initial "load screening," in which a variety of source operating loads and ambient temperatures are modeled, to determine the worst-case scenario for use in the rest of the modeling.
- Include an analysis of the impact on nearby Class I areas, generally those within 100 km of a project site, though the relevant Federal Land Manager (FLM) may specify additional or fewer areas. Figure 6-1 displays the 100km radius from the project site and Appendix K-B provides a complete list of Class I areas located within 100 km of the SJVAPCD boundaries. This analysis includes the:
  - NAAQS analysis
  - PSD increments analysis, and
  - Air Quality Related Values (AQRV) analysis
    - AQRVs are defined by the FLM, and typically limit visibility degradation and the deposition of sulfur and nitrogen. Generally, CALPUFF is the standard model choice for Class I analyses, since it can handle visibility chemistry as well as the typically large distances (over 50 km) to Class I areas.
- Include an impact analysis, showing the Project's effect on visibility, soils, vegetation, and growth.
  - The visibility analysis is independent of the Class I visibility AQRV analysis.

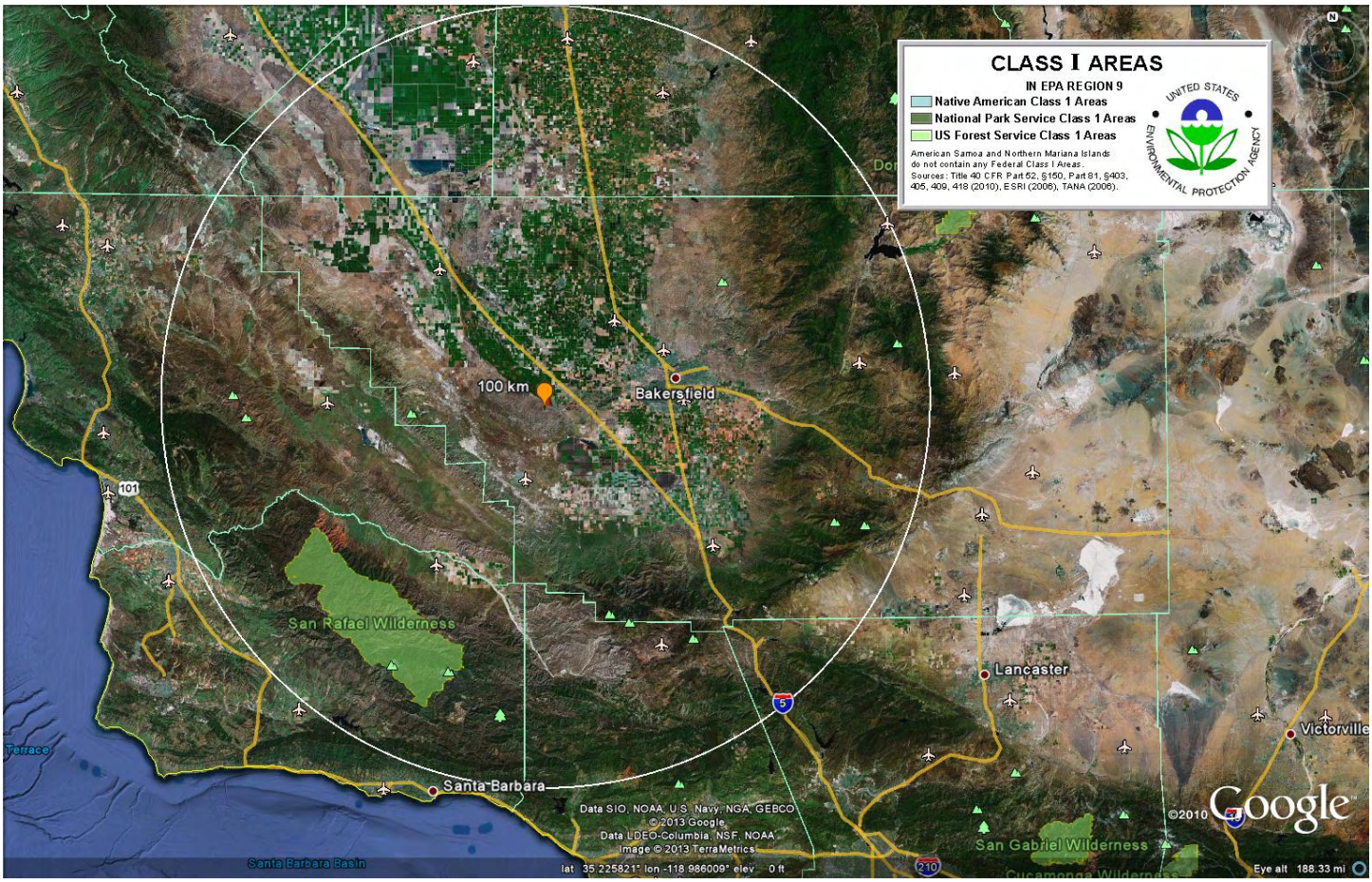


Figure 6-1 100km Radius of Project Site

6.3 Identification of Modeling Documentation

The modeling analysis is comprised of the documents listed in Table 6-1 below

Table 6-1 Modeling Documentation

Short Name	Citation
PSD Application	Determination of Compliance Application and Supplemental Information for the Prevention of Significant Deterioration (PSD) Permit Application" Document Dated May 2012
FLM1	Email sent from URS to FLM on 4/17/2012. Updated Q/d analysis.
FLM2	Email sent from FLM to URS confirming that no AQRV analyses
Class II	Email sent from URS to EPA IX & the District on 10/30/2012 w/ Class II analysis

The following briefly discusses each of the cited documents:

The PSD Application included the main document and supporting appendices discussing the proposed Project and the analyses performed in support of the compliance with District Rules 2201, 4201, and 2410. In addition to the supporting documents electronic model inputs and outputs were provided.

The FLM1 email sent by URS to the FLMs was an updated Q/d analysis for the updated emissions from the Project that shows that the Q/d is below the FLM screening level of 10. The FLM2 email from the FLM to URS provided confirmation that an AQRV analysis would not be required since the Q/d values were below the screening level of 10.

The Class II email and documentation sent by URS to EPA Region IX & the District described the methodology used and the results derived from Class II visibility analysis. The visibility analysis used a Level 1 analysis to perform the Class II visibility analysis.

6.4 Background Ambient Air Quality

District regulations require the air quality analysis to contain air quality monitoring data as needed to assess ambient air quality in the area for applicable regulated pollutants for which there are NAAQS that may be affected by the Project. In addition, for demonstrating compliance with the NAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, as determined by the District, so that the total concentration accounts for all contributions to current air quality.

Ambient air concentrations of ozone (O3), CO, NO2, SO2, PM10 and PM2.5 are recorded at monitoring stations throughout the San Joaquin Valley. In order to select the appropriate monitoring station the area surrounding the project site must be first evaluated. The area immediately surrounding the Project site can be characterized as being rural with farmland to northwest, north, east (near the project site and non-developed areas further out) and mountains to the west and south of the project site, see Figure 6-2. The only major industrial sources are located south of the project site consisting of oil & gas production (~ 4.0 km) and power generation operations (~ 8.0 km).

The monitoring station in Kern County that is closest to the Project Site is the Shafter–Walker Street Station located within 13 miles (21 kilometers) from the Project Site. This station measures ozone (O3) and NOX/NO2 concentrations, and is the most representative station to characterize background conditions for these pollutants near HECA.

The Bakersfield ─ 5558 California Avenue station is the next closest station and the closest that measures all pollutants except SO2 and CO. This station is located approximately 20 miles (32 kilometers) to the east of the Project site, and provides the best representation of the background levels for PM10 and PM2.5 for the area near HECA. In addition, it is the only station that measures these pollutants with adequate data capture within the San Joaquin Valley portion of Kern County.

The Bakersfield ─ Golden State Highway station is the only station in Kern County that measures CO. This station was closed early in 2010; thus the most recent measurements available for this station are for 2007–2009, as 2010 data did not have suitable data capture.

The only station in the SJVAB that monitors SO2 is the CARB station at First Street in Fresno, located approximately 102 miles (164 kilometers) to the north. Sulfur dioxide data have only

been recorded in Fresno County for 6 of the last 10 years (2003, 2007, 2008, 2009, 2010, 2011), a practice that is justified by the low levels that have been recorded for this pollutant where and when measurements have been made.

Table 6-2 below describes the maximum background concentrations, from the most recent available 3 year period of data collection, for which there are NAAQS that may be affected by the Project's emissions. Use of this method effectively assumes that the highest recently recorded pollutant concentrations for each averaging period are occurring during every such period over the 5-year meteorological input record. This static high background is then paired with modeled results.

Table 6-2 NAAQS & Background Concentration

Ambient Air Quality Standards			
Pollutant	**Averaging Time**	**National Standards Concentration**	**Background Concentration** ($\mu g/m^3$)
Respirable Particulate Matter (PM10)	24 Hour	150 $\mu g/m^3$	99
Fine Particulate Matter (PM2.5)	24 Hour[1]	35 $\mu g/m^3$	196
	Annual Arithmetic Mean	15 $\mu g/m^3$	22
Carbon Monoxide (CO)	1 Hour	35 ppm (40 mg/m^3)	4,581
	8 Hour	9 ppm (10 mg/m^3)	2,485
Nitrogen Dioxide (NO2)	1 Hour[2]	188 $\mu g/m^3$	140
	Annual Arithmetic Mean	100 $\mu g/m^3$	26
Sulfur Dioxide (SO2)[3]	1 Hour[5]	196 $\mu g/m^3$	42
	3 Hour[4]	1300 $\mu g/m^3$	26
	24 Hour	365 $\mu g/m^3$	13

1 - The PM2.5 24-hr value is the 98th percentile averaged over three years rather than the maximum
2 - The NO2 1-hr value is the 98th percentile averaged over three years rather than the maximum
3 - The SO2 annual standard is replaced by the more stringent SO2 1-hour standard
4 – No primary standard exist for SO2 3-hour standard. Value used is for the secondary standard
5 -- The SO2 1-hr value is the 99th percentile averaged over three years rather than the maximum

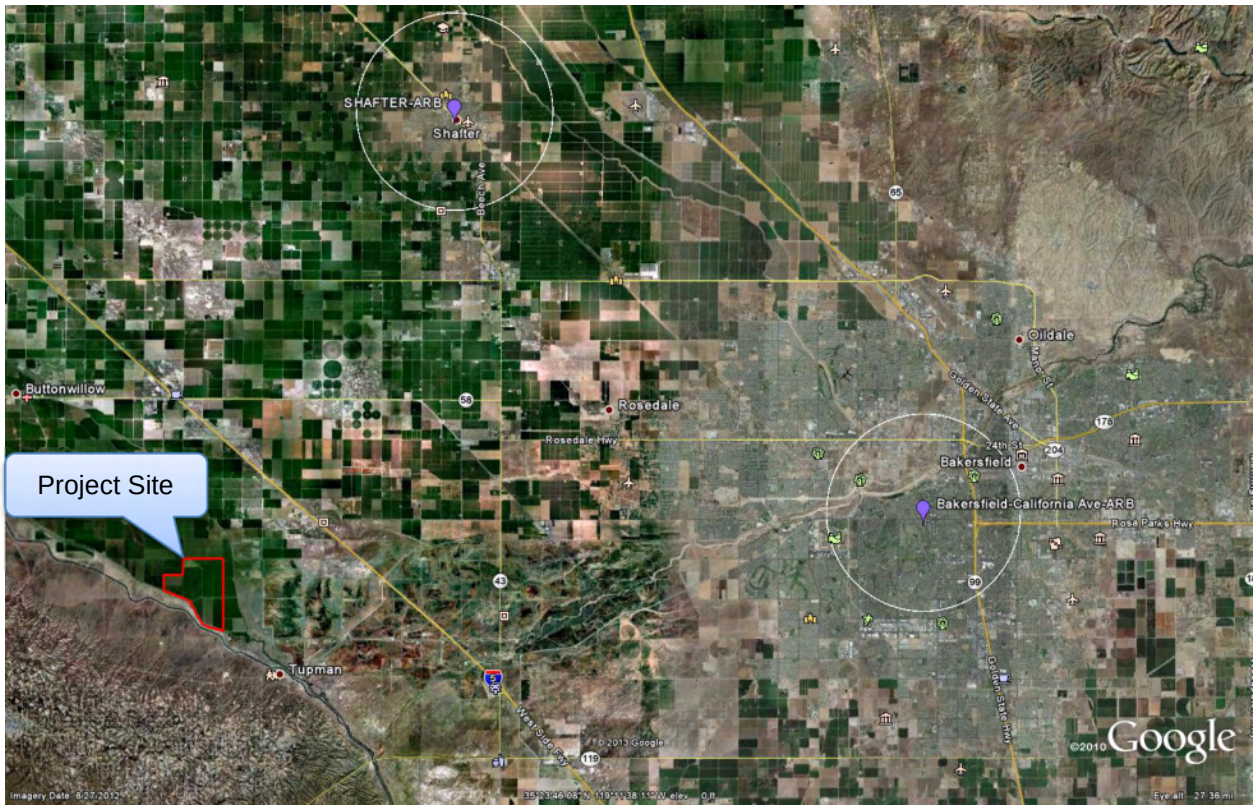


Figure 6-2 Nearby Monitoring Sites

6.5 Modeling Methodology for Class II areas

The applicant modeled and the District reviewed the impact of the project on the NAAQS and PSD Class II increments using AERMOD in accordance with District guidance and EPA's GAQM (Appendix W of 40 CFR Part 51). HECA is designated as a PSD source for three criteria pollutants: CO, NO2, and PM10. A project's impacts may be compared to the significant impact levels (SILs) as a screening modeling exercise that helps determine whether the project may cause or contribute to a violation of the NAAQS. The modeling analyses included the maximum air quality impacts during normal operations and startups and shut-downs, commissioning, as well as a variety of conditions to determine worst-case short-term air impacts.

6.5.1 Model Selection

As discussed in the PSD Application, the model selected for analyzing air quality impacts in Class II areas is EPA's preferred dispersion model AERMOD [Ver. 12060], along with AERMAP for terrain processing and AERMET for meteorological data processing. This is in accordance with the default recommendations in the District guidance and EPA's GAQM, Section 4.2.2 on Refined Analytical Techniques.

6.5.2 Meteorological Inputs

6.5.2.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. SJVAPCD provided the surface meteorological data collected for a five-year consecutive period (from 2006 – to 2010) at the Bakersfield Meadows Field Airport meteorological station maintained by the FAA.

The District processed these data using EPA's AERMET data processor and the District meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). The meteorological station is located on the northern end of the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site, with no intervening structures, hills, or water bodies that might significantly affect meteorological conditions. The project site, the meteorological site and the "area of interest" are located inland and close to each other.

For analyzing the representativeness of the meteorological dataset, the area of interest includes:

- the SIA where screening modeling predicts the Project's pollutant impact to be greater than the SILs, and
- Also includes the sources and receptors used in the modeling.

Other nearby surface meteorological sites were examined, but the Bakersfield Meadows Field Airport station had sufficient data completeness, is the closest, and is the most representative with no intervening high ground between the Project site and the meteorological tower. District believes that the chosen from 2006 – to 2010 Bakersfield Meadows Field Airport data is the most representative for the proposed project analysis. Further discussion of the meteorological data used in the analysis is given in the following section on land characteristics. **Please Note**: The other nearby sites (Fellows and Missouri Triangle) are considered prognostic datasets generated from MM5 data and at the current time are not acceptable by EPA.

Figure 6-3 Nearby Meteorological Dataset

6.5.2.2 Upper Air Data

For upper air data, the District selected (from 2006 – to 2010) the upper air site located in Oakland, California, located approximately 227 miles (366 km) northwest of the Project site as being the most representative site available that had data complete enough to use. No other upper air meteorological monitoring stations are located in the San Joaquin Valley Air Basin.

6.5.3 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

1) via elevation within AERMOD to assess plume interaction with the ground;
2) via a choice of rural versus urban algorithm within AERMOD; and
3) via specific values of AERMET parameters that affect turbulence and dispersion, namely surface roughness length, Bowen ratio, and albedo. The surface roughness length is related to the height of obstacles to the wind flow and is an important factor in determining the magnitude of mechanical turbulence. The Bowen ratio is an indicator of surface moisture. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption.

The applicant used terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data at a horizontal resolution of 30 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83, Zone 11). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

The applicant used surface roughness values in the modeling inputs developed by SJVAPCD. The District followed EPA's "AERMOD Implementation Guide" (2009 version) and the District's Guidance entitled "Procedure for Downloading & Processing NCDC Meteorological Data" in using EPA's AERSURFACE processor with the National Land Cover Data 1992 archive to determine surface characteristics for AERMET. The surface roughness characteristics are representative of the area surrounding the site where the meteorological data is collected. The District also used the criteria described in Section 3 (Representativeness) from EPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications (2000). AERSURFACE uses a Land Use data base from 1992. In addition, SJVAPCD reviewed recent aerial photos for the area, which show that the Bakersfield Meadows Field Airport meteorological tower is surrounded by a light industrial, residential, and rural area.

Figure 6-4 Bakersfield Meadows Field Airport

The applicant did a qualitative comparison of the following factors:

- Proximity
- Height of measurement
- Surface characteristics

The Bakersfield Airport is the closest full-time meteorological recording station to the Project Site. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas.

Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are at approximately the same elevation. Additionally, there are no significant terrain features separating the Bakersfield Airport from the Project Site that would cause significant differences in wind or temperature conditions between these respective areas.

6.5.4 Receptors Grid

Receptors in the model are geographic locations at which the model estimates concentrations. The applicant placed receptors such that they have good area coverage and are closely spaced enough so that the maximum model concentrations can be found. At larger distances, spacing between receptors may be greater than it is close to the source, since concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project boundary.

The applicant used a Cartesian coordinate receptor grid to provide adequate spatial coverage surrounding the project area, to identify the extent of significant impacts, and to identify the maximum impact location. In the analyses, the applicant placed receptors using the following telescoping grid out to 10 km, as seen in Figure 4-1 & 4-2 of the Project application.

- 25-meter spacing along the property line and extending from the property line out 100 meters;
- 50-meter spacing from 100 to 250 meters beyond the property line;
- 100-meter spacing from 250 to 500 meters beyond the property line;
- 250-meter spacing from 500 meters to 1 kilometer beyond the property line;
- 500-meter spacing from 1 to 2 kilometers beyond the property line; and
- 1,000-meter spacing from 2 to 10 kilometers beyond the property line.

During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time was located within the portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid was placed around the original maximum concentration point, and the model was rerun. The dense grid used 25-meter spacing and extended to the next grid point in all directions from the original point of maximum concentration. The only dense refined receptor grid that was needed in the current modeling analysis occurred for 24-hour SO2 operational modeling, where a dense grid was placed in the hills southwest of the Project site. Details may be seen in the model input files included in the electronic files submitted with this PSD Application.

6.5.5 Load Screening and Stack Parameter

The applicant performed initial “load screening” modeling, in which nine source operating loads and ambient temperatures were modeled, to determine the “worst case” stack parameter scenario for use in the rest of the modeling, whenever normal operations are considered. At a

minimum two loads should be considered: a minimum load of 50% and a maximum load of 100%. The choice of "worst case" can be different for each pollutant and averaging time, because different sources' emissions respond differently to temperature and flow rate.

For all pollutants and averaging times, screening modeling was performed with maximum emissions and the most conservative stack parameters for each source, regardless of whether all equipment will run at the same time in this worst-case stack parameter and emissions configuration. This methodology was performed to determine conservative worst-case off-site impacts without the need of sensitivity modeling for each piece of equipment or time period. Normally, all sources will not run at the same time with their worst-case stack parameters and emissions. For example, the emergency ancillary equipment (generators, firewater pump) will not all be tested at the same time during a start-up sequence. However, if the most conservative impact scenario complied for the CAAQS and NAAQS, the equipment was kept in the modeling with maximum emissions and the most conservative stack parameters to eliminate the need for sensitivity modeling iterations. Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application.

More refined modeling was completed for several pollutants to more accurately depict the activities occurring concurrently for short averaging times. Sensitivity modeling was completed for CO 1-hour, and it was determined that the CTG/HRSG shut-down scenario (20 percent load burning natural gas) gave higher impacts than the CTG/HRSG starting up scenario. However, the maximum CO 8-hour impact was determined to occur during CTG/HRSG start-up mode when other sources are operating for that duration of time. It was determined that the Feedstock dryer gave higher short-term SO2 impacts in operations mode than in start-up or shut-down mode, while all other maximum pollutant impacts for the Feedstock dryer occurred during Feedstock dryer start-up mode. Finally, maximum NO2 1-hour NAAQS impacts occur when the CTG/HRSG and Feedstock dryer are operating in on-peak power mode rather than off-peak power mode.

Table 6-3 Source Stack Parameters

Source	Operating Condition Associated with Emission Rate	Stack Ht. (ft)	Temperature (°F)	Exit Velocity (ft/sec)	Stack Diameter (ft)
HRSG Stack	Normal On-Peak Emissions (Case 1)	213	200	53.81	23
Feedstock Dryer	Normal On-Peak Emissions (Case 1)	305	200	19.16	16
Tail Gas Thermal Oxidizer Stack	Normal operations	165	1200	50.93	2.5
Auxiliary Boiler	Normal operations	80	300	30.18	4.5
Rectisol® Flare	Annualized emissions, start-up flaring (effective stack height and diameter)	217.83	1831.73	65.62	0.87
Gasification Flare	Annualized emissions, start-up and shut-down	219.63	1831.73	65.62	1.22

	flaring (effective stack height and diameter)				
SRU Flare	Normal Operations, Pilot (effective stack height and diameter)	215	1831.73	65.62	0.32
Nitric Acid Plant Stack	Normal operations	145	239	17.11	8
Emergency Diesel Generator 1	Annualized emissions	20	760	221.05	1.2
Emergency Diesel Generator 2	Annualized emissions	20	760	221.05	1.2
Emergency Diesel Firewater Pump	Annualized emissions	20	850	155.91	0.7
Ammonia Synthesis Plant Start-up Heater	Annualized emissions	80	300	18.71	3.5

6.5.6 Good Engineering Practice (GEP) Analysis

The applicant performed a Good Engineering Practice (GEP) stack height analysis, to ensure that:

a) downwash is properly considered in the modeling, and
b) stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.

As is typical, the GEP analysis was performed with EPA's BPIP Prime (Building Profile Input Program) software, which uses building dimensions and stack heights as inputs. All stacks in the HECA Project will be less than or equal to the GEP default height of 65 meters, except for the Feedstock dryer, three flares (SRU, Gasification, Rectisol), and the CO2 vent. Based on the analysis, the applicant showed that the GEP stack heights for the Feedstock Dryer and CO2 Vent were greater than 65 m (213 ft), which is greater than the planned actual height of 92.9 m (304.8 ft) and 79.2 m (259.8 ft).

The flares are not within 5 times L (138.5 meters) of the gasification structure or any other structure that is large enough to create downwash for the flares in BPIP. It is important to note that the flares will be built at 76.2 meters tall for safety from a project engineering perspective. However, a 65-meter stack height, or GEP, was used to calculate specific effective stack heights for each flare modeling scenario based on the flare's heat release rate during that modeling scenario. The effective stack height is the height of the stack plus the height above the stack where the flare flame ends and a plume can begin. The effective stack parameters were calculated using the SCREEN3 technique, and were input into the AERMOD model. Therefore, the lower 65 meter stack height was used as the stack height in the calculation of the effective stack heights for the flares, rather than the actual stack height.

The applicant also showed that the GEP stack height for the other equipment was similarly greater than the planned heights. So, for all emitting units, the applicant used the planned actual stack heights for inputs in AERMOD modeling, and included wind direction-specific Equivalent Building Dimensions to properly account for downwash.

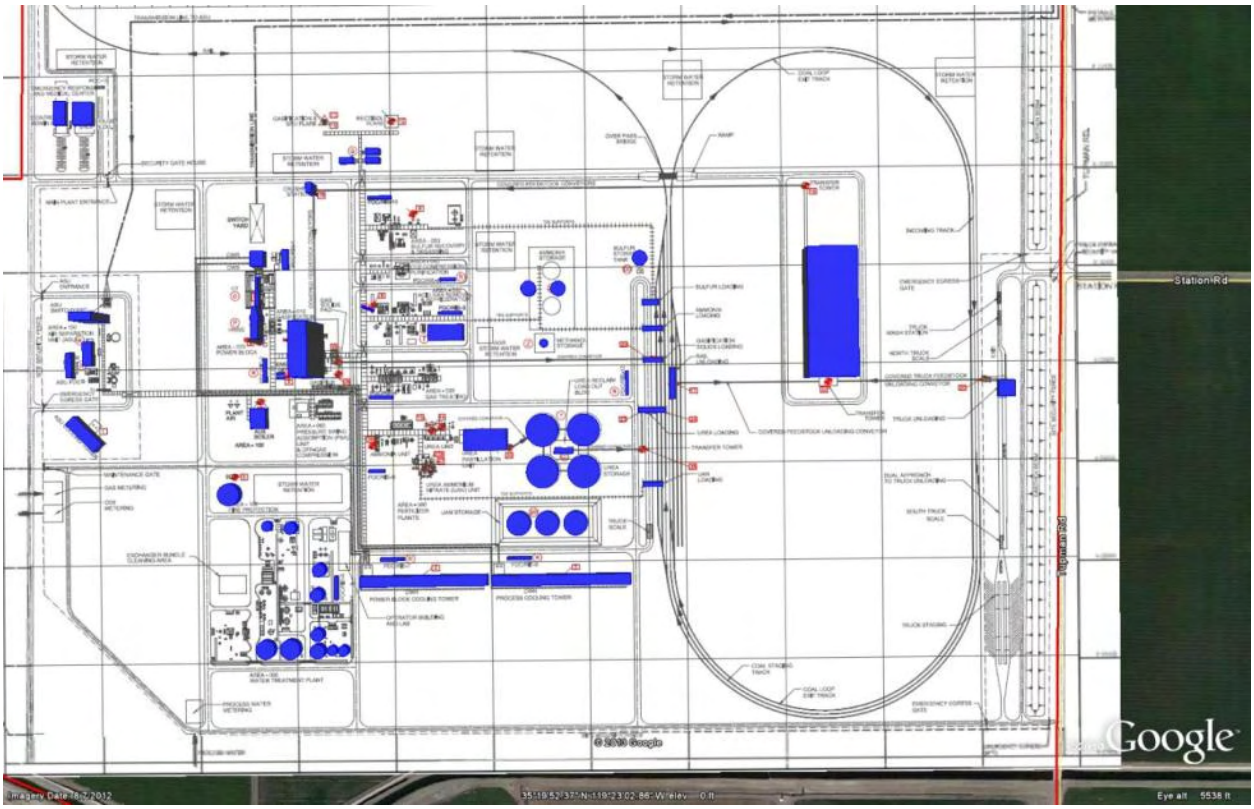


Figure 6-5 Onsite Structures (Blue Objects)

6.6 NAAQS and Class II Increment Consumption Analysis

6.6.1 Pollutants with Significant Emission Rates

District Rule 2410 requires an air quality impact analysis be performed for each regulated pollutant (for which there is a NAAQS) that a major source has the potential to emit in a significant amount, i.e. an amount greater than the Significant Emission Rate for the pollutant.

Applicable project emissions and the Significant Emission Rates are shown in Table 6-4 (provided by the processing engineer). As shown in Table 6-4 below, the District does not expect the project to result in significant amount of emissions of SOx or Lead. However, based on the information provided by the processing engineer it is expected that the project will result in significant amount of emissions of CO, NOx, PM2.5 and PM10. Therefore, this project triggers the PSD air impact analyses for CO, NOx, and PM10 only.

Table 6-4 Criteria Pollutant Emitted Compared to PSD Significance Thresholds

Criteria Pollutant	Project Emissions	Significant Emission Rate	PSD applicable?
	tons/year	*tons/year*	
CO	272	100	Yes
NOX	159	40	Yes
PM10	90	15	Yes

Criteria Pollutant	Project Emissions	Significant Emission Rate	PSD applicable?
	tons/year	*tons/year*	
PM2.5	80	10	Non-Attainment
SO2	32	40	No
Pb	0.0	0.6	No

6.6.2 Preliminary Analysis: Project-only impacts (Normal Operations & Startup)

EPA has established Significant Impact Levels (SIL) to characterize air quality impacts, see the Table 6-5 below or Appendix K-A. SIL is the ambient concentration for a given pollutant and averaging period which the resulting concentration from the facility's emissions must stay below in order for the source to be considered to have an insignificant impact. For modeled concentrations below the SIL, further air quality analysis for the pollutant is generally not required. For maximum concentrations that exceed the SIL, District Rule 2410 requires a cumulative modeling analysis which incorporates the combined impact of nearby sources of air pollution to determine compliance with the NAAQS and PSD increments.

Table 6-5 below, shows the results of the preliminary or Project-only analysis based on normal operations for the project. The project impacts are significant only for 1-hour NO2 and 1-hour CO, and the District has determined that cumulative impact analysis or cumulative screening analysis are required for only these two pollutants. The maximum SIA extended out to 13 kilometers from the facility.

Table 6-5 Project Significant Impact – Class II

NAAQS Pollutant & Averaging Time	Project-only Modeled Impact	Significant Impact Level (SIL)	Project Impact Greater than SIL?	Significant Monitoring Concentration (SMC) (µg/m3)
	ug/m3	*µg/m3*		
CO, 1-hour	2,625	2000	Yes	---
CO, 8-hour	368	500	No	575
NO2, 1-hour	22	7.5	Yes	---
NO2, annual	0.6	1	No	14
PM10, 24-hour	3.9	5	No	10
PM10, annual	0.6	1	No	---

PM10 24-hour, PM10 annual, CO 8-hour, and NO2 annual modeled impacts from the Project operations are less than the applicable SIL. The modeled CO 1-hour impact is greater than the SIL of 2,000 µg/m3. A refined scenario (cumulative screening analysis) was conducted which included permitted and non-permitted sources (on site mobile) and concentrations from a conservative background site. This refined analysis indicated that the CO 1-hour concentration would be 7,244 µg/m3 (maximum modeled 2,663 µg/m3 + 4,581 µg/m3

background) which would be significantly less than the NAAQS of 40,000 µg/m3. Therefore no additional cumulative impact analysis was warranted.

The NO2 1-hour concentration was greater than the SIL of 7.5 µg/m3 and required a cumulative impact analysis.

Significant Monitoring Concentrations (SMC) are applicable to PSD pollutants only, and are compared to the same modeled pollutant concentrations from the Project as were compared to the SIL. As noted in Table 6-5 above, the SMCs are higher than SILs. And HECA's estimated impacts are lower than all applicable SMCs, therefore, monitoring is not required. Currently, no SMC exists for NO2 1-hour.

6.6.3 Cumulative Impact Analysis / Increment

A cumulative NAAQS or PSD increment impact analysis considers impacts from nearby sources in addition to impacts from the Project itself. In addition, for demonstrating compliance with the NAAQS, the applicant added a background concentration to represent those sources not explicitly included in the modeling. As a result, the total accounts for all contributions to current air quality. In this case, the cumulative impact analyses submitted demonstrated compliance with the NO2 1-hour NAAQS.

For demonstrating compliance with the PSD increment, only increment-consuming sources need to be included, because the increment concerns only changes occurring since the applicable baseline date. In this analysis, there is no CO 1-hour and 8-hour, and NO2 1-hour PSD increment; therefore, no PSD increment analysis is required.

The Project's maximum modeled impacts for PM10 24-hour and annual, and NO2 annual are below the applicable SILs. Therefore, an increment consumption analysis is not required and is assumed to be insignificant and no preconstruction monitoring or additional impact analyses are required.

6.6.3.1 Nearby Source Emission Inventory

For both the PSD increment and NAAQS analyses, there may be a large number of sources that could potentially be included, so judgment must be applied to exclude small and/or distant sources that have only a negligible contribution to total concentrations. Only sources with a significant concentration gradient in the vicinity of the source need be included; the number of such sources is expected to be small except in unusual situations. (GAQM 8.2.3)

SJVAPCD provided a list of all stationary sources within the District and within ~75 km of the project. A comprehensive procedure was used to determine which sources were included in the emissions inventory.

It should be noted that short-term maximum emission rates rather than annual emission rates determine the distance over which a facility might have a significant impact for short-term standards (e.g., hourly NO2).

The applicant identified numerous units (371 permitted units) nearby for inclusion in the emissions inventory for the cumulative analysis, based on discussions with SJVAPCD. The

non-HECA facilities and their hourly NO2 emissions are included in the cumulative compliance demonstration; see Appendix K-C for a complete listing of facilities and units.

These facilities are large enough and close enough to the Project site to have the potential to directly impact the Project's significant impact area.

Current EPA NO2 guidance suggests that emphasis on determining which nearby sources to include in the nearby source inventory could be limit on the area within about 10 kilometers of the project location in most cases, which indicates that the HECA inventory is adequate for performing these cumulative analyses (p.16 of "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard", Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors, March 1, 2011).

Nevertheless, as an additional factor, the applicant also considered emission levels and distance as factors for determining which sources with small emissions and/or at large distances would be reasonable to exclude from the analysis. The applicant proposed that NO2 sources with a ratio less than 2.0 (based on the ratio of tons/year based on daily emission rates to the distance to the project site) be eligible for exclusion from the relevant inventories. This ratio was used to classify those that clearly should be included and those that could be clearly excluded.

Therefore, taking into consideration the current EPA guidance suggesting a focus on sources within 10 km, the District concludes that the combination of a representative background monitored concentration, and the additional consideration of emission levels and distance, provide sufficient justifications for the inventory used in the cumulative analysis.

6.6.3.2 PM2.5-Specific Issues

The District is current in non-attainment for the PM2.5 NAAQS and therefore no analysis is required under District Rule 2410.

6.6.3.3 NO2-Specific Issues

While the new 1-hour NO2 NAAQS is defined relative to ambient concentrations of NO2, the majority of NOx emissions from stationary sources are in the form of nitric oxide (NO) rather than NO2. Appendix W notes that the impact of an individual source on ambient NO2 depends in part "on the chemical environment into which the source's plume is to be emitted" (see Appendix W, Section 5.1.j). Because of the role NOx chemistry plays in determining ambient impact levels of NO2 based on modeled NOx emissions, Section 5.2.4 of Appendix W recommends a three-tiered screening approach for NO2 modeling. Later guidance documents issued by EPA expand on this approach. Tier 1 assumes full conversion of NO to NO2. Tiers 2 and 3 are refinements of the amount of conversion of NO to NO2. The applicant used the Tier 3 Plume Volume Molar Ratio Method (PVMRM) option in AERMOD, which simulates the interaction of NO with ambient O3 to form NO2. The PVMRM determines the conversion rate for NOx to NO2 based on a calculation of the NOx emitted into the plume, and the number of O3 moles contained within the volume of the plume between the source and receptor. In addition to requiring monitored ozone, the method requires specification of an in-stack NO2/NOX ratio. The following presents a discussion of

the in-stack NO2/NOx ratios used in PVMRM for the proposed emissions units and nearby sources for the cumulative impact analysis.

A. In-Stack NO2/NOx Ratio

Defining source-specific in-stack NO2/NOx ratios is part of the refinement of the Tier 3 PVMRM. An in-stack NO2/NOx ratio of 0.50 is the default value and can be used without further justification. This applies not only for the proposed permitted source but also for the other sources used in the cumulative impacts analysis. As discussed in Section 6.6.3.1, numerous facilities (with 371 emission units among them), see Appendix K-C, were included in the cumulative impacts analysis. For the proposed permit units and units in the cumulative impacts analysis, the applicant did not use the default value of 0.50, except for the Covanta Delano Inc Fluidized bed combustors (2 units), Mt. Poso Cogen Fluidized bed combustor, Rio Bravo Jasmin Solid Fuel combustor, Rio Bravo Poso Solid Fuel combustor.

Table 6-6 In-Stack NO2/NOx Ratios for Nearby Sources

Source Type	Fuel	In-stack Ratio Used
Boilers/Steam generators	Biomass, NG, Vapor	0.1
Turbines (including cogeneration, simple-/ combined-cycle, and gas compressor applications)	NG	0.1032 (small turbines) 0.17 (large turbines)
Emergency turbine	Diesel	0.1
Other cogeneration sources	Solid Fuel, Multi-Fuel	0.01
Process Heaters/Dryers	NG, Vapor	0.32 / 0.1 (heaters or both) / (dryers)
IC engines (including those acting as gas turbine starters or powering pumps)	Diesel	0.2
	NG	0.1
IC engines (acting as compressors)	Diesel	0.2
	NG	0.6
Ovens	NG	0.32

For the emergency generators, firewater pump, ammonia startup heater, and auxiliary boiler, the NO2/NOX in-stack ratios were obtained from the SJVAPCD 2010 draft guidance document, Assessment of Non-Regulatory Options in AERMOD Specifically OLM and PVMRM and the CAPCOA Modeling Compliance of the Federal 1-hour NO2 NAAQS. For the emergency generators and fire water pump, an in-stack ratio of 0.2 was used from the “IC Engines (Diesel)” category. The ammonia start-up heater used an in-stack ratio of 0.32 from the “Heaters (NG)” category. For the auxiliary boiler, an in-stack ratio of 0.1 was used from the “Boilers (NG)” category.

Limited information is available regarding in-stack NO2/NOX ratios for thermal oxidizers and flares. The exhaust from the thermal oxidizer or flares will have very little to no residence time in the stack, so almost no conversion of nitrogen oxide (NO) to NO2 is expected. For these sources, it was conservatively assumed that 10 percent of the NOX will be NO2.

No data exist for the NO2/NOX in-stack ratio for turbines burning hydrogen-rich fuel or the associated Feedstock dryer. The turbine vendor expects the NO2/NOX in-stack ratio will be similar to turbines that burn natural gas. Based on the in-stack NO2/NOX ratio of 0.091 for a natural gas turbine as determined by SJVAPCD guidance, and accounting for the conversion of NO to NO2 across the oxidation catalyst that could be as high as 20 percent (NO2/NOX ratio 0.2), HECA proposes to use the conservative NO2/NOX in-stack ratio of 0.3 for all turbine and Feedstock dryer operating conditions. Neither the turbine nor oxidation catalyst vendor could provide written documentation regarding the NO2/NOX in-stack ratio, although this ratio was their professional engineering estimate. Emissions from the nitric acid plant will be cleaned before being discharged to the atmosphere by catalytic decomposition and reduction of both nitrous oxide (N2O) and NOX. The N2O emissions are treated in a tertiary reduction system, in a reducing catalyst that uses high temperature rather than a reducing agent, to convert 95 percent of the remaining N2O emission to molecular nitrogen (N2) and nitric oxide (NO). The NOX emissions (including the NO formed in the N2O converter) are then reduced in one or more selective catalytic reduction (SCR) unit(s), with injected ammonia as a reducing agent, as is typical for NOX control in flue gas systems. The nitric acid unit vendor and Project design engineers estimate that approximately 50 percent of the NO converts to NO2 in the exhaust, therefore an in-stack ratio of 0.5 was used. Table 6-7 presents the resulting PVMRM in-stack NO2/NOx ratios.

Table 6-7 In-Stack NO2/NOx Ratios for Project Units

Source / Emission Units	NO2 / NOx Ratio
HRSG Stack	0.3
Feedstock Dryer	0.3
Tail Gas Thermal Oxidizer Stack	0.1
Auxiliary Boiler	0.1
Rectisol® Flare	0.1
Gasification Flare	0.1
SRU Flare	0.1
Nitric Acid Plant Stack	0.5
Emergency Diesel Generator 1	0.2
Emergency Diesel Generator 2	0.2
Emergency Diesel Firewater Pump	0.2

Source / Emission Units	NO2 / NOx Ratio
Ammonia Synthesis Plant Start-up Heater	0.32

1. Proposed Units
   The in-stack ratios used for the proposed units were based on the best available data known at the time the project was proposed and modeled. Currently there is still limited or no data available for some of the processes/fuel types that are proposed at the facility.

2. Nearby Sources for Cumulative Impacts Analysis
   The applicant performed a full impacts analysis, which included the 371 emission units at several nearby facilities. In-stack ratios for these emission units were based on data gathered by the District on historical source test conducted nation-wide.

B. NO2 monitor representativeness/conservativeness
   As mentioned above, the applicant chose the Shafter–Walker Street Station monitor for background NO2 concentrations. This monitor is 13 miles from the HECA site.

C. O3 background Monitor Representativeness
   The applicant has indicated that since O3 is a regionally-formed pollutant, the nearness of the monitoring site to the Project is the most important criterion for representativeness. The Shafter–Walker Street Station monitor is 13 miles away from the HECA site, and the District agrees that it is adequately representative.

D. Missing O3 data procedure
   Ozone data used in this analysis was prepared by the District using a monthly hour of the day fill method. This provides a reasonable and conservative procedure for filling in missing ozone values.

E. Combining Modeled and Monitored Values
   The applicant proposed to combine each modeled concentration with the background concentration from the corresponding hour ("hour-by-hour" approach) pairing. The applicant correctly used the first highest values from the distribution for each temporal combination. (The EPA March 2011 memo's "first-tier" approach uses the 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data as a uniform background contribution but also mentions the above procedure as a suggested temporal pairing option on p.20.) This procedure is based on a conservative assumption.

   The District believes that the applicant's overall approach to the 1-hour NO2 analysis for the HECA, including the emission inventory, background concentrations of NO2 and O3, and method for combining model results with monitored values, is adequately conservative.

6.6.3.4 Startup and Shutdown Analyses

The emission scenario used in the NO2 1-hour SIL and NAAQS cumulative modeling was developed following guidance from the March 2011 USEPA Memo. For this modeling, the CTG/HRSG and Feedstock dryer operate in normal on-peak power mode. Start-up emissions for the CTG/HRSG are limited to 9 hours per year, while shut-down emissions are limited to 18 hours per year. Start-up emissions for the Feedstock dryer are limited to 8 hours per year, with shut-down emissions at 8 hours per year. Annualized maximum 1-hour NO2 start-up/shut-down emission rates for these two sources are lower than their normal maximum NO2 1-hour rates; therefore, the maximum normal NO2 1-hour emission rates for the CTG/HRSG and Feedstock dryer were used.

Similarly, the SRU flare and tail gas thermal oxidizer have maximum impacts during normal operations with pilot and process vent disposal, respectively, rather than during an annualized start-up period. The Rectisol® and gasification flares were included with maximum annualized start-up flaring emission rates, which are higher than their normal emission rate during pilot mode.

The auxiliary boiler and nitric acid unit operations were included at their peak hourly emission rate. The ammonia plant start-up heater also was included with an annualized start-up 1-hour NO2 emission rate. Finally, all three ancillary diesel engines, including the two emergency diesel generators and firewater pump, were included in the modeling with annualized emission rates. Mobile sources were not included in this modeling scenario.

The model results are shown in Table 6-8 for the cumulative impacts analysis. The results demonstrate that emissions from HECA will also comply with the 1-hour NO2 NAAQS during startup and shutdown conditions.

6.6.3.5 Results of the Cumulative Impacts Analysis

The results of the PSD cumulative impacts analysis for HECA's operations for the 1-hr NO2 are shown in Table 6-8. The analysis demonstrates that emissions from HECA will not cause or contribute to exceedance of the NAAQS for 1-hour NO2 or for any applicable PSD increments. As discussed above, HECA's maximum modeled concentrations are below the SILs for annual NO2, 24-hour PM10, and annual PM10; therefore, a cumulative impacts analysis was not required to demonstrate compliance for these pollutants/averaging times.

The District also considered additional information to ensure that the Project would not be responsible for causing a new NAAQS exceedance outside this modeling area. The District considered sources within the County of Kern (no sources of interest were located outside of the county) that were not included, but which had been evaluated for inclusion/exclusion, in the cumulative impacts modeling above. The District concluded that these sources are either small enough or distant enough that the Project's expected emissions along with emissions from these sources would not create any new NAAQS exceedance in the modeling area outside of the SIA, of 13 kilometers.

Table 6-8 Compliance with Class II PSD Increments and NAAQS

NAAQS Pollutant & Averaging Time	All Sources Modeled Impact	PSD Increment Consumption	Background Concentration	Cumulative impact w/ background	NAAQS *(ug/m3)*	PSD Increment
NO2, 1-hr	(Paired)	NA	(Hourly)	119	188 (100 ppb)	NA

1 - There are no PSD increments defined for 1-hour NO2.

6.7 Class I & II Area Analysis

6.7.1 Class I Area Significant Impact Level (SIL) Analysis

Per USEPA Region IX request, a Class I Area SIL modeling analysis was completed to demonstrate compliance with the Class I SILs. Class I Areas are certain national parks, wilderness areas, and national monuments that are protected by the most stringent PSD requirements. The nearest Class I Area to the Project site is the San Rafael Wilderness Area, which is approximately 60 kilometers southwest of the HECA site.

Modeling was conducted for the NO2 annual, PM2.5 24-hour and annual, and PM10 24-hour and annual Class I SILs. The Class I SILs are presented in the table below. Modeling for the Class I PM2.5 SILs was completed, because the San Rafael Wilderness Area is in Santa Barbara County, which is an unclassified/attainment area for PM2.5. Class I SILs for NO2 1-hour, and CO 1-hour, and 8-hour do not exist. Impacts due to HECA operations without mobile sources were modeled, using the same modeling scenarios as described previously. The AERMOD model was applied for the Class I SIL modeling analyses, which used a receptor grid extending out 50 kilometers from the Project site, the same receptor grid used in the NO2 1-hour NAAQS cumulative analysis. The AERMOD model has been evaluated for estimating impacts out to 50 kilometers, and it is believed that this is the maximum extent of the model's reliability; therefore, receptors did not extend beyond 50 kilometer into the San Rafael Wilderness Area. However, this modeling approach, with receptors out to 50 kilometers, gave an understanding of whether the model predicted Class I SILs would be contained inside the 50-kilometer grid.

Table 6-9 Class I Significant Impact Levels

Pollutant	Averaging Period	Class I Significant Impact Level (SIL) *(µg/m3)*
NO2	Annual	0.1
PM10	24 hour	0.32
	Annual	0.2
PM2.5	24 hour	0.07
	Annual	0.06

The Figure 6-1 through 6-5 of the PSD application indicates that the maximum concentrations for NO2, PM10, and PM2.5 would fall within 2 to 3 km from the facility boundary and the model predicted that the concentrations would fall below the Class I SIL out 20 to 30 kilometers

southwest of HECA, in the direction toward San Rafael Wilderness Area, as shown on Figures 6-4 and 6-5. Therefore, modeled concentrations due to HECA operations in the vicinity of San Rafael Wilderness would be expected to be well below the Class I significance levels and compliance with the Class I SILs would be achieved. Therefore, since the SILs are not expected to be exceeded in the Class I Area, a Class I Area increment analysis is not required.

6.7.2 Air Quality Related Values (AQRV)

6.7.2.1 Class I Areas

Class I Areas are certain national parks, wilderness areas, and national monuments that are protected by the most stringent PSD requirements. There are three Class I areas near the project site and are listed below, with only one being located within 100 km of the Project site:

- San Rafael Wilderness (60 km)
- Domelands Wilderness Area (105 km)
- Sequoia National Park (120 km)

Based on the most recent Federal Land Managers' Air Quality Related Values (AQRV) Work Group (FLAG) published guidance[2] the following screening approach is used to determine whether a more refined Class I Air Quality Analysis is required. This approach, which only applies to projects located more than 50 km from a Class I area, requires adding all of the visibility-related emissions (SO2, NOx, PM10 and sulfuric acid mist) from a project (based on 24-hour maximum allowable emissions expressed in units of tons per year) and dividing the sum by the distance between the project and the Class I area. If the result is less than 10, the project is presumed to have negligible impacts to Class I AQRVs. On April 18, 2012, the U.S. Forest Service confirmed that Class I AQRV analyses would not be required for the HECA Project. The table below shows that the Project's emissions, based on emissions from the project engineer, are well below the FLAG screening criteria. This would confirm that the Q/d submitted to the FLM is still below 10 and therefore, no further Class I AQRV analysis is required.

Table 6-10 Class I Air Quality Screening Analysis

Pollutant	Annual Emission *(lbs)*	Annual Emission *(Tons)*
SO2	64,574	32.29
PM10	180,183	90.09
NOx	317,771	158.89
Sulfuric Acid Mist	0	0.00
Total Tons per Year		**281.26**
Class I Areas		
San Rafael Wilderness	Distance (km) From Project	60.00
	Q/d	4.69
	Class I Analysis Required	NO

[2] "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 450/2-81-078, December 1980

Domelands Wilderness Area	Distance (km) From Project	105
	Q/d	2.68
	Class I Analysis Required	NO
Sequoia National Park	Distance (km) From Project	120.00
	Q/d	2.34
	Class I Analysis Required	NO

6.7.2.2 Class II Areas

National Park Service (NPS) PSD guidance states that projects should not degrade air quality and/or visibility in Class II areas. Class II areas are defined as the following areas when greater than 10,000 acres, and in existence since 1977:

- National monuments;
- National primitive areas;
- National preserves;
- National recreation areas;
- National wild and scenic rivers;
- National wildlife refuges;
- National lakeshores and seashores; and
- National parks and wilderness areas.

The nearest parks that fit the Class II area definition are:

- Sequoia National Forest, 54 kilometers away, and
- Los Padres National Forest, 49 kilometers away from HECA.

Since both of these parks are approximately 50 kilometers or farther from HECA, and the Q/d is less than 6, per the FLAG guidance screening technique, impacts would be less than significant. Therefore, no Class II Area visibility analysis would be required.

Table 6-11 Class II Air Quality Screening Analysis

Pollutant	**Annual Emissions *(lbs)***	**Annual Emissions *(Tons)***
SO2	64,574	32.29
PM10	180,183	90.09
NOx	317,771	158.89
Sulfuric Acid Mist	0	0.00
Total Tons per Year		**281.26**
Class II Areas		
Sequoia National Forest	Distance (km) From Project	54.00
	Q/d	5.21
	Class II Analysis Required	NO
Los Padres National Forest	Distance (km) From Project	49.00
	Q/d	5.74
	Class II Analysis Required	NO

6.7.3 Class I Increment Consumption Analysis

The District requires an analysis addressing Class I increment impacts for the applicable pollutants regardless of the results of the Class I AQRV analysis. As noted in Section 6.7.2.1 the screening analysis indicated the impacts from the proposed units would be below the Class I SILs for NO2, PM10, and PM2.5 and therefore a Class I increment analysis is not required.

7 Other Impact Analysis

In addition to assessing the ambient air quality impacts expected from a proposed new source, District Rule 2410 requires that the District evaluate other potential impacts on:

1) Soils and vegetation,
2) Growth; and
3) Visibility impairment.

The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area.

7.1 Soils and Vegetation

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with the HECA's emissions. This component generally includes:

- a screening analysis to determine if maximum modeled ground-level concentrations of project pollutants could have an impact on plants; and
- a discussion of soils and vegetation that may be affected by proposed project emissions and the potential impacts on such soils and vegetation associated with such emissions.

The applicant presented its discussion of the potential impacts on soils and vegetation in Section 6.3 of its PSD application. Section 6.3 included a discussion of the existing setting, nitrogen deposition potential, modeled impacts, and biological resources (including observed vegetation communities/land cover types and plants).

The Section 6.3 presents the use of EPA's "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (1980) to determine if maximum modeled ground-level concentrations of NO2, SO2, PM10, H2S and CO from the Project could have an impact on plants, soils, and animals. In addition, the applicant submitted information that included a discussion of the Project location and adjacent areas, the observed vegetation communities/land cover types, the observed plants, and soil types as part of the description of the various vegetation communities/land cover types and plant habitat observed within the project study area. The modeled impacts of NO2, SO2, PM10, H2S and CO emissions from the facility, individually, and in addition to the background concentrations of NO2, SO2, PM10, H2S and CO, are well below the minimum impact levels/screening concentrations identified in the Screening Procedure for sensitive plants. The following table summarizes information in this regard from Section 6.3 of the PSD application (Table 6-2, p. 6-15).

Table 7-1 Soils and Vegetation Results

Pollutant	Modeled Averaging Time	Predicted Concentration *(µg/m3)*	Background Concentration *(µg/m3)*	Total Concentration *(µg/m3)*	USEPA AQRV Screening Concentration *(µg/m3)*	USEPA AQRV Screening Averaging Time
SO2	1-Hour	43.3	42	92	917	1-Hour
	3-Hour	29	26	55	786	3-Hour

Pollutant	Modeled Averaging Time	Predicted Concentration (μg/m3)	Background Concentration (μg/m3)	Total Concentration (μg/m3)	USEPA AQRV Screening Concentration (μg/m3)	USEPA AQRV Screening Averaging Time
	Annual	0.11	13	13.11	18	Annual
NO2	1-Hour	118	140	258	3,760	4 and 8-Hour
					564	Weekly
	Annual	0.6	26	26.6	94	Annual
PM10	24-Hour	3.9	99	103	N/A	24-Hour
	Annual	0.6	54	54.6	N/A	N/A
CO	8-Hour	387	2,485	2,872	1,800,000	N/A
H2S	1-Hour	23	N/A	23	28,000	4-Hour

For most types of soils and vegetation, ambient concentrations, modeled concentrations only, of criteria pollutants below the secondary NAAQS will not result in harmful effects because the secondary NAAQS are set to protect public welfare, including animals, plants, soils, and materials. The modeled maximum concentrations of SO2, NO2, PM2.5 and PM10 are also significantly below the secondary NAAQS that have been established by EPA:

- secondary 3-hour NAAQS for SO2 = 1,300 μg/m3
- secondary annual NAAQS for SO2 = NA
- secondary 1-hour NAAQS for NO2 = NA
- secondary annual NAAQS for NO2 = 100 μg/m3
- secondary annual NAAQS for PM2.5 = 15 μg/m3
- secondary 24-hour NAAQS for PM2.5 = 35 μg/m3
- secondary annual NAAQS for PM10 = 150 μg/m3, and
- secondary 24-hour NAAQS for PM10 = 150 μg/m3

NA = No secondary standard has been established.

Additionally, comparing the model concentration plus the background concentration to EPA screening AQRVs would also indicate that the project's impact on soil and vegetation would not be significant.

In summary, based on the District's consideration of the information and analysis provided by the applicant, and other relevant information, the District does not believe that emissions associated with the Project will generally result in adverse impacts to soils or vegetation.

7.2 Visibility Impairment

The additional impact analysis also evaluates the potential for visibility impairment (e.g., plume blight) associated with HECA. Using procedures from EPA's Workbook for Plume Visual Impact Screening and Analysis, the potential for visibility impairment is characterized for:

- Class I areas located within 50 km of the proposed HECA; and
- Class II areas identified as potentially sensitive state or federal parks, forests, monuments, or recreation areas.

There are no Federal Class I areas located within 50 km of the Project site; the nearest Class I area is San Rafael Wilderness (60 km away). For Class II areas, the applicant evaluated visibility impairment for two federal Class II areas within ~50 km of the project site for the following areas. The FLM evaluated the Q/d analysis and determined that the impact from the project would be less than significant.

- Sequoia National Forest, 54 kilometers away, and
- Los Padres National Forest, 49 kilometers away from HECA.

EPA Region IX since has requested that a Class II visibility analysis be performed. Because EPA has not yet established a quantitative visibility impairment threshold for Class II areas (similar to what exists for Class I areas), the applicant proposed to use the Class I threshold and methodology to demonstrate whether the Class II area, the Elk Hills located approximately 11 kilometers south of the facility, would be affected by visibility impairment from the Project. The applicant concluded that the results of the Level 1 VISCREEN screening analysis for this area are below the established Class I threshold.

Table 7-2 Class II Visibility Results

Maximum Visual Impacts Inside Area Screening Criteria Are Not Exceeded								
Background	Theta	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	142	15	27	2	1.765	0.05	0.013
SKY	140	142	15	27	2	0.532	0.05	-0.012
TERRAIN	10	84	11	84	2	1.932	0.05	0.019
TERRAIN	140	84	11	84	2	0.291	0.05	0.01

7.3 Growth

The growth component of the additional impact analysis involves a discussion of general commercial, residential, industrial, and other growth associated with the HECA. This analysis considers emissions generated by growth that will occur in the area due to the source. In conducting this review, the applicant focused on residential, commercial and industrial growth that is likely to occur to support the source under review including, for example, employment expected during construction and operations and potential growth impacts associated with such employment, such as impacts to local population and housing needs.

For the periods of construction and plant operations, the applicant provided a discussion of potential growth impacts in Section 6.4 of its PSD application submitted to the District in May

2012. This information included a discussion of the socioeconomics of the project. Topics included population, housing, economic base, and employment.

During the construction and commissioning phase, the applicant estimates a required 200 Full-time workers, with a peak workforce of 2,500 workers in the 49 month of construction. During construction, these workers are expected to temporarily lodge within the project vicinity; following construction, the nonlocal workers are expected to return to their existing residences. During commercial operations, 200 full-time employees are expected. It is anticipated that approximately **60** percent of operations employees will originate from the **Kern** County labor force. The remaining employees will originate from outside **Kern** County. Of the **40** percent non-local workers (**80** workers), it is assumed for the purposes of this analysis that half (**40** employees) will relocate to **Kern** County.

Based on U.S. Census data for 2010, the population of Kern County is 839,631; therefore, the Project will not cause any significant population increases or associated growth (U.S. Census Bureau, 2012). The other half (40 employees) will commute on a daily or weekly basis. The Project's impacts with regard to land use planning and public policy will be minimal. The Project is consistent with the development standards for the Exclusive Agriculture zoning district. The use of the 453-acre Project Site will change from agricultural use to power generation and manufacturing of low-nitrogen- based products.

In summary, based on our consideration of the information and analysis provided by the applicant, the District does not expect the Project to result in any significant growth.

8 District Rule 2201 – Air Quality

District Rule 2201 requires an examination of the impacts of the proposed project on ambient air quality. The project must demonstrate, using air quality models, the facility's emissions of the regulated air pollutants would not cause or contribute to a violation of:

(1) the applicable NAAQS,
(2) the applicable CAAQS

These sections of this report include a discussion of the relevant background data and air quality modeling, and District's conclusion that the Project will not cause or contribute to an exceedance of the applicable NAAQS or CAAQS, and is otherwise consistent with District Rule 2201 requirements.

8.1 Introduction

Under District regulation, a permit evaluation for a project that triggers public notice (District Rule 2201) must include an air quality analysis demonstrating that the facility's emissions of the regulated air pollutants will not cause or contribute to a violation of the applicable NAAQS or CAAQS. Public notice is triggered when an application which includes a new emissions unit or modified unit with a Potential to Emit greater than 100 pounds during any one day for any one affected pollutant. Once public notice is triggered all units including those that do not trigger public notice are assessed.

The air quality assessment is evaluated for all regulated criteria pollutants irrelevant of the District's attainment status.

8.2 NAAQS and CAAQS Analysis

If an analysis demonstrates that the ambient concentration impact resulting from the project's emissions plus a monitored background concentration is less than the NAAQS and/or CAAQS, then further analysis is generally not required. If a preliminary analysis demonstrates that the ambient concentration impact resulting from the project's emissions plus a monitored background concentration is greater than the NAAQS and/or CAAQS, additional analysis is required. In this case, the ambient concentration impact of the project by itself is compared to the Significant Impact Level (SIL) to determine if the project's ambient concentration contributes significantly to a violation of a NAAQS and/or CAAQS.

Required model inputs characterize the various emitting units, meteorology, and the land surface, and a define set of receptors (spatial locations at which to estimate concentrations, typically out to 2-10 km from the facility). Modeling should be performed in accordance with District guidance and EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W).

8.2.1 Additional Modeling Requirements

The following are additional general modeling requirements that should be considered as per District Rule 2201 compliance.

- Include a Good Engineering Practice (GEP) stack height analysis, to ensure that
  c) Downwash is properly considered in the modeling, and
  d) Stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.
- May include initial "load screening," in which a variety of source operating loads and ambient temperatures are modeled, to determine the worst-case scenario for use in the rest of the modeling for NAAQS & CAAQS.
- At a minimum source parameters based on normal operating conditions should be used

8.2.2 Background Ambient Air Quality

District regulations require the air quality analysis to contain air quality monitoring data as needed to assess ambient air quality in the area for regulated pollutants for which there are NAAQS and/or CAAQS that may be affected by the source. In addition, for demonstrating compliance with the NAAQS and/or CAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, as determined by the District, so that the total concentration accounts for all contributions to current air quality.

Ambient air concentrations of ozone (O3), NO2, PM10 and PM2.5 are recorded at monitoring stations throughout the San Joaquin Valley. In order to select the appropriate monitoring station the area surrounding the project site must be first evaluated. The area immediately surrounded the Project site can be characterized as being rural with farmland to northwest, north, east (near the project site and non-developed areas further out) and mountains to the west and south of the project site, see Figure 6-2 in Section 6.4 above. The only major industrial sources are located south of the project site consisting of oil & gas production (~ 4.0 km) and power generation operations (~ 8.0 km).

The monitoring station in Kern County that is closest to the Project Site is the Shafter–Walker Street Station located within 13 miles (21 kilometers) from the Project Site. This station measures ozone (O3) and NOX/NO2 concentrations, and is the most representative station to characterize background conditions for these pollutants near HECA.

The Bakersfield ─ 5558 California Avenue station is the next closest station and the closest that measures all pollutants except SO2 and CO. This station is located approximately 20 miles (32 kilometers) to the east of the Project site, and provides the best representation of the background levels for PM10 and PM2.5 for the area near HECA. In addition, it is the only station that measures these pollutants with adequate data capture within the San Joaquin Valley portion of Kern County.

The Bakersfield ─ Golden State Highway station is the only station in Kern County that measures CO. This station was closed early in 2010; thus the most recent measurements available for this station are for 2007–2009, as 2010 data did not have suitable data capture.

The only station in the SJVAB that monitors SO2 is the CARB station at First Street in Fresno, located approximately 102 miles (164 kilometers) to the north. Sulfur dioxide data have only been recorded in Fresno County for 6 of the last 10 years (2003, 2007, 2008, 2009, 2010, 2011), a practice that is justified by the low levels that have been recorded for this pollutant where and when measurements have been made.

Table 8-1 below describes the maximum background concentrations, from the most recent available 3 year period of data collection, for which there are NAAQS & CAAQS that may be affected by the Project's emissions. Use of this method effectively assumes that the highest recently recorded pollutant concentrations for each averaging period are occurring during every such period over the 5-year meteorological input record. This static high background is then paired with modeled results.

Table 8-1 CAAQS, NAAQS, & Background Concentration

Ambient Air Quality Standards				
Pollutant	**Averaging Time**	**California Standards**	**National Standards Primary**	**Background Concentration** ($\mu g/m^3$)
		Concentration		
Respirable Particulate Matter (PM10)	24 Hour	50 $\mu g/m^3$	150 $\mu g/m^3$	99
	Annual Arithmetic Mean	20 $\mu g/m^3$	--	54
Fine Particulate Matter (PM2.5)	24 Hour[1]	--	35 $\mu g/m^3$	196
	Annual Arithmetic Mean	12 $\mu g/m^3$	15 $\mu g/m^3$	22
Carbon Monoxide (CO)	1 Hour	23 mg/m^3	40 mg/m^3	4,581
	8 Hour	10 mg/m^3	10 mg/m^3	2,485
Nitrogen Dioxide (NO2)	1 Hour[2]	339 $\mu g/m^3$	188 $\mu g/m^3$	140
	Annual Arithmetic Mean	57 $\mu g/m^3$	100 $\mu g/m^3$	26
Sulfur Dioxide (SO2)[3]	1 Hour	655 $\mu g/m^3$	196 $\mu g/m^3$	42
	3 Hour[4]	---	1300 $\mu g/m^3$	26
	24 Hour	105 $\mu g/m^3$	365 $\mu g/m^3$	13

1 - The PM2.5 24-hr value is the 98th percentile averaged over three years rather than the maximum
2 - The NO2 1-hr value is the 98th percentile averaged over three years rather than the maximum
3 - The SO2 annual standard is replaced by the more stringent SO2 1-hour standard
4 – No primary standard exist for SO2 3-hour standard. Value used is for the secondary standard

8.2.3 Modeling Methodology

The applicant modeled the impact of the project on the NAAQS and/or CAAQS using AERMOD in accordance with District guidance and EPA's GAQM (Appendix W of 40 CFR Part 51). Unlike requirements for PSD no screening method is available. The modeling analyses included the maximum air quality impacts during normal operations using the appropriate emissions during each averaging period.

8.2.3.1 Model Selection

As discussed in the PSD Application, the model selected for analyzing air quality impacts in Class II areas is EPA's preferred dispersion model AERMOD [Ver. 12060], along with AERMAP for terrain processing and AERMET for meteorological data processing. This is in accordance with the default recommendations in the District guidance and EPA's GAQM, Section 4.2.2 on Refined Analytical Techniques.

8.2.3.2 Meteorological Inputs

8.2.3.2.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. SJVAPCD provided the surface meteorological data collected for a five-year consecutive period (from 2006 – to 2010) at the Bakersfield Meadows Field Airport meteorological station maintained by the FAA.

The District processed these data using EPA's AERMET data processor and the District meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). The meteorological station is located on the northern end of the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site, with no intervening structures, hills, or water bodies that might significantly affect meteorological conditions. The project site, the meteorological site and the "area of interest" are located inland and close to each other.

For analyzing the representativeness of the meteorological dataset, the area of interest includes:

- the SIA where screening modeling predicts the Project's pollutant impact to be greater than the SILs, and
- Also includes the sources and receptors used in the modeling.

Other nearby surface meteorological sites were examined, but the Bakersfield Meadows Field Airport station had sufficient data completeness, is the closest, and is the most representative with no intervening high ground between the Project site and the meteorological tower. District believes that the chosen from 2006 – to 2010 Bakersfield Meadows Field Airport data is the most representative for the proposed project analysis. Further discussion of the meteorological data used in the analysis is given in the following section on land characteristics. **Please Note**: The other nearby sites (Fellows and Missouri Triangle) are considered prognostic datasets generated from MM5 data and at the current time are not acceptable by EPA; even though the District would allow their used for the purpose of District Rule 2201. The District accepts the use of the selected meteorological data to streamline the process of assessing the NAAQS & CAAQS.

8.2.3.2.2 Upper Air Data

For upper air data, the District selected (from 2006 – to 2010) the upper air site located in Oakland, California, located approximately 227 miles (366 km) northwest of the Project site as being the most representative site available that had data complete enough to use. No other upper air meteorological monitoring stations are located in the San Joaquin Valley Air Basin.

8.2.4 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

1) via elevation within AERMOD to assess plume interaction with the ground;
2) via a choice of rural versus urban algorithm within AERMOD; and
3) via specific values of AERMET parameters that affect turbulence and dispersion, namely surface roughness length, Bowen ratio, and albedo. The surface roughness length is related to the height of obstacles to the wind flow and is an important factor in determining the magnitude of mechanical turbulence. The Bowen ratio is an indicator of surface moisture. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption.

The applicant used terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data at a horizontal resolution of 30 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83, Zone 11). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

The applicant used surface roughness values in the modeling inputs developed by SJVAPCD. The District followed EPA's “AERMOD Implementation Guide” (2009 version) and the District’s Guidance entitled “Procedure for Downloading & Processing NCDC Meteorological Data” in using EPA's AERSURFACE processor with the National Land Cover Data 1992 archive to determine surface characteristics for AERMET. The surface roughness characteristics are representative of the area surrounding the site where the meteorological data is collected. The District also used the criteria described in Section 3 (Representativeness) from EPA’s Meteorological Monitoring Guidance for Regulatory Modeling Applications (2000). AERSURFACE uses a Land Use data base from 1992. In addition, SJVAPCD reviewed recent aerial photos for the area, which show that the Bakersfield Meadows Field Airport meteorological tower is surrounded by a light industrial, residential, and rural area.

Figure 8-1 Bakersfield Meadows Field Airport

The applicant did a qualitative comparison of the following factors from the Meteorological Monitoring Guidance (p.3-3) recommended for consideration for siting:

- Proximity
- Height of measurement
- Surface

The Bakersfield Airport is the closest full-time meteorological recording station to the Project Site. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are at approximately the same elevation. Additionally, there are no significant terrain features separating the Bakersfield Airport from the Project Site that would cause significant differences in wind or temperature conditions between these respective areas.

8.2.5 Receptors Grid

Receptors in the model are geographic locations at which the model estimates concentrations. The applicant placed receptors such that they have good area coverage and are closely

spaced enough so that the maximum model concentrations can be found. At larger distances, spacing between receptors may be greater than it is close to the source, since concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project boundary.

The applicant used a Cartesian coordinate receptor grid to provide adequate spatial coverage surrounding the project area, to identify the extent of significant impacts, and to identify the maximum impact location. In the analyses, the applicant placed receptors using the following telescoping grid out to 10 km, as seen in Figure 4-1 & 4-2 of the Project application:

- 25-meter spacing along the property line and extending from the property line out 100 meters;
- 50-meter spacing from 100 to 250 meters beyond the property line;
- 100-meter spacing from 250 to 500 meters beyond the property line;
- 250-meter spacing from 500 meters to 1 kilometer beyond the property line;
- 500-meter spacing from 1 to 2 kilometers beyond the property line; and
- 1,000-meter spacing from 2 to 10 kilometers beyond the property line.

During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time was located within the portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid was placed around the original maximum concentration point, and the model was rerun. The dense grid used 25-meter spacing and extended to the next grid point in all directions from the original point of maximum concentration. The only dense refined receptor grid that was needed in the current modeling analysis occurred for 24-hour SO2 operational modeling, where a dense grid was placed in the hills southwest of the Project site. Details may be seen in the model input files included in the electronic files submitted with this PSD Application.

8.2.6 Load Screening and Source Parameters

The applicant performed initial “load screening” modeling, in which nine source operating loads and ambient temperatures were modeled, to determine the “worst case” stack parameter scenario for use in the rest of the modeling, whenever normal operations are considered. At a minimum two loads should be considered: a minimum load of 50% and a maximum load of 100%. The choice of “worst case” can be different for each pollutant and averaging time, because different sources’ emissions respond differently to temperature and flow rate.

For all pollutants and averaging times, screening modeling was performed with maximum emissions and the most conservative stack parameters for each source, regardless of whether all equipment will run at the same time in this worst-case stack parameter and emission configuration. This methodology was performed to determine conservative worst-case off-site impacts without the need of sensitivity modeling for each piece of equipment or time period. Normally, all sources will not run at the same time with their worst-case stack parameters and

emissions. For example, the emergency ancillary equipment (generators, firewater pump) will not all be tested at the same time during a start-up sequence. However, if the most conservative impact scenario complied for the CAAQS and NAAQS, the equipment was kept in the modeling with maximum emissions and the most conservative stack parameters to eliminate the need for sensitivity modeling iterations. Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application.

More refined modeling was completed for several pollutants to more accurately depict the activities occurring concurrently for short averaging times. Sensitivity modeling was completed for CO 1-hour, and it was determined that the CTG/HRSG shut-down scenario (20 percent load burning natural gas) gave higher impacts than the CTG/HRSG starting up scenario. However, the maximum CO 8-hour impact was determined to occur during CTG/HRSG start-up mode when other sources are operating for that duration of time. It was determined that the Feedstock dryer gave higher short-term SO2 impacts in operations mode than in start-up or shut-down mode, while all other maximum pollutant impacts for the Feedstock dryer occurred during Feedstock dryer start-up mode. Finally, maximum NO2 1-hour NAAQS impacts occur when the CTG/HRSG and Feedstock dryer are operating in on-peak power mode rather than off-peak power mode.

Table 8-2 Source Stack Parameters

Source	Operating Condition Associated with Emission Rate	Stack Ht.	Temperature	Exit Velocity	Stack Diameter
		(ft)	*(°F)*	*(ft/sec)*	*(ft)*
HRSG Stack	Normal On-Peak Emissions (Case 1)	213	200	53.81	23
Feedstock Dryer	Normal On-Peak Emissions (Case 1)	305	200	19.16	16
Tail Gas Thermal Oxidizer Stack	Normal operations	165	1200	50.93	2.5
Auxiliary Boiler	Normal operations	80	300	30.18	4.5
Rectisol® Flare	Annualized emissions, start-up flaring (effective stack height and diameter)	217.83	1831.73	65.62	0.87
Gasification Flare	Annualized emissions, start-up and shut-down flaring (effective stack height and diameter)	219.63	1831.73	65.62	1.22
SRU Flare	Normal Operations, Pilot (effective stack height and diameter)	215	1831.73	65.62	0.32
Nitric Acid Plant Stack	Normal operations	145	239	17.11	8
Emergency Diesel Generator 1	Annualized emissions	20	760	221.05	1.2
Emergency Diesel Generator 2	Annualized emissions	20	760	221.05	1.2
Emergency Diesel	Annualized emissions	20	850	155.91	0.7

Firewater Pump					
Ammonia Synthesis Plant Start-up Heater	Annualized emissions	80	300	18.71	3.5

8.2.7 Good Engineering Practice (GEP) Analysis

The applicant performed a Good Engineering Practice (GEP) stack height analysis, to ensure that:

a) downwash is properly considered in the modeling, and
b) stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.

As is typical, the GEP analysis was performed with EPA's BPIP Prime (Building Profile Input Program) software, which uses building dimensions and stack heights as inputs. All stacks in the HECA Project will be less than or equal to the GEP default height of 65 meters, except for the Feedstock dryer, three flares (SRU, Gasification, Rectisol), and the CO2 vent. Based on the analysis, the applicant showed that the GEP stack heights for the Feedstock Dryer and CO2 Vent were greater than 65 m (213 ft), which is greater than the planned actual height of 92.9 m (304.8 ft) and 79.2 m (259.8 ft).

The flares are not within 5 times L (138.5 meters) of the gasification structure or any other structure that is large enough to create downwash for the flares in BPIP. It is important to note that the flares will be built at 76.2 meters tall for safety from a project engineering perspective. However, a 65-meter stack height, or GEP, was used to calculate specific effective stack heights for each flare modeling scenario based on the flare's heat release rate during that modeling scenario. The effective stack height is the height of the stack plus the height above the stack where the flare flame ends and a plume can begin. The effective stack parameters were calculated using the SCREEN3 technique, and were input into the AERMOD model. Therefore, the lower 65 meter stack height was used as the stack height in the calculation of the effective stack heights for the flares, rather than the actual stack height.

The applicant also showed that the GEP stack height for the other equipment was similarly greater than the planned heights. So, for all emitting units, the applicant used the planned actual stack heights for inputs in AERMOD modeling, and included wind direction-specific Equivalent Building Dimensions to properly account for downwash.

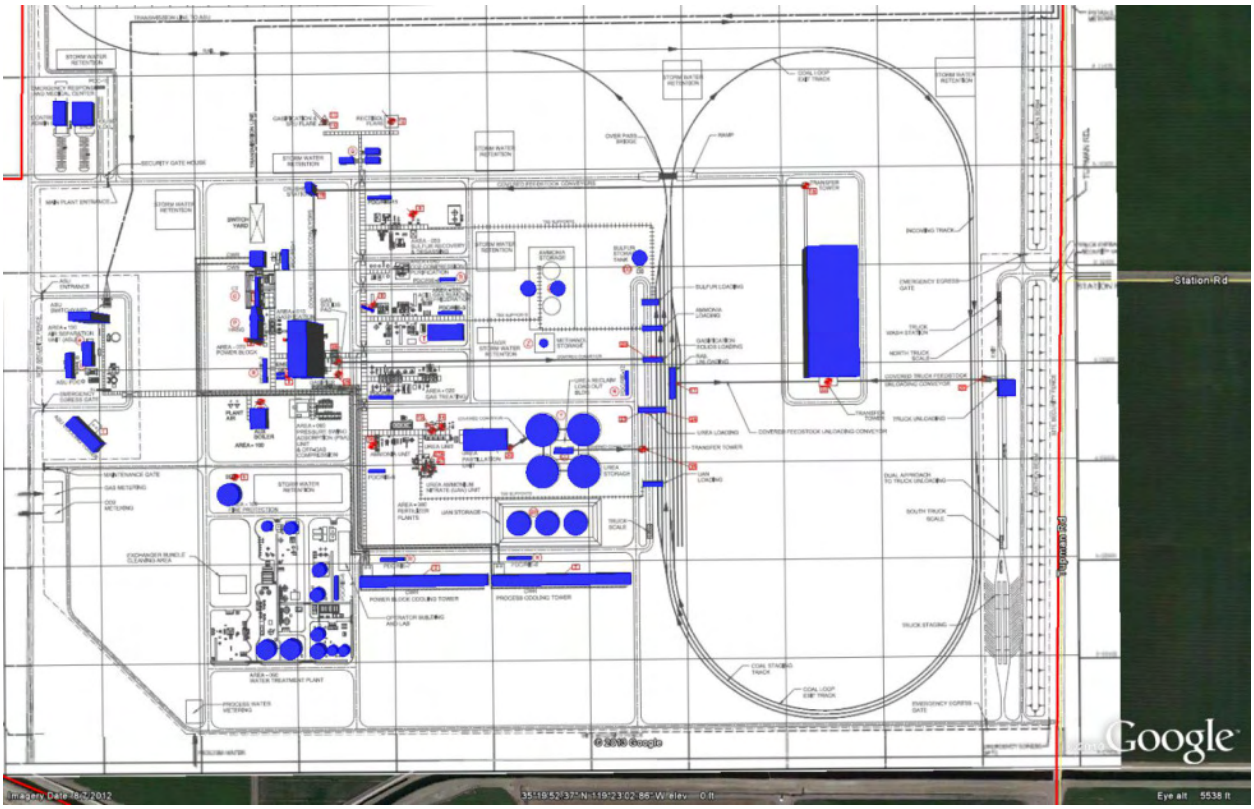


Figure 8-2 Onsite Structures (Blue Objects)

8.2.8 Preliminary Analysis

District Rule 2201 requires an air quality impact analysis be performed when a unit or project triggers public notice. Public Notice is triggered when an application which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one affected pollutant. This threshold is used as a screening tool to determine which projects need further review.

Applicable project emissions are shown in Table 8-3 (provided by the processing engineer). As shown in Table 8-3 below, several units are above the public notice threshold of 100 lbs per day. Therefore, this project triggers a refined ambient air quality analysis (AAQA) for units under the current application.

Table 8-3 Daily Emissions By Permit ID

Permit ID	Unit Description	Lbs / Day*					Public Notice Triggered
		SO2	NOx	CO	PM10	VOC	
Public Notice Thresholds		***100 lbs of Any Pollutant***					
17-0	Coal Handling				4		NO
18-0	Petcoke Handling				17		NO
19-0	Rec. & Blending				1		NO
20-0	Grinding				5		NO
21-0	Gasification System	0		24		66	NO

Permit ID	Unit Description	Lbs / Day*					Public Notice Triggered
		SO2	NOx	CO	PM10	VOC	
Public Notice Thresholds		*100 lbs of Any Pollutant*					
22-0	Gasification Solid Handling				4		NO
23-0	Sulfur Recovery Unit	4,852	997	833	32	23	YES
24-0	CO2 Recovery and Vent System			11,911		677	YES
25-0	NG Fired Auxiliary Boiler	15	31	189	26	20	YES
26-0	CTG/HRSG stack	113	818	624	360	142	YES
26-0	Feedstock dryer stack	22	106	77	34	14	YES
27-0	Cooling Tower Serving Power Block and Process Units				88		NO
28-0	Cooling Tower Serving Air Separation Unit				5		NO
29-0	Cooling Tower Serving Power Block				52		NO
30-0	Gasification Flare	80	2,399	18,283	238.2	51	YES
31-0	SRU Flare	442	59	70	3	1	YES
32-0	Rectisol Flare	120	234	276	10	5	YES
33-0	Ammonia Synthesis Plant	4	15	50	7	5	NO
34-0	Urea Unit				0		NO
35-0	Nitric Acid Unit		100				YES
36-0	Ammonium Nitrate Unit				5		NO
37-0	Urea Storage and Handling Operation				6		NO
38-0	Diesel-Fired Emergency Engines Powering Electrical Generators	1	77	402	11	46	YES
39-0	Diesel-Fired Emergency Engines Powering Electrical Generators	1	77	402	11	46	YES
40-0	Diesel-Fired Emergency Engine Powering Firewater Pump	0	44	77	0	4	NO

* Emissions have been rounded to the nearest whole number

8.2.9 Refined Analysis

A refined analysis demonstrates that the ambient concentration impact resulting from the project's emissions plus a monitored background concentration is less than the NAAQS and/or CAAQS, further analysis is generally not required. If a preliminary analysis demonstrates that the ambient concentration impact resulting from the project's emissions plus a monitored background concentration is greater than the NAAQS and/or CAAQS, additional analysis is required. In this case, the ambient concentration impact of the project by itself is compared to

the Significant Impact Level (SIL) to determine if the project's ambient concentration contributes significantly to a violation of a NAAQS and/or CAAQS

8.2.9.1 NO2-Specific Issues

While the new 1-hour NO2 NAAQS is defined relative to ambient concentrations of NO2, the majority of NOx emissions from stationary sources are in the form of nitric oxide (NO) rather than NO2. Appendix W notes that the impact of an individual source on ambient NO2 depends in part "on the chemical environment into which the source's plume is to be emitted" (see Appendix W, Section 5.1.j). Because of the role NOx chemistry plays in determining ambient impact levels of NO2 based on modeled NOx emissions, Section 5.2.4 of Appendix W recommends a three-tiered screening approach for NO2 modeling. Later guidance documents issued by EPA expand on this approach. Tier 1 assumes full conversion of NO to NO2. Tiers 2 and 3 are refinements of the amount of conversion of NO to NO2. The applicant used the Tier 3 Plume Volume Molar Ratio Method (PVMRM) option in AERMOD, which simulates the interaction of NO with ambient O3 to form NO2. The PVMRM determines the conversion rate for NOx to NO2 based on a calculation of the NOx emitted into the plume, and the number of O3 moles contained within the volume of the plume between the source and receptor. In addition to requiring monitored ozone, the method requires specification of an in-stack NO2/NOX ratio. The following presents a discussion of the in-stack NO2/NOx ratios used in PVMRM for the proposed emissions units and nearby sources for the cumulative impact analysis.

A. In-Stack NO2/NOx Ratio

Defining source-specific in-stack NO2/NOx ratios is part of the refinement of the Tier 3 PVMRM. An in-stack NO2/NOx ratio of 0.50 is the default value and can be used without further justification.

For the emergency generators, firewater pump, ammonia startup heater, and auxiliary boiler, the NO2/NOX in-stack ratios were obtained from the SJVAPCD 2010 draft guidance document, Assessment of Non-Regulatory Options in AERMOD Specifically OLM and PVMRM and the CAPCOA Modeling Compliance of the Federal 1-hour NO2 NAAQS. For the emergency generators and fire water pump, an in-stack ratio of 0.2 was used from the "IC Engines (Diesel)" category. The ammonia start-up heater used an in-stack ratio of 0.32 from the "Heaters (NG)" category. For the auxiliary boiler, an in-stack ratio of 0.1 was used from the "Boilers (NG)" category.

Limited information is available regarding in-stack NO2/NOX ratios for thermal oxidizers and flares. The exhaust from the thermal oxidizer or flares will have very little to no residence time in the stack, so almost no conversion of nitrogen oxide (NO) to NO2 is expected. For these sources, it was conservatively assumed that 10 percent of the NOX will be NO2.

No data exist for the NO2/NOX in-stack ratio for turbines burning hydrogen-rich fuel or the associated Feedstock dryer. The turbine vendor expects the NO2/NOX in-stack ratio will be similar to turbines that burn natural gas. Based on the in-stack NO2/NOX ratio of 0.091 for a natural gas turbine as determined by SJVAPCD guidance, and accounting for the conversion of NO to NO2 across the oxidation catalyst that could be

as high as 20 percent (NO2/NOX ratio 0.2), HECA proposes to use the conservative NO2/NOX in-stack ratio of 0.3 for all turbine and Feedstock dryer operating conditions. Neither the turbine nor oxidation catalyst vendor could provide written documentation regarding the NO2/NOX in-stack ratio, although this ratio was their professional engineering estimate. Emissions from the nitric acid plant will be cleaned before being discharged to the atmosphere by catalytic decomposition and reduction of both nitrous oxide (N2O) and NOX. The N2O emissions are treated in a tertiary reduction system, in a reducing catalyst that uses high temperature rather than a reducing agent, to convert 95 percent of the remaining N2O emission to molecular nitrogen (N2) and nitric oxide (NO). The NOX emissions (including the NO formed in the N2O converter) are then reduced in one or more selective catalytic reduction (SCR) units, with injected ammonia as a reducing agent, as is typical for NOX control in flue gas systems. The nitric acid unit vendor and Project design engineers estimate that approximately 50 percent of the NO converts to NO2 in the exhaust, therefore an in-stack ratio of 0.5 was used. Table 8-4 presents the resulting PVMRM in-stack NO2/NOx ratios.

Table 8-4 In-Stack NO2/NOx Ratios for Project Units

Source / Emission Units	NO2 / NOx Ratio
HRSG Stack	0.3
Feedstock Dryer	0.3
Tail Gas Thermal Oxidizer Stack	0.1
Auxiliary Boiler	0.1
Rectisol® Flare	0.1
Gasification Flare	0.1
SRU Flare	0.1
Nitric Acid Plant Stack	0.5
Emergency Diesel Generator 1	0.2
Emergency Diesel Generator 2	0.2
Emergency Diesel Firewater Pump	0.2
Ammonia Synthesis Plant Start-up Heater	0.32

The in-stack ratios used for the proposed units were based on the best available data known at the time the project was proposed and modeled. Currently there is still limited or no data available for some of the processes/fuel types that are proposed at the facility.

B. NO2 monitor representativeness/conservativeness
As mentioned above, the applicant chose the Shafter–Walker Street Station monitor for background NO2 concentrations. This monitor is 13 miles from the HECA site.

C. O3 background Monitor Representativeness

The applicant has indicated that since O3 is a regionally-formed pollutant, the nearness of the monitoring site to the Project is the most important criterion for representativeness. The Shafter–Walker Street Station monitor is 13 miles away from the HECA site, and the District agrees that it is adequately representative.

D. Missing O3 data procedure
Ozone data used in this analysis was prepared by the District using a monthly hour of the day fill method. This provides a reasonable and conservative procedure for filling in missing ozone values.

E. Combining Modeled and Monitored Values
The applicant proposed to combine each modeled concentration with the background concentration from the corresponding hour ("hour-by-hour" approach) pairing. The applicant correctly used the first highest values from the distribution for each temporal combination. (The EPA March 2011 memo's "first-tier" approach uses the 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data as a uniform background contribution but also mentions the above procedure as a suggested temporal pairing option on p.20.) This procedure is based on a conservative assumption.

The District believes that the applicant's overall approach to the 1-hour NO2 analysis for the HECA, including the emission inventory, background concentrations of NO2 and O3, and method for combining model results with monitored values, is adequately conservative..

8.2.9.2 Refined AAQA Results

The results of the refined AAQS analysis for HECA's operations are shown in Table 8-5. The analysis demonstrates that emissions from HECA will not cause or contribute to exceedance of a NAAQS and/or CAAQS for any affected pollutant.

The District also considered additional information to ensure that the Project would not be responsible for causing a new NAAQS and/or CAAQS exceedance outside this modeling area. The District also considered the emission reduction credits being surrendered by the applicant if the project exceeds any NAAQS, CAAQS, or SIL threshold when making its determination. The District concludes the Project's expected emissions would not create any new NAAQS and/or CAAQS exceedances.

Table 8-5 Refined AAQA Results

NAAQS Pollutant & Averaging Time	Modeled Impacts	Background	Total	NAAQS / CAAQS		Significant Impact Level (SIL)	Project Impact Significant?	
	ug/m3	*ug/m3*	*ug/m3*	*ug/m3*		*µg/m3*	AAQS	SIL
CO, 1-hour	1,849.6	4,581	6,430	23,000	40,000	2000	No	No
CO, 8-hour	386.8	2,485	2,872	10,000	10,000	500	No	No
NO2, 1-hour (CAAQS)	91	140	231	---	339		No	No
NO2, 1-hour (NAAQS)	118	(Paired)	118	188	---	7.5	No	No

NO2, annual (CAAQS)	0.6	26	27	---	57	1	No	No
NO2, annual (NAAQS)	0.6	26	27	100	---	1	No	No
SO2, 1-hour	31.7	42	74	196	655	7.8	No	No
SO2, 3-hour	259.6	26	285.6	1,300	---	25	No	No
SO2, 24-hour	43.3	13	56.3	365	105	5	No	No
PM10, 24-hour	3.9	99	103	50	150	5	Yes	No
PM10, annual	0.6	54	55	20	---	1.0	Yes	No
PM2.5, 24-hour	2.3	196	198	35	---	1.2[1]	Yes	Yes
PM2.5, annual	0.5	22	23	15	15	0.3	Yes	Yes

As noted in Table 8-5, all pollutants except PM2.5 24-hour and annual are below either the NAAQS/CAAQS or the SIL thresholds. As per District Rule 2201, mitigation may be considered when evaluating a projects ambient air quality impact. To ensure, to the maximum extent possible, that a facility's emissions do not adversely impact air quality the District requires that it fully offsets any air quality impact. Therefore, since emissions from PM2.5 24-hour and annual exceed the NAAQS/CAAQS and SIL thresholds HECA will be required to fully offset, down to zero, their PM2.5 emissions.

9 District Rule 4201 – *Nuisances (Health Risk Analysis)*

District Rule 4201 requires that an assessment be performed on a unit by unit basis, Project basis and on a facility-wide basis to show complies with Assembly Bill 2588 Air Toxic "Hot Spots" Act requirements, better known as AB2588. If a preliminary analysis (Prioritization) demonstrates that

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold then generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required using District approved models including but not limited to District screening assessment tools, AERMOD, and CARB's HARP program. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 2-5 km from the facility). Modeling should be performed in accordance with District, OEHHA, and EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W).

If a refined assessment is greater than one in a million but less than 10 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, Project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million Toxic Best Available Control Technology (TBACT) must be implemented. In most cases Best Available Control Technology (BACT) is considered TBACT.

Carcinogenic impacts greater than 10 in one million or greater than 1.0 for either the Acute or Chronic hazard indices is considered significant and may not be permitable. In special circumstance the Air Pollution Control Office may approve a project determined to be significant; if it can be demonstrated that the project is essential to public safety and more harm to the public may occur from denying the project than from approving it.

9.1 Prioritization

The prioritization methodology used by the District was developed by the Facility Prioritization Guidelines of the AB 2588 Risk Assessment Committee of the California Air Pollution Control Officers Association in 1990. The guidance document can be downloaded from ARB at http://www.arb.ca.gov/ab2588/RRAP-IWRA/priguide.pdf.

The prioritization methodology has two basic methods that can be used to determine a source's potential impact on nearby receptors. The first is the "Emissions and Potency" method which relies on the quantity of a specific pollutant and the pollutant's specific potency (tendency to cause harm) in conjunction with the distance a source is from a receptor to calculate a score or potential for exposure.

The second method, “Dispersion Adjustment”, is similar to the first method except that the stack height is also included as a parameter in the calculations to derive the prioritization score. Both prioritization methodologies look at three aspects of exposure 1) Acute short term non-carcinogenic risk [1-24 hours], 2) Chronic long term non-carcinogenic risk [24 hours to 1 year], and 3) Carcinogenic risk over a 70 year period.

For the purpose of this assessment the word carcinogenic refers to those compounds that have been identified by the Office of Environmental Health hazard Assessment (OEHHA) as having the potential of cause cancer.

The applicant did not perform a prioritization and instead conducted a refined assessment. This is consistent with District procedures since the project is considered a new major source. This would ensure that the exposures from toxic pollutants are fully evaluated, to actual receptors, in the vicinity of the project site.

9.2 Screening and Refined Assessment

If modeling is required after implementing a screening technique, two modeling options may be available depending on the reviewing agencies requirements. The first option is a screening model that uses conservative modeling assumptions to estimate impacts or it may be a spreadsheet that was derived from a screening/refined model using conservative assumptions.

The second option is to use a refined model which will require more resources and time. This is due to the facility and source specific information required to perform a given run.

The determination of which option is used will mainly be based on the following:

1. Is there a screening method available for the scenario under review?
2. Is the conservative screening method acceptable to the reviewing agency?
3. Is the meteorological data used to develop the screening method acceptable?
4. Are the source parameters used in the screening method acceptable?

If the answers to all the questions above are “Yes”, the screening method, for the most part, would be the best choice.

The applicant did not perform a screening assessment and instead conducted a refined assessment. This is consistent with District procedures since the project is considered a new major source. This would ensure that the exposures from toxic pollutants are fully evaluated, to actual receptors, in the vicinity of the project site.

9.3 Modeling Methodology

The applicant modeled the impact of the project using AERMOD in accordance with District OEHHA, and CARB guidance. The modeling analyses included the maximum air quality impacts during normal operations using maximum hourly emissions for the acute HI, annual emissions for the chronic HI, and annual emissions for the cancer risk.

9.3.1 Model Selection

The District requires that AERMOD and HARP be used to analyze health impacts in the areas, along with AERMAP for terrain processing and meteorological data processed by the SJVAPCD. As discussed in the PSD Application the applicant followed these recommendations.

9.3.1.1 Meteorological Inputs

9.3.1.1.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. SJVAPCD provided the surface meteorological data collected for a five-year consecutive period (from 2006 – to 2010) at the Bakersfield Meadows Field Airport meteorological station maintained by the FAA.

The District processed these data using EPA's AERMET data processor and the District meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). The meteorological station is located on the northern end of the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site, with no intervening structures, hills, or water bodies that might significantly affect meteorological conditions. The project site, the meteorological site and the "area of interest" are located inland and close to each other.

For analyzing the representativeness of the meteorological dataset, the area of interest includes:

- the SIA where screening modeling predicts the Project's pollutant impact to be greater than the SIL, and
- Also includes the sources and receptors used in the modeling.

Other nearby surface meteorological sites were examined, but the Bakersfield Meadows Field Airport station had sufficient data completeness, is the closest, and is the most representative with no intervening high ground between the Project site and the meteorological tower. District believes that the chosen from 2006 – to 2010 Bakersfield Meadows Field Airport data is the most representative for the proposed project analysis. Further discussion of the meteorological data used in the analysis is given in the following section on land characteristics. **Please Note**: The other nearby sites (Fellows and Missouri Triangle) are considered prognostic datasets generated from MM5 data and at the current time are not acceptable by EPA; even though the District would allow their used for the purpose of District Rule 2201. The District accepts the use of the selected meteorological data to streamline the process of assessing exposure to toxic pollutants.

9.3.1.2 Upper Air Data

For upper air data, the District selected the (from 2006 – to 2010) upper air site located in Oakland, California, located approximately 227 miles (366 km) northwest of the Project site as being the most representative site available that had data complete enough to use. No other upper air meteorological monitoring stations are located in the San Joaquin Valley Air Basin.

9.3.2 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

1) via elevation within AERMOD to assess plume interaction with the ground;
2) via a choice of rural versus urban algorithm within AERMOD; and
3) via specific values of AERMET parameters that affect turbulence and dispersion, namely surface roughness length, Bowen ratio, and albedo. The surface roughness length is related to the height of obstacles to the wind flow and is an important factor in determining the magnitude of mechanical turbulence. The Bowen ratio is an indicator of surface moisture. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption.

The applicant used terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data at a horizontal resolution of 30 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83, Zone 11). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

The applicant used surface roughness values in the modeling inputs developed by SJVAPCD. The District followed EPA's “AERMOD Implementation Guide” (2009 version) and the District’s Guidance entitled “Procedure for Downloading & Processing NCDC Meteorological Data” in using EPA's AERSURFACE processor with the National Land Cover Data 1992 archive to determine surface characteristics for AERMET. The surface roughness characteristics are representative of the area surrounding the site where the meteorological data is collected. The District also used the criteria described in Section 3 (Representativeness) from EPA’s Meteorological Monitoring Guidance for Regulatory Modeling Applications (2000). AERSURFACE uses a Land Use data base from 1992. In addition, SJVAPCD reviewed recent aerial photos for the area, which show that the Bakersfield Meadows Field Airport meteorological tower is surrounded by a light industrial, residential, and rural area.

Figure 9-1 Bakersfield Meadows Field Airport

The applicant did a qualitative comparison of the following factors from the Meteorological Monitoring Guidance (p.3-3) recommended for consideration for siting:

- Proximity
- Height of measurement
- Surface

The Bakersfield Airport is the closest full-time meteorological recording station to the Project Site. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are at approximately the same elevation. Additionally, there are no significant terrain features separating the Bakersfield Airport from the Project Site that would cause significant differences in wind or temperature conditions between these respective areas

9.3.3 Sensitive Receptors Grid

Sensitive receptors are defined as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large. Additionally, the District includes in

the definition of sensitive receptors locations occupied by groups of individuals that may be more susceptible than the general population to health risks from a chemical exposure and therefore include schools (public and private), day-care facilities, convalescent homes, parks, and hospitals.

Two sensitive receptors exist within 6 miles of the Project (6 miles is the extent of the modeling receptor grid): Elk Hills elementary school, 1.3 miles to the southeast; and the Tule Elk State Natural Reserve, located 1,700 feet to the east of the Project Site. Figure 9-2, Sensitive Receptor Located, shows the location of these sensitive receptors, plus the locations of the nearest residences. A total of 118 residences near the Project Site were included in the modeling. The closest residential neighborhood is in the unincorporated community of Tupman, approximately 2 miles southeast of the Project boundary. There are also additional single-family residences in the immediate Project vicinity, including residences approximately 1,400 feet to the east and 3,300 feet to the southeast of the Project Site. The HRA approach treats all receptors as sensitive receptors.

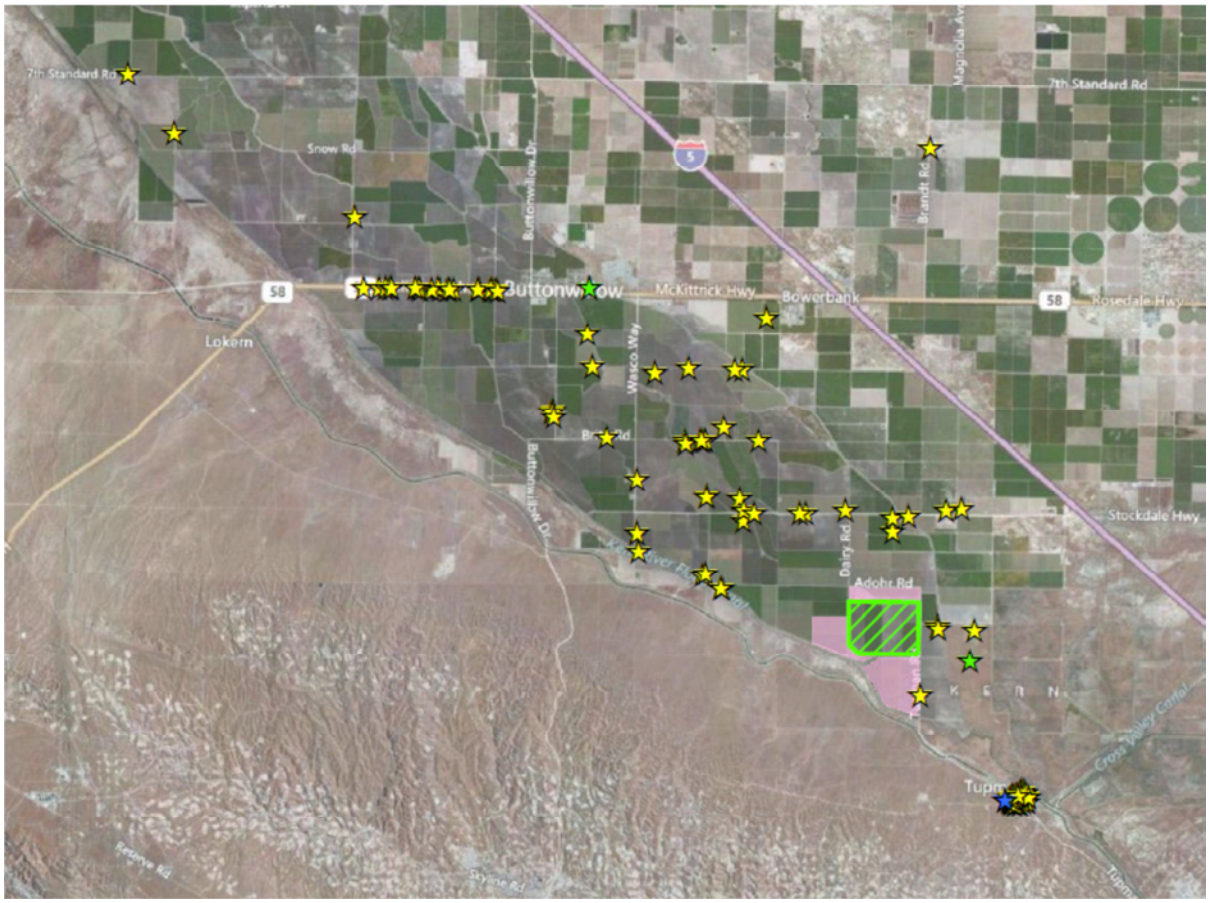


Figure 9-2 Sensitive Receptor Locations

9.3.3.1 Source Parameters

Modeling was performed using the source parameters in the tables below to conservatively estimate the Project's impacts.

Table 9-1 Source Stack Parameters

Source	Operating Condition Associated with Emission Rate	Stack Ht.	Temperature	Exit Velocity	Stack Diameter
		(ft)	*(°F)*	*(ft/sec)*	*(ft)*
HRSG Stack	Normal On-Peak Emissions (Case 1)	213	200	53.81	23
Feedstock Dryer	Normal On-Peak Emissions (Case 1)	305	200	19.16	16
Tail Gas Thermal Oxidizer Stack	Normal operations	165	1200	50.93	2.5
Auxiliary Boiler	Normal operations	80	300	30.18	4.5
Rectisol® Flare	Annualized emissions, start-up flaring (effective stack height and diameter)	217.83	1831.73	65.62	0.87
Gasification Flare	Annualized emissions, start-up and shut-down flaring (effective stack height and diameter)	219.63	1831.73	65.62	1.22
SRU Flare	Normal Operations, Pilot (effective stack height and diameter)	215	1831.73	65.62	0.32
Nitric Acid Plant Stack	Normal operations	145	239	17.11	8
Emergency Diesel Generator 1	Annualized emissions	20	760	221.05	1.2
Emergency Diesel Generator 2	Annualized emissions	20	760	221.05	1.2
Emergency Diesel Firewater Pump	Annualized emissions	20	850	155.91	0.7
Ammonia Synthesis Plant Start-up Heater	Annualized emissions	80	300	18.71	3.5

9.3.4 Health Risk Analysis

Adverse health effects are expressed in terms of cancer or non-cancer health risks. Cancer risk is typically reported as "lifetime cancer risk," which is the estimated maximum increase in the risk of developing cancer caused by long-term exposure to a pollutant identified as being a carcinogen by the OEHHA. The calculation of cancer risk conservatively assumes an individual is exposed continuously to the maximum pollutant concentrations 24 hours per day for 70 years. Although such continuous lifetime exposure to maximum Toxic Air Contaminants (TAC) levels is highly unlikely, the goal of the approach is to produce a conservative worst-case estimate of potential cancer risk.

Non-cancer risk is typically reported as a Hazard Index (HI). The HI is calculated for each target organ as a fraction of the maximum acceptable exposure level or REL for an individual pollutant. The REL is generally the level at (or below) which no adverse health effects are expected. The HIs are calculated for both short-term (acute) and long-term (chronic) exposures to non-carcinogenic substances by adding the ratios of predicted concentrations to RELs for all pollutants.

Both cancer and non-cancer risk estimates produced by the HRA represent incremental risks (i.e., risks due to the modeled sources only) and do not include potential health risks posed by existing background concentrations. The HARP model performs all of the necessary calculations to estimate the potential lifetime cancer risk, and the acute and chronic non-cancer HIs due to the Project's TAC emissions. The acute 8-hour HI is calculated directly from the predicted concentrations of acetaldehyde, arsenic, formaldehyde, manganese, and mercury.

9.3.5 HRA Significant Thresholds

A Project-related emissions are considered significant when the predicted increase in lifetime cancer risk exceeds 10 in 1 million (10×10^{-6}) and non-carcinogenic acute and chronic health effects, exposure affects a single target organ, exceed a value of 1.0.

9.3.6 Health Risk Analysis Results

The Estimated Cancer Risk, Acute and Chronic Non-Cancer HI due to HECA operation, including non-permitted sources, presents the results of the HRA at maximally exposed individual resident (MEIR), MEIW, and nearest sensitive receptor.

Table 9-2 HRA Results

Location	Cancer Risk	Chronic Hazard Index	Acute Hazard Index
Off-Site Worker (Tule Elk State Reserve Ranger Station)	2.09 E^{-6}	0.11	0.21
UTM Location	285,106 3,911,707	285,106 3,911,707	285,106 3,911,707
Maximum Impacted Sensitive Receptor	4.28 E^{-6}	0.22	0.31
UTM Location	283,989 3,910,951	283,989 3,910,951	284,401 3,912,477
Maximum Impacted Sensitive Receptor (School)	0.98 E^{-6}	0.06	0.1
UTM Location	285,878 3,908,605	285,878 3,908,605	285,878 3,908,605

The results from the HRA indicate that the impacts from the Project's emissions are below the District Significant Threshold of 10 in 1 million for the .cancer risk and below 1.0 for the acute and chronic hazard indices.

As noted in Table 9-3, all units except unit 26 have a cancer risk below 1 in a million. As required by District Policy any unit that has a cancer risk greater than 1 in a million must implement Toxic Best Available Control Technology (TBACT).

Table 9-3 Risk by Permit Unit

Permit ID#	Model Name	Permitted Risk	TBACT Required
21	GASFUG1	0.00E+00	
21	GASFUG2	0.00E+00	
21	GASFUG3	0.00E+00	
21	SHIFT1	0.00E+00	
21	SHIFT2	0.00E+00	
21	AGRFUG	0.00E+00	
Unit Risk		0.00E+00	N
23	TGTOSTK	4.03E-09	
23	SRUFUG1	0.00E+00	
23	SRUFUG2	0.00E+00	
23	SWSFUG	0.00E+00	
Unit Risk		4.03E-09	N
24	CO2_VENT	8.03E-08	
24	Benz_Fug	6.61E-08	
Unit Risk		1.46E-07	N
25	AUX_BOIL	3.47E-08	
Unit Risk		3.47E-08	N
26	HRSGSTK	1.98E-06	
26	COALDRY	8.57E-07	
Unit Risk		2.84E-06	Y
27	PRCOOL1	8.70E-10	
27	PRCOOL2	8.84E-10	
27	PRCOOL3	8.94E-10	
27	PRCOOL4	9.02E-10	
27	PRCOOL5	9.08E-10	
27	PRCOOL6	9.11E-10	
27	PRCOOL7	9.14E-10	
27	PRCOOL8	9.10E-10	
27	PRCOOL9	8.61E-10	
27	PRCOOL10	7.93E-10	
27	PRCOOL11	8.02E-10	
Unit Risk		9.65E-09	N
28	ASUCOOL1	4.29E-10	
28	ASUCOOL2	4.16E-10	
28	ASUCOOL3	4.28E-10	
28	ASUCOOL4	4.96E-10	
Unit Risk		1.77E-09	N
29	PWCOOL1	5.37E-10	
29	PWCOOL2	5.48E-10	
29	PWCOOL3	5.55E-10	
29	PWCOOL4	5.62E-10	

Permit ID#	Model Name	Permitted Risk	TBACT Required
29	PWCOOL5	5.65E-10	
29	PWCOOL6	5.70E-10	
29	PWCOOL7	5.69E-10	
29	PWCOOL8	5.64E-10	
29	PWCOOL9	5.54E-10	
29	PWCOOL10	5.44E-10	
Unit Risk		5.57E-09	N
30	GF_FLARE	2.32E-09	
Unit Risk		2.32E-09	N
31	SRUFLARE	1.58E-10	
Unit Risk		1.58E-10	N
32	RC_FLARE	6.57E-10	
Unit Risk		6.57E-10	N
33	NH3HEATR	1.91E-09	
Unit Risk		1.91E-09	N
34	UREAPAST	0.00E+00	
34	U_HPABS	0.00E+00	
34	U_LPABS	0.00E+00	
34	UREAFUG1	0.00E+00	
34	UREAFUG2	0.00E+00	
Unit Risk		6.61E-08	N
35	NACID	0.00E+00	
Unit Risk		0.00E+00	N
36	UANFUG	0.00E+00	
36	NH3FUG1	0.00E+00	
36	NH3FUG2	0.00E+00	
Unit Risk		0.00E+00	N
38	EMERGEN1	6.64E-08	
Unit Risk		6.64E-08	N
39	EMERGEN2	4.28E-08	
Unit Risk		4.28E-08	N
40	FWP	4.25E-09	
Unit Risk		4.25E-09	N
Total Risk		3.22E-06	

10 Report Summary

10.1 District Rule 2410 - Prevention of Significant Deterioration (PSD)

District Rule 2410 requires that an Ambient Air Quality Analysis (AAQA) be conducted for the purpose of determining whether a new PSD Major Stationary Source or PSD Major Modification at an existing source will cause or make worse a violation of a National Ambient Air Quality Standard (AAQS). Therefore, the project must demonstrate, using air quality models, the facility's emissions of the regulated air pollutants would not cause or contribute to a violation of:

1) the applicable NAAQS or
2) the applicable PSD increments
3) the applicable AQRV
4) the applicable Visibility
5) the applicable Soil & Vegetation

As previously discussed in the evaluation above, this project is subject to PSD requirements, and the District is required to perform a PSD analysis.

As presented in the Sections 6 & 7 of this document, the proposed project will not cause or contribute significantly to a violation of the National Ambient Air Quality Standard (AAQS), has demonstrated compliance other modeling requirement under District Rule 2410, and no further discussion is required.

10.2 District Rule 2201 - New Source Review (NSR)

Section 4.14 of District Rule 2201 requires that an Ambient Air Quality Analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of a State or National ambient Air Quality Standard (AAQS). An AAQA is required to be performed for all New Source Review (NSR) public notice projects. As previously discussed in the evaluation above, this project requires that a public notice be performed before issuance of the Determination of Compliance. Therefore, the District has reviewed the AAQA for this project.

As presented in Section 8 of this document, the proposed project will not cause or contribute significantly to a violation of the State and National Ambient Air Quality Standard (AAQS) for NOx, CO, PM10, PM2.5, SOx, or other affected pollutant. The impacts from the Projects PM2.5 will be fully offset down to zero and therefore will comply with District Rule 2201 and no further discussion is required.

10.3 Rule 4102 – Nuisance (HRA)

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of this operation, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – ***Risk Management Policy for Permitting New and Modified Sources*** specifies that for an increase in emissions or a change in mode or time of operation associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

The acute and chronic hazard indices were less than 1.0 and the cancer risk associated with the project equals or exceeds one in one million.

BACT for toxic emission control (T-BACT) is required if the cancer risk for a unit equals or exceeds one in one million.

For this project T-BACT is triggered (PM_{10} and VOC) for unit 26. T-BACT is satisfied with BACT for PM_{10} and VOC.

Therefore, in accordance with the District Risk Management Policy, the project is approved with Toxic Best Available Control Technology (T-BACT) requirements and compliance with the District's Risk Management Policy is expected.

Appendix K-A – Rule 2410 Thresholds

District Rule 2410 Thresholds											
Pollutant	**Averaging Period**	**NAAQS (ug/m^3)**	**Comment**	**SMC (ug/m3)**	**SER[a] (Tons/Yr)**	**SILs (ug/m3)**			**Increments (ug/m^3)**		
						Class I	**Class II**	**Class III**	**Class I**	**Class II**	**Class III**
PM2.5	Annual	15[d1]	annual mean, averaged over 3 years		10	0.06	0.3	0.3	1	4	8
	24-Hour	35[d5]	98th percentile, averaged over 3 years	4		0.07	1.2	1.2	2	9	18
PM10	Annual	--			15	0.32	1		4	17[d1]	34
	24-Hour	150[d4]	Not to be exceeded more than once per year on average over 3 years	10		0.2	5		8	30[d2]	60
Carbon Monoxide (CO)	8-Hour	10,000[d2]	Not to be exceeded more than once per year	575	100		500				
	1-Hour	40,000[d2]					2000				
Nitrogen Oxide (NO2)	Annual	100[d1]	Annual Mean	14	40	0.1	1		2.5	25[d1]	50
	1-Hour	188[d5]	98th percentile, averaged over 3 years			--	7.5[e]				
Sulfur Dioxide (SO2)	Annual	80[d1]			40	0.08	1		2	20[d1]	40
	24-Hour	365[d2]		13		0.2	5		5	91[d2]	182
	3-Hour	1300[d2]	Not to be exceeded more than once per year			1	25		25	512[d2]	700
	1-Hour	196[d3]	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years			[f]	7.8[e]				
Ozone (VOC)[b]			Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years		40 (VOCs)		[b]				
Lead	Rolling 3-month average Quarterly		Not to be exceeded	0.1	0.6						
Asbestos					0.007						

District Rule 2410 Thresholds											
Pollutant	**Averaging Period**	**NAAQS (ug/m^3)**	**Comment**	**SMC (ug/m3)**	**SER[a] (Tons/Yr)**	**SILs (ug/m3)**			**Increments (ug/m^3)**		
Fluorides	24-Hour			0.25	3						
Sulfuric Acid Mist					7						
Total Reduced Sulfur Compounds (including H2S)	1-Hour			10	10						
Hydrogen Sulfide	1-Hour			0.2	10						

a) Significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 µg/m3, (24-hour average).

b) a net emissions increase of 100 tons or more per year of VOC is subject to PSD; however, ozone is currently evaluated at a regional level within DAQ and is not further evaluated within the confines of PSD.

c) No Class I SIL available.

d) 1= H1H, 2=H2H, 3=H4H, 4=H6H, 5=H8H

e) Interim SIL

f) Proposed not yet final

Appendix K-B – Class I Areas

Within 100 km of the District Boundaries

Class I Areas
Within 100 Km of the
San Joaquin Valley APCD boundaries

National Wilderness Area

San Gabriel
San Rafael
Domeland
John Muir
Ansel Adams
Kaiser
Hoover
Emigrant
Mokelumne
Desolation
Phillip Burton
Pinnacles
Ventana

National Parks

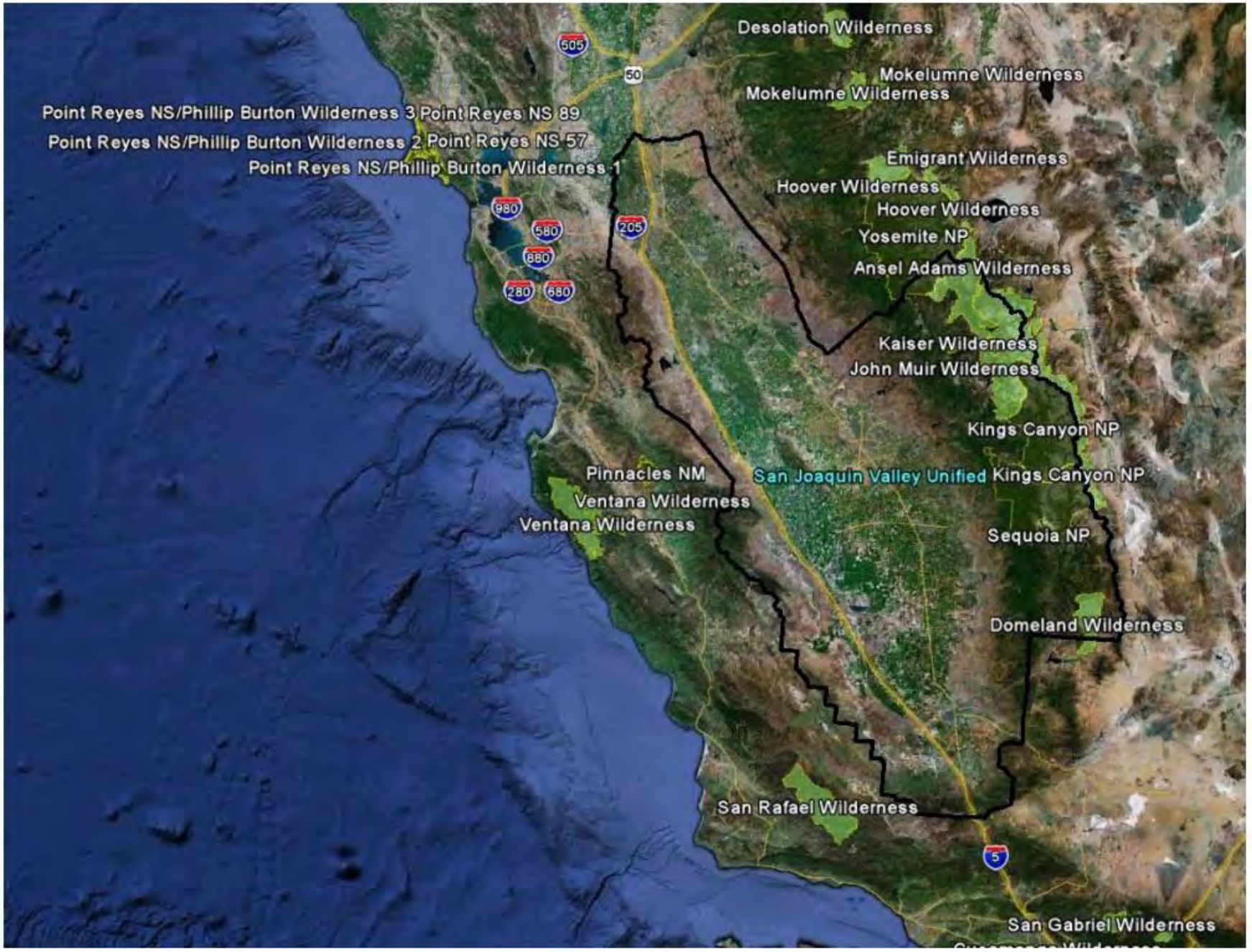
Sequoia
Kings Canyon
Yosemite

National Seashore

Point Reyes

National Monument

Pinnacles


Desolation Wilderness
Mokelumne Wilderness
Mokelumne Wilderness
Point Reyes NS/Phillip Burton Wilderness 3 Point Reyes NS 89
Point Reyes NS/Phillip Burton Wilderness 2 Point Reyes NS 57
Point Reyes NS/Phillip Burton Wilderness 1
Emigrant Wilderness
Hoover Wilderness
Hoover Wilderness
Yosemite NP
Ansel Adams Wilderness
Kaiser Wilderness
John Muir Wilderness
Kings Canyon NP
Pinnacles NM
San Joaquin Valley Unified
Kings Canyon NP
Ventana Wilderness
Ventana Wilderness
Sequoia NP
Domeland Wilderness
San Rafael Wilderness
San Gabriel Wilderness
505
50
980
580
205
880
280
680
5

Appendix K-C – Cumulative Sources

Listing of Nearby Sources

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
1135	115	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	6.13	7.32	421.89	5.51	1.07
1135	119	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	6.13	7.32	421.89	5.51	1.07
1135	122	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	6.13	7.32	421.89	5.51	1.07
1135	123	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	6.13	7.32	421.89	5.51	1.07
1547	144	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	190	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	241	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	243	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	244	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	683	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	684	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	751	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.20	7.32	421.89	5.51	1.07
1547	754	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.20	7.32	421.89	5.51	1.07
1547	761	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.20	7.32	421.89	5.51	1.07
1547	764	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.20	7.32	421.89	5.51	1.07
1547	798	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	799	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	800	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	801	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	805	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	806	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	808	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	812	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	826	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	827	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	828	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	829	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1547	831	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	885	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1547	886	AeraEnergy	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.13	7.32	421.89	5.51	1.07
1135	15	AeraEnergy	Turbine-Small	2.5	MW	NG	0.1032	4.96	13.00	710.22	6.15	1.57
1135	224	AeraEnergy	Turbine-Large	75	MW	NG	0.17	17.66	15.24	367.44	13.03	3.42

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
1135	225	AeraEnergy	Turbine-Large	75	MW	NG	0.17	17.66	15.24	367.44	13.03	3.42
1135	226	AeraEnergy	Turbine-Large	75	MW	NG	0.17	17.66	15.24	367.44	13.03	3.42
1547	148	AeraEnergy	Turbine-Large	21.45	MW	NG	0.17	7.93	15.24	367.44	13.03	3.42
1547	149	AeraEnergy	Turbine-Large	21.45	MW	NG	0.17	2.61	15.24	367.44	13.03	3.42
1547	151	AeraEnergy	Turbine-Large	21.45	MW	NG	0.17	2.59	15.24	367.44	13.03	3.42
1547	459	AeraEnergy	Turbine-Small	4	MW	NG	0.1032	5.93	13.00	710.22	6.15	1.57
1547	879	AeraEnergy	Turbine-Small	3.2	MW	NG	0.1032	2.70	13.00	710.22	6.15	1.57
1547	880	AeraEnergy	Turbine-Small	3.2	MW	NG	0.1032	2.70	13.00	710.22	6.15	1.57
1547	881	AeraEnergy	Turbine-Small	3.2	MW	NG	0.1032	2.70	13.00	710.22	6.15	1.57
1543	33	AeraEnergy	Flare	3,600	MMBtu/hr	NG	0.1	170.04	87.30	1273.00	20.00	10.52
1547	414	AeraEnergy	Flare	60	MMBtu/hr	NG	0.1	7.00	19.68	1273.00	20.00	1.36
1548	134	AeraEnergy	Flare	625	MMBtu/hr	NG	0.1	42.50	33.48	1273.00	20.00	4.38
1548	144	AeraEnergy	Flare	167	MMBtu/hr	vapor	0.1	14.17	23.90	1273.00	20.00	2.27
1548	389	AeraEnergy	Flare	223	MMBtu/hr	NG	0.1	15.17	25.52	1273.00	20.00	2.62
1548	424	AeraEnergy	Flare	825	MMBtu/hr	NG	0.1	56.10	36.39	1273.00	20.00	5.04
1543	5	AeraEnergy	Turbine-Small	13.6	MMBtu/hr	NG	0.17	4.44	13.00	710.22	6.15	1.57
1547	1068	AeraEnergy	IC Engine_Turb	140	BHP	diesel	0.2	3.09	3.00	622.00	53.20	0.08
1547	1069	AeraEnergy	IC Engine_Turb	140	BHP	diesel	0.2	3.09	3.00	622.00	53.20	0.08
1547	1070	AeraEnergy	IC Engine_Turb	140	BHP	diesel	0.2	3.09	3.00	622.00	53.20	0.08
1547	1060	AeraEnergy	Turbine-Small	3.5	MW	NG	0.1032	6.28	13.00	710.22	6.15	1.57
1547	1061	AeraEnergy	Turbine-Small	3.5	MW	NG	0.1032	6.28	13.00	710.22	6.15	1.57
1547	1062	AeraEnergy	Turbine-Small	3.5	MW	NG	0.1032	6.28	13.00	710.22	6.15	1.57
1250	1	BadgerCkLtd	Turbine-Large	48.5	MW	NG	0.17	6.16	15.24	367.44	13.03	3.42
2049	1	BearMtnLtd	Turbine-Large	48	MW	NG	0.17	5.99	15.24	367.44	13.03	3.42
4692	10	Bellanave	IC Engine_Pump	375	BHP	diesel	0.2	5.38	3.00	622.00	76.60	0.13
4692	13	Bellanave	IC Engine_Pump	400	BHP	diesel	0.2	5.73	3.00	622.00	76.60	0.13
4692	14	Bellanave	IC Engine_Pump	400	BHP	diesel	0.2	5.73	3.00	622.00	76.60	0.13
4692	15	Bellanave	IC Engine_Pump	400	BHP	diesel	0.2	5.73	3.00	622.00	76.60	0.13
4692	19	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13
4692	20	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13
4692	21	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13
4692	22	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
4692	23	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13
4692	24	Bellanave	IC Engine_Pump	385	BHP	diesel	0.2	2.28	3.00	622.00	76.60	0.13
1246	19	BerryPetro	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1246	252	BerryPetro	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1246	253	BerryPetro	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1246	254	BerryPetro	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
2265	1	Berry	Turbine-Large	38.7	MW	NG	0.17	8.29	15.24	450.78	13.03	3.42
1246	255	BerryPetro	Flare		MMBtu/hr	Vapor	0.1	2.03	18.80	1273.00	20.00	1.17
4751	7	BidartDairy	IC Engine_Pump	360	BHP	Diesel	0.2	5.16	3.00	622.00	76.60	0.13
4751	9	BidartDairy	IC Engine_Pump	200	BHP	Diesel	0.2	2.87	3.00	622.00	59.90	0.10
33	402	BigWest	IC Engine_Comp	450	HP	Diesel	0.2	6.85	3.00	622.00	66.50	0.15
33	17	BigWest	Boiler/Steam Gen	92	MMBtu/hr	NG	0.32	2.85	20.00	373.00	10.00	0.61
33	348	BigWest	Boiler/Steam Gen	200	MMBtu/hr	NG	0.32	2.20	20.00	373.00	10.00	0.91
33	59	BigWest	Boiler/Steam Gen	42	MMBtu/hr	NG	0.32	5.48	20.00	373.00	10.00	0.30
33	61	BigWest	Boiler/Steam Gen	78.8	MMBtu/hr	NG	0.32	10.25	20.00	373.00	10.00	0.61
34	42	BigWest	Boiler/Steam Gen	98	MMBtu/hr	NG	0.32	3.53	20.00	373.00	10.00	0.61
33	11	BigWest	Process Heaters_Dryers	12.8	MMBtu/hr	NG	0.32	4.61	20.00	366.33	10.00	1.22
33	12	BigWest	Process Heaters_Dryers		MMBtu/hr	Vapor	0.32	19.22	20.00	366.33	10.00	1.22
33	13	BigWest	Process Heaters_Dryers		MMBtu/hr	NG	0.32	6.72	20.00	366.33	10.00	1.22
33	338	BigWest	Process Heaters_Dryers		MMBtu/hr	NG	0.32	3.50	20.00	366.33	10.00	1.22
33	49	BigWest	Process Heaters_Dryers	161.4	MMBtu/hr	NG	0.32	4.01	20.00	366.33	10.00	1.22
33	52	BigWest	Process Heaters_Dryers	86.8	MMBtu/hr	NG	0.32	15.62	20.00	366.33	10.00	1.22
33	53	BigWest	Process Heaters_Dryers	65	MMBtu/hr	NG	0.32	8.87	20.00	366.33	10.00	1.22
33	55	BigWest	Process Heaters_Dryers	233	MMBtu/hr	NG	0.32	2.56	20.00	366.33	10.00	1.22

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
33	56	BigWest	Process Heaters_Dryers		MMBtu/hr	NG	0.32	21.73	20.00	366.33	10.00	1.22
33	8	BigWest	Process Heaters_Dryers	209	MMBtu/hr	NG	0.32	4.64	20.00	366.33	10.00	1.22
33	9	BigWest	Process Heaters_Dryers	142.6	MMBtu/hr	NG	0.32	5.13	20.00	366.33	10.00	1.22
34	1	BigWest	Process Heaters_Dryers	96	MMBtu/hr	NG	0.32	3.45	20.00	366.33	10.00	1.22
34	2	BigWest	Process Heaters_Dryers	38.3	MMBtu/hr	NG	0.32	6.90	20.00	366.33	10.00	1.22
34	3	BigWest	Process Heaters_Dryers	35	MMBtu/hr (TWO)	NG	0.32	12.60	20.00	366.33	10.00	1.22
3984	2	BowmanAsphalt	Process Heaters_Dryers		MMBtu/hr	NG	0.1	6.50	10.00	310.78	10.00	0.46
40	3	CentralRes	Flare		MMBtu/hr	NG	0.1	18.72	17.57	1273.00	20.00	0.45
723	1	ChalkCliffLtd	Turbine-Large	49	MW	NG	0.17	7.95	15.24	450.78	13.03	3.42
1129	47	Chevron	Turbine-Small	3.5	MW	NG	0.1032	7.60	13.00	710.22	6.15	1.57
1129	48	Chevron	Turbine-Small	3.5	MW	NG	0.1032	7.60	13.00	710.22	6.15	1.57
1129	49	Chevron	Turbine-Small	3.5	MW	NG	0.1032	7.60	13.00	710.22	6.15	1.57
1129	53	Chevron	Turbine-Small	3.5	MW	NG	0.1032	6.38	13.00	710.22	6.15	1.57
1129	54	Chevron	Turbine-Small	3.5	MW	NG	0.1032	6.38	13.00	710.22	6.15	1.57
3317	1	Chevron	IC Engine_Comp	1200	HP	NG	0.6	2.08	6.40	691.33	9.66	0.51
3317	2	Chevron	IC Engine_Comp	1200	HP	NG	0.6	2.08	6.40	691.33	9.66	0.51
1127	22	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	29	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	30	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	31	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	34	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	35	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	36	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	70	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	16	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	18	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	19	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
1128	21	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	25	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	26	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	28	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	29	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	30	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	31	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	32	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	33	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	34	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	36	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	38	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	48	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	57	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	58	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	75	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	77	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	159	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1128	941	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	62	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	63	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	64	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	66	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	67	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	68	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	69	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	70	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	73	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	78	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	82	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	95	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	98	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
1131	99	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	859	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	879	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	881	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	883	Chevron	Boiler/Steam Gen	62.5	MM	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	884	Chevron	Boiler/Steam Gen	62.5	MM	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	908	Chevron	Boiler/Steam Gen	62.5	MM	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	912	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	987	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	997	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1131	999	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	19	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	26	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	31	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	38	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	43	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	44	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	45	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	51	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	67	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	368	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	369	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	370	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	371	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	372	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	373	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	374	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	380	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	402	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	516	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	549	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	550	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
1141	551	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	552	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	553	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	554	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	555	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	556	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	557	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1141	558	Chevron	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1127	148	Chevron	Turbine-Large	22.3	MW	NG	0.17	5.58	15.24	450.78	13.03	3.42
1127	149	Chevron	Turbine-Large	22.3	MW	NG	0.17	5.58	15.24	450.78	13.03	3.42
1128	366	Small turbine	Turbine-Small	2.7	MW	NG	0.1032	10.45	13.00	367.44	6.15	1.57
1128	367	Chevron	Turbine-Small	2.7	MW	NG	0.1032	10.45	13.00	367.44	6.15	1.57
1128	368	Chevron	Turbine-Small	2.7	MW	NG	0.1032	10.45	13.00	367.44	6.15	1.57
1128	369	Chevron	Turbine-Small	2.7	MW	NG	0.1032	10.45	13.00	367.44	6.15	1.57
1128	370	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.58	13.00	367.44	6.15	1.57
1128	371	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.58	13.00	367.44	6.15	1.57
1128	372	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1128	373	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1128	374	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1128	375	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1128	376	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1128	377	Chevron	Turbine-Small	2.7	MW	NG	0.1032	11.59	13.00	367.44	6.15	1.57
1131	970	Chevron	Turbine-Small	3.725	MW	NG	0.1032	6.76	13.00	367.44	6.15	1.57
1131	973	Chevron	Turbine-Small	3.725	MW	NG	0.1032	6.76	13.00	367.44	6.15	1.57
1131	974	Chevron	Turbine-Small	3.725	MW	NG	0.1032	6.71	13.00	367.44	6.15	1.57
1131	1037	Chevron	Turbine-Large	20	MW	NG	0.17	4.58	15.24	710.22	13.03	3.42
1131	1038	Chevron	Turbine-Small	58.2	MMBtu/hr,	NG	0.1032	7.51	15.24	367.44	13.00	3.42
1131	1039	Chevron	Turbine-Small	58.2	MMBtu/hr,	NG	0.1032	7.51	15.24	367.44	13.00	3.42
1131	1079	Chevron	Turbine-Small	4.1	MW	NG	0.1032	4.48	13.00	367.44	6.15	1.57
1128	116	Chevron	Flare	167	MMBtu/hr	vapor	0.1	19.98	23.90	1273.00	20.00	2.27
1141	513	Chevron	Flare	167	MMBtu/hr	Vapor	0.1	16.68	23.90	1273.00	20.00	2.27
1141	514	Chevron	Flare	167	MMBtu/hr	Vapor	0.1	16.68	23.90	1273.00	20.00	2.27

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
75	11	CovDelanoInc	Fluidized bed-bio	315	MMBtu/hr	biomass	0.5	31.50	30.48	383.00	25.00	2.00
75	6	CovDelanoInc	Fluidized bed-bio	400	MMBtu/hr	biomass	0.5	40.00	30.48	383.00	25.00	2.00
724	1	DAIOildaleInc	Turbine-Large	22.1	MW	NG	0.17	7.11	15.24	367.44	13.03	3.42
1119	1	DblCLtd	Turbine-Large	25	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
1119	2	DblCLtd	Turbine-Large	25	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
3523	1	Elk	Turbine-Large	250.5	MMBtu/hr	NG	0.17	38.00	36.60	345.00	12.50	5.49
3523	2	Elk	Turbine-Large	250.5	MMBtu/hr	NG	0.17	38.00	36.60	345.00	12.50	5.49
1328	1	ExxonMobil	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1328	2	ExxonMobil	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
1328	3	ExxonMobil	Boiler/Steam Gen	62.5	MMBtu/hr	NG	0.1	2.25	7.32	421.89	5.51	1.07
705	1	FarmersCoopGin	Process Heaters_Dryers		MMBtu/hr	NG	0.32	2.02	12.19	310.78	23.00	0.46
2076	9	Frito	Turbine-Small	6	MW	NG	0.1032	12.48	9.75	367.44	6.15	1.57
2076	17	Frito	Oven	9.56	MMBtu/hr	NG	0.32	2.35	9.75	427.44	0.07	0.66
2076	18	Frito	Oven	20	MMBtu/hr	NG	0.32	3.40	9.75	427.44	0.07	0.66
1118	1	HiSierraLtd	Turbine-Large	24	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
1118	2	HiSierraLtd	Turbine-Large	24	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
1120	1	KernFrontLtd	Turbine-Large	25	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
1120	2	KernFrontLtd	Turbine-Large	25	MW	NG	0.17	4.04	15.24	450.78	13.03	3.42
1678	1	KernMedCtr	Boiler/Steam Gen	16.8	MMBtu/hr	NG	0.1	2.45	10.00	373.00	10.00	0.30
37	114	KernOil&RefCo	Turbine-Small	4.968	MW	NG	0.1032	3.51	13.00	367.44	6.15	1.57
37	1	KernOil&RefCo	Process Heaters_Dryers	120	MMBtu/hr	NG	0.32	4.32	20.00	366.33	10.00	1.22
88	1	KernRvrCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
88	2	KernRvrCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
88	3	KernRvrCogen	Turbine-Large	75	MW	NG	0.17	23.03	15.24	367.44	13.03	3.42
88	4	KernRvrCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
3412	1	LaPalomaGen	Turbine-Large	262	MW	NG	0.17	21.31	36.60	345.00	12.50	5.49
3412	2	LaPalomaGen	Turbine-Large	262	MW	NG	0.17	21.31	36.60	345.00	12.50	5.49
3412	3	LaPalomaGen	Turbine-Large	262	MW	NG	0.17	21.31	36.60	345.00	12.50	5.49
3412	4	LaPalomaGen	Turbine-Large	262	MW	NG	0.17	21.31	36.60	345.00	12.50	5.49

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
172	1	LiveOakLtd	Turbine-Large	48	MW	NG	0.17	5.78	15.24	367.44	13.03	3.42
1251	1	McKittrickLtd	Turbine-Large	48	MW	NG	0.17	6.16	15.24	367.44	13.03	3.42
2592	1	Mid-SetCogen	Turbine-Large	39.86	MW	NG	0.17	18.26	15.24	450.78	13.03	3.42
91	3	MtPosoCogen	Fluidized bed-other	49.9	MW	multi-fuel	0.5	58.60	15.24	450.78	13.03	3.42
3340	1	LostHillsPetro	Flare		MMBtu/hr	NG	0.1	16.53	30.27	1273.00	20.00	3.67
5141	5	OasisDairy	IC Engine_Pump	275	BHP	Diesel	0.2	2.15	3.00	622.00	57.50	0.13
1216	87	Oxy	Flare	44.58	MMBtu/hr		0.1	3.03	18.79	1273.00	20.00	1.17
1216	88	Oxy	Flare	44.58	MMBtu/hr		0.1	3.03	18.79	1273.00	20.00	1.17
2234	52	Large turbine	Turbine-Large	25	HP	NG	0.17	4.11	30.48	477.59	41.17	2.29
2234	53	Oxy	Turbine-Large	25	HP	NG	0.17	4.11	30.48	477.59	41.17	2.29
382	675	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	676	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	422	Oxy	IC Engine	310	HP	Diesel	0.2	3.10	3.00	622.00	57.41	0.13
2234	44	Oxy	IC Engine	773	HP	NG	0.1	3.41	6.40	638.15	6.45	0.51
2234	46	Oxy	IC Engine	793	HP	NG	0.1	3.50	6.40	638.15	6.45	0.51
2234	87	Oxy	IC Engine_Comp	88	HP	NG	0.6	2.11	6.40	638.15	6.45	0.51
382	677	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	678	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	679	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	680	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
382	681	Oxy	Heater	12	MMBtu/hr	NG	0.32	0.43	6.40	422.04	13.17	0.46
2234	10	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
2234	11	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
2234	12	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	655.37	8.49	0.91
2234	123	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	124	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	127	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	128	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	129	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	130	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
2234	131	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	132	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	133	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	134	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	135	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	136	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	15	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
2234	16	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
2234	17	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
2234	18	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	655.37	8.49	0.91
2234	182	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	183	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	184	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	185	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	186	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	187	Oxy	IC Engine_Comp	1680	HP	NG	0.6	0.26	6.40	644.26	23.54	0.51
2234	188	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	189	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	190	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	191	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	192	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	193	Oxy	IC Engine_Comp	1834	HP	NG	0.6	0.28	6.40	644.26	23.54	0.51
2234	27	Oxy	IC Engine_Comp	4000	HP	NG	0.6	14.55	12.19	649.26	17.15	0.91
2234	28	Oxy	IC Engine_Comp	4000	HP	NG	0.6	14.55	12.19	649.26	17.15	0.91
2234	29	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	691.48	9.66	0.51
2234	30	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	691.48	9.66	0.51
2234	31	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	691.48	9.66	0.51
382	32	Oxy	IC Engine_Comp	4000	HP	NG	0.6	14.55	12.19	649.26	19.33	0.91
382	62	Oxy	IC Engine_Comp	4000	HP	NG	0.6	14.55	12.19	649.26	19.33	0.91
382	63	Oxy	IC Engine_Comp	4000	HP	NG	0.6	14.55	12.19	649.26	19.33	0.91
2234	48	Oxy	IC Engine_Comp	490	HP	NG	0.6	0.78	4.57	644.26	14.56	0.30
2234	57	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
2234	58	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	59	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	60	Oxy	IC Engine_Comp	650	HP	NG	0.6	1.03	6.40	638.15	6.45	0.51
2234	61	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	62	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	655.37	8.49	0.91
2234	63	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	64	Oxy	IC Engine_Comp	650	HP	NG	0.6	1.03	6.40	644.26	6.45	0.51
2234	65	Oxy	IC Engine_Comp	650	HP	NG	0.6	1.03	6.40	644.26	6.45	0.51
2234	66	Oxy	IC Engine_Comp	650	HP	NG	0.6	1.03	6.40	644.26	6.45	0.51
2234	67	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
382	670	Oxy	IC Engine_Comp	1000	HP	NG	0.6	3.31	6.40	644.26	9.66	0.51
382	671	Oxy	IC Engine_Comp	1000	HP	NG	0.6	3.31	6.40	644.26	9.66	0.51
382	672	Oxy	IC Engine_Comp	1000	HP	NG	0.6	3.31	6.40	644.26	9.66	0.51
2234	68	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	69	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	70	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	71	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	72	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	73	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	74	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	75	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	644.26	8.49	0.91
2234	76	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	644.26	8.49	0.91
2234	77	Oxy	IC Engine_Comp	2000	HP	NG	0.6	7.72	12.19	644.26	8.49	0.91
2234	78	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	79	Oxy	IC Engine_Comp	1000	HP	NG	0.6	1.59	6.40	644.26	9.66	0.51
2234	80	Oxy	IC Engine_Comp	1000	HP	NG	0.6	3.97	6.40	644.26	9.66	0.51
2234	81	Oxy	IC Engine_Comp	1000	HP	NG	0.6	3.97	6.40	644.26	9.66	0.51
2234	82	Oxy	IC Engine_Comp	1500	HP	NG	0.6	5.95	6.40	644.26	16.16	0.51
2234	83	Oxy	IC Engine_Comp	1500	HP	NG	0.6	5.95	6.40	644.26	16.16	0.51
2234	84	Oxy	IC Engine_Comp	490	HP	NG	0.6	0.78	4.57	644.26	14.56	0.30
2234	85	Oxy	IC Engine_Comp	490	HP	NG	0.6	0.78	4.57	644.26	14.56	0.30
2234	86	Oxy	IC Engine_Comp	490	HP	NG	0.6	0.78	4.57	644.26	14.56	0.30

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
2234	9	Oxy	IC Engine_Comp	5500	HP	NG	0.6	20.01	12.19	657.59	23.73	0.91
73	2	OildaleEnergy	Turbine-Large	43	MW	NG	0.17	38.77	15.24	367.44	13.03	3.42
2896	2	PacifiProcSys	Flare	83.3	MMBtu/hr (SIX)	NG	0.1	8.50	20.82	1273.00	20.00	1.60
2896	7	PacifiProcSys	Flare	10	MMscf/day	NG	0.1	28.33	30.27	1273.00	20.00	3.67
892	4	PactivCorp	Process Heaters_Dryers		MMBtu/hr	NG	0.32	2.24	13.00	310.78	10.00	0.46
377	19	ParamtFarms	Process Heaters_Dryers	550.5	MMBtu/hr	NG	0.1	42.43	13.00	310.78	10.00	0.46
377	20	ParamtFarms	Process Heaters_Dryers	23.33	MMBtu/hr	NG	0.32	5.20	13.00	310.78	10.00	0.46
377	21	ParamtFarms	Process Heaters_Dryers	3	MMBtu/hr	NG	0.32	13.18	13.00	310.78	10.00	0.46
377	3	ParamtFarms	Process Heaters_Dryers	396	MMBtu/hr	NG	0.1	32.95	13.00	310.78	10.00	0.46
377	47	ParamtFarms	Process Heaters_Dryers	13.4	MMBtu/hr	NG	0.32	0.76	13.00	310.78	10.00	0.46
713	1	ParamtFarms	Process Heaters_Dryers	27	MMBtu/hr	NG	0.32	36.31	13.00	310.78	10.00	0.46
287	1	PetroProdTest	Flare	41.5	MMBtu/hr	Propane	0.1	5.83	18.60	1273.00	20.00	1.13
1372	26	Plains	Boiler/Steam Gen	32	MMBtu/hr	NG	0.1	5.12	7.32	421.89	5.51	1.07
1372	77	Plains	Boiler/Steam Gen	33.3	MMBtu/hr	Vapor	0.1	2.27	7.32	421.89	5.51	1.07
1372	187	Plains	Turbine-Small	3.27	MW	NG	0.1032	9.58	13.00	367.44	6.15	1.57
1372	188	Plains	Turbine-Small	3.27	MW	NG	0.1032	9.58	13.00	367.44	6.15	1.57
1372	194	Plains	Turbine-Small	4.72	MW	NG	0.1032	7.21	13.00	367.44	6.15	1.57
71	14	Plains	Process Heaters_Dryers	105	MMBtu/hr	NG	0.32	3.15	12.19	310.78	2.78	1.82
71	4	Plains	Process Heaters_Dryers	80	MMBtu/hr	NG	0.32	2.40	12.19	310.78	2.56	1.89
1751	3	RioBravoJasmin	Solid Fuel combustor	36	MW	solid fuel	0.5	77.82	30.48	383.00	25.00	2.00
883	3	RioBravoPoso	Solid Fuel combustor	36	MW	solid fuel	0.5	77.82	30.48	383.00	25.00	2.00
36	99	SanJoaquinRefin	Boiler/Steam Gen	12.6	MMBtu/hr	NG	0.1	5.77	20.00	373.00	10.00	0.30

Facility ID	Permit Number	Short Facility Name	Short Equip Description	Eqp Rating	Rating Units	Fuel	In-stack Ratio (NO2/NOx)	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)
36	51	SanJoaquinRefin	Flare	103.4	MMBtu/hr	NG	0.1	3.45	21.67	1273.00	20.00	1.78
36	1	SanJoaquinRefin	Process Heaters_Dryers	79.2	MMBtu/hr	NG	0.32	5.80	20.00	366.33	10.00	1.22
3746	1	Sunrise	Turbine-Large	160	MW	NG	0.17	48.79	36.60	345.00	12.50	5.49
3746	2	Sunrise	Turbine-Large	160	MW	NG	0.17	48.79	36.60	345.00	12.50	5.49
511	1	SycamoreCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
511	2	SycamoreCogen	Turbine-Large	75	MW	NG	0.17	23.03	15.24	450.78	13.03	3.42
511	3	SycamoreCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
511	4	SycamoreCogen	Turbine-Large	75	MW	NG	0.17	67.90	15.24	450.78	13.03	3.42
44	5	TricorRef	Boiler/Steam Gen	99.9	MMBtu/hr	NG	0.1	3.10	13.00	373.00	10.00	0.61
44	1	TricorRef	Process Heaters_Dryers	61	MMBtu/hr	NG	0.32	0.60	13.00	310.78	10.00	0.46
44	145	TricorRef	Process Heaters_Dryers	64.3	MMBtu/hr	NG	0.32	3.21	13.00	310.78	10.00	0.46
44	2	TricorRef	Process Heaters_Dryers	40	MMBtu/hr	NG	0.32	5.84	13.00	310.78	10.00	0.46
1737	157	Vintage	Flare	41.7	MMBtu/hr	Vapor	0.1	8.67	18.61	1273.00	20.00	1.13
1737	168	Vintage	Process Heaters_Dryers	5	MMBtu/hr (TWO)	Vapor	0.32	2.26	13.00	310.78	10.00	0.46
4294	1	WorldOil	Process Heaters_Dryers	4	MMBtu	NG	0.32	12.88	7.62	394.11	10.00	0.46

APPENDIX L
Mitigation Agreements

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

GOVERNING BOARD

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Seyed Sadredin
Executive Director
Air Pollution Control Officer

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34946 Flyover Court
Bakersfield, CA 93308-9725
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www.valleyair.org

DATE: April 18, 2013

TO: SJVUAPCD Governing Board

FROM: Seyed Sadredin, Executive Director/APCO
Project Coordinator: Dave Warner

RE: **ITEM NUMBER 9: APPROVE TWO MITIGATION AGREEMENTS WITH HYDROGEN ENERGY CALIFORNIA, LLC. TO RECEIVE FUNDS IN THE AMOUNT OF APPROXIMATELY $8,747,160 FOR THE PURPOSE OF MITIGATING AIR QUALITY IMPACTS OF A PROPOSED NEW POWER GENERATION FACILITY IN KERN COUNTY**

RECOMMENDATION:

1. Approve and authorize the Chair to sign the attached agreement number 20130092 with Hydrogen Energy California, LLC, in the amount of approximately $7,566,025 to fund emission reduction projects to mitigate construction emissions and indirect emissions from plant operations.

2. Approve and authorize the Chair to sign the attached agreement number 20130026 with Hydrogen Energy California, LLC, in the amount of approximately $1,181,135 to fund emission reduction projects to mitigate stationary source emissions.

3. Authorize staff to identify, fund and manage emission reduction projects that will mitigate the project's emissions in accordance with the attached agreements.

BACKGROUND:

Hydrogen Energy California LLC (HECA) is proposing to build and operate a 300 megawatt (MW) base load power plant and associated fertilizer manufacturing facility 2 miles northwest of the unincorporated community of Tupman in Kern County. The permitting authority for this project rests with the California Energy

Commission (CEC). The CEC is the sole licensing authority in California for power plants of greater than 50 MW of power output. Other land-use and permitting agencies in the state, including the Air District, are relegated to a commenting and advisory role in such cases. However the District has evaluated the project for compliance with all applicable air quality regulations.

The District's analysis shows compliance with all applicable air quality rules and regulations. However, in light of the Valley's unique challenges in meeting the federal standards, District staff raised concerns regarding HECA's emissions and expressed a need for full mitigation of all significant emissions. HECA agreed, and today's recommendations will provide the path for HECA to provide such mitigation through an enforceable, verifiable and proven emission reduction generating process through the District's emission reduction incentive grant program.

Since 2005, the District has entered into Voluntary Emission Reduction Agreements (VERA) with developers to mitigate the air impacts of their development projects. These agreements benefit air quality by achieving additional reductions in emissions. The District has entered into 18 VERAs, and to date has received $12,434,671.78 in revenues. Currently, projects funded by the District achieved total emission reductions of 1,089.20 tons of NOx, 128.31 tons of VOC, and 37.10 tons of PM10. The agreements before you today are similar to the previous agreements approved by your Board.

DISCUSSION:

This proposed HECA facility utilizes an integrated gasification system that will gasify coal, petroleum coke, or blends of petroleum coke and coal, to produce hydrogen to fuel a combustion turbine operating in combined cycle mode to produce a nominal 405 gross megawatts. The net nominal output to the grid will be 300 megawatts of base load power. The project will also capture approximately 90 percent of the carbon from the raw synthesis gas, which will be transported via pipeline to a neighboring oil field for enhanced oil recovery and carbon sequestration. The facility will also manufacture nitrogen based fertilizer products. On-site construction of the project is expected to take place from late-2013 to mid-2017. Commercial operation is planned by mid-2017. The proposed power plant will be located on a 453-acre parcel in western Kern County, approximately 7 miles west of the outermost edge of the City of Bakersfield and 2 miles northwest of the unincorporated community of Tupman.

The facility also will be equipped with the best air pollution control equipment that is available for this type of facility. Between the integrated gasification, the CO2 sequestration, and the air pollution control equipment, the HECA facility is the cleanest coal power plant proposal that the District is aware of. The remaining emissions from the stationary sources of emissions, after employing these controls, must be mitigated

under District rules regulating new and modified sources, through the purchase of emissions reduction credits from other businesses that have voluntarily reduced emissions.

The District has also analyzed the potential impacts of the HECA proposal on ambient air quality, through very conservative computer modeling techniques approved by the state and federal governments for such analyses, and has found no expected violations of ambient air quality standards. In addition, the District has performed additional computer modeling to analyze the maximum potential health risk from air toxics generated by the facility. The District's analysis found that air toxics from the HECA facility will not pose a significant risk to anyone.

For projects under CEC's jurisdiction, District rules require that we prepare an official commenting document, called a Determination of Compliance (DOC), with which the District provides an analysis of the power plant's ability to comply with all applicable air quality regulations and provides detailed descriptions of conditions of approval that the District believes are necessary for the CEC to use in its licensing decision.

The District has issued a preliminary DOC, and has requested comments from the public, the state Air Resources Board, the federal Environmental Protection Agency, the California Energy Commission, and other interested parties. The District's Executive Director testified to the Kern County Board of Supervisors on the District's findings on February 26, 2013. In addition, District staff held a public hearing on April 2, 2013, at the District office in Bakersfield, at which verbal public comments were accepted. The District will also be holding a second public hearing on May 15, at 6:00 PM, at Buttonwillow School, focusing on inviting comment from Spanish speaking residents. The comment period is scheduled to end on May 30, 2013 to provide attendees of the second public hearing sufficient time to submit comments. District staff will respond to all comments received prior to making a final decision on its Determination of Compliance.

In summary, the District's analysis of HECA's proposal concludes that HECA will comply with all applicable air quality regulations if the CEC implements the conditions of approval as recommended by the District.

Additional Emissions Being Mitigated:

The direct and indirect emissions from and associated with this facility will be mitigated through the use of Emission Reduction Credits (ERCs) and with the execution of the emission reduction agreements before your Board today. The following emissions are being mitigated:

1. Emissions from the stationary sources
2. Emissions caused by efficiency losses due to coal gasification and CO2 sequestration processes
3. All emissions from construction
4. Mobile source emissions associated with fuel delivery, fertilizer shipment and waste removal

HECA provided ERCs in the amounts of 451 tons per year of NOx, VOC, SOx and PM10 to mitigate on site emissions increases. This represents a ratio of 1.4 pounds of reductions for every pound of increased emissions being proposed. Furthermore, the facility's potential emissions were used in calculating the quantity of required mitigation. This will provide extra mitigation because the facility's actual emissions will be much lower.

Additionally, the District has expressed concern that the plant will emit about 17 tons per year higher NOx emissions than a new natural gas fired base load power plant with a similar power output to the grid, due to the efficiency losses discussed above. HECA has also agreed to provide funding for additional mitigation of NOx emissions for stationary source operational emissions, above and beyond the mitigation required by District regulations. This will provide double mitigation for a portion of the facility's emissions.

In addition to the mitigation of stationary source emissions required under the District's regulations described above, the construction and operation of the HECA facility would generate significant additional emissions that are generally beyond the scope of the District's regulatory authority.

Approximately 350 tons of NOx, VOC and PM10 emissions are expected during the four years of construction of the facility, and HECA has agreed to fully mitigate these emissions. In addition, there will be as much as 44 tons per year of NOx emissions generated in the San Joaquin Valley by mobile sources associated with the operation of HECA, bringing fuel and other supplies to the facility, and removing waste materials and fertilizer products. HECA is planning two potential scenarios for deliveries and shipment; one in which some materials are moved by train and some by truck, and one in which all materials are moved by truck. HECA has agreed to mitigate the emissions based on the worst-case conditions, represented by the all-truck scenario. While the mitigation agreement will assist HECA in demonstrating compliance with requirements under federal General Conformity and the state California Environmental Quality Act (CEQA), as discussed more fully below, HECA has voluntarily agreed to go beyond these rules and fully mitigate all of the significant pollutants from these sources.

Key Issues and Concerns Regarding this Project:

1. Can the District deny a permit to HECA?

   The District is not the permitting authority under state law for power plants of more than 50 MW in power output. As noted above, in California, only the CEC has a licensing role or authority for such projects, and is therefore the only agency that can deny such requests for a license. Even in situations where the District does have direct permitting authority (as is the case with virtually any kind of stationary source of emissions other than large power plants), the District can only issue or deny permits on the basis of a proposal's compliance with air quality requirements. If a proposal complies with all air quality regulations, we are required to issue a permit. District actions to execute mitigation agreements (today's recommendations) or any issuance of a Determination of Compliance do not constitute an approval or permit to initiate construction.

2. How will the District handle emissions increases from other facilities associated with the HECA proposal?

   Any facility that will experience increases in emissions above their currently allowable emissions will be required to obtain permits from the District before implementing the changes. These facilities will be subject to Best Available Control Technology requirements and mitigation of any significant emissions increases. CEC's approval of HECA's proposal does not automatically confer to other facilities a permit or right to expand their operations.

3. Has the District analyzed the potential for HECA to create health impacts?

   The District's analysis considered all operations of the facility and found that HECA can and is expected to operate in a way that does not generate any significant health impacts, and has provided to the CEC appropriate recommendations regarding specific conditions of approval that, if adopted by the CEC, will assure the same. In making these determinations, the District uses complex computer modeling, and follows guidelines established by the state's Office of Environmental Health and Hazard Assessment (OEHHA). OEHHA is the expert in this field, and their guidelines are seen as setting the standard for how to do risk assessments.

   These processes are extremely conservative in nature. We use conservative assumptions throughout the process in establishing the potential risk of individual compounds, in setting standards for what meteorological data to use, and at essentially every decision point the assumption chosen will be that which maximizes, not minimizes, the calculated risk. Just as an example of the

conservative nature of these assumptions, long term risks are calculated as if a person was sitting at the point of worst-case concentration for 70 years.

4. Do District offsetting requirements truly mitigate stationary source emissions when some ERCs used were banked 30 years ago?

   ERCs are recognized by all air districts in California, the state Air Resources Board, and federal EPA as real mitigation for emissions increases when appropriate safeguards are employed. The following safeguards are in place in the San Joaquin Valley to assure that the use of ERCs will provide real benefit to air quality:
   - Credits are issued for actual emissions reductions that go beyond that which is required by law, with no credit available for reducing permitted emissions,
   - Reductions are discounted for any requirements that currently apply
   - Reductions are discounted for any anticipated future requirements,
   - Ten percent of the reductions are confiscated and retired permanently,
   - The ERCs are incorporated in the Region's growth factors as emissions in the air in attainment plans and associated emissions inventories. The attainment plans then provide for real-time mitigation to ensure contemporaneous air quality benefit, regardless of the date the credits were banked.
   - Comprehensive annual accounting and reporting to document and verify real-time benefit to air quality.

5. Does the District have the authority to require mitigation of construction and mobile source emissions associated with stationary sources?

   Except for sources subject to the Indirect Source Review Rule, the answer is no. However, upon your Board's approval of the attached agreements, HECA will be required to provide funding to implement emissions reduction projects that will completely mitigate construction emissions and all NOx emissions from mobile sources associated with the ongoing operations of the facility.

<u>Details of the Agreements</u>:

Due to the receipt of significant federal funds in the form of a grant from the United States Department of Energy (DOE), the HECA project is subject to the requirements of the Federal Clean Air Act General Conformity Rule (Title 40, Code of Federal Regulations, Part 93, Subpart B), which requires mitigation of mobile source and other indirect emissions associated with the project, to the extent that such emissions are not captured in the State Implementation Plan. As a result, Hydrogen Energy California, LLC prepared and submitted a General Conformity Evaluation (March 2013) which

includes an assessment of the Project construction and operational air quality emission impacts to determine if emissions would exceed any of the San Joaquin Valley Air Basin General Conformity Thresholds and subsequently determine if the project would conform to the District's State Implementation Plan (SIP).

The evaluation concluded project construction and operational indirect emissions are expected to exceed the following Conformity Thresholds in the San Joaquin Valley Air Basin: 10 tons/year of oxides of nitrogen (NOx), and 10 tons/year of volatile organic compounds (VOC), and concluded that these emissions are not included in the current SIP. The District concurred with these conclusions. As previously discussed, HECA agreed to fully mitigate with contemporaneous emissions reductions all construction and operation emission increases for any pollutant for which significant impacts to air quality would otherwise be expected.

In addition, the evaluation concluded indirect emissions are expected to exceed the District's thresholds for determining significance under the California Environmental Quality Act (CEQA) of 10 tons/year of NOx, 10 tons/year of VOC and 15 tons/year of particulate matter of 10-microns in size and smaller (PM10).

To satisfy General Conformity Rule and CEQA requirements, Hydrogen Energy California has entered into a Mitigation Agreement with the District to mitigate the project's indirect emissions. For construction emission impacts, the MA requires indirect emissions of any criteria pollutant exceeding the applicable General Conformity Threshold or CEQA Significance Threshold in any given year to be fully offset and mitigated for that pollutant for the entire project construction period, resulting in mitigation of all NOx, VOC, and PM10 construction emissions. For operational emission impacts, all indirect emissions of NOx, the only criteria pollutant exceeding the applicable General Conformity Threshold or CEQA Significance Threshold, will be fully offset and mitigated for that pollutant.

The District has concluded that the MA is appropriately designed to satisfy federal General Conformity and state CEQA requirements. As a result, 287.2 tons NOx emissions, 61.3 tons PM10 emissions and 39.5 tons VOC emissions are to be mitigated within the Valley. The mitigation fee for NOx and VOC are $9,350 per ton, and $9,011 per ton for PM10 which are based on the per ton cost schedule for compliance with District Rule 9510 (Indirect Source Review), plus a 4% administrative cost associated with the District for implementing a grant program to bring in the intended NOx, VOC and PM10 reductions. At these rates, the sum of $7,566,025 is required.

Therefore the District concludes that the project, upon your Board's approval of the attached Mitigation Agreement 20130092, conforms to the District's State Implementation Plan (SIP), and satisfies federal General Conformity and state CEQA requirements.

In addition, while the District has determined that Hydrogen Energy California LLC's proposal to construct this Project complies with all District regulations, including requirements for Best Available Control Technology and emissions offsets, the NOx emissions from the proposed plant are higher than those of a new natural gas fired base load power plant with similar output to the grid. Hydrogen Energy California LLC has agreed with the District's request that HECA provide additional voluntary mitigation, above that required by the District's rules and regulations, through a second Voluntary Emissions Reduction Agreement.

The quantity of NOx emissions to be mitigated was established using the following methodology (see further details in the attached Voluntary Emissions Reduction Agreement, specifically in Attachment B):

- The emissions from the plant during power production operations were calculated and compared to the emissions from a new natural gas fired base load power plant at the same output to the grid. The difference between these two values is the mitigation amount.

Based on the above methodology, 16.7 tons of NOx emissions are to be mitigated within the Valley for the life of the project. The mitigation fee for NOx emissions is $67,492.00 per ton, which is the 2011 weighted average price of all purchases of permanent NOx emission reduction credits (ERCs) in the San Joaquin Valley, plus 5% for administrative costs associated with the District implementing a grant program to bring about the intended NOx reductions. At these rates a sum of $1,181,135 is required.

The funds received under this Mitigation Agreement and Voluntary Emission Reduction Agreement will be used to provide contemporaneous emission reductions within the San Joaquin Valley to the extent possible near the new power plant and in Kern County. Emission reduction programs that will be funded will be the most cost-effective projects available and are likely to include replacement or retrofitting of heavy duty diesel internal combustion engines and electrification of agricultural pump engines.

Given the District's experience in administering grants for emission reduction projects, with adequate funding, the District can bring about sufficient emission reductions from existing sources of emissions to fully and permanently mitigate the air emissions from this development project. The emission reduction projects will permanently reduce emissions, because even after the useful life of the project has ended, the funded equipment, device or vehicle will be replaced with equipment, devices or vehicles that are as clean as or cleaner than the original.

District-identified projects are generally more cost-effective than this schedule, and therefore, actual funds received by the District for the Mitigation Agreement may be less than estimated. Projects will be verified by the District to ensure that reductions are

valid and each project will be field inspected by the District prior to and after installation. The District will also perform long term monitoring of the projects to ensure the emissions remain in place during the period of the agreement. Whether Hydrogen Energy California LLC or the District identifies projects, all will be under contract with the District to ensure their enforceability.

In conclusion, Table 1 presents the required emission reductions under each Agreement. The dollar value of these agreements are based on the emissions, as estimated by Hydrogen Energy California LLC and verified by the District, multiplied times the emission reduction schedule contained in Exhibit C of the Mitigation Agreement and Exhibit A of the Voluntary Emission Reduction Agreement.

The emission reduction projects will be in place contemporaneously with the development and will directly provide air quality benefits in Kern County and the south San Joaquin Valley. The District will establish a separate budgetary account for these mitigation funds, and will provide routine tracking and status reports documenting fund expenditures and the emissions reductions achieved for the development project.

Table 1 – Overall Funding Schedule

	Mitigation Agreement (MA)	**Voluntary Emission Reduction Agreement (VERA)**
NOx Total Tons	287.2	16.7
VOC Total Tons	61.3	0
PM10 Total Tons	39.5	0
Total Funding Under Agreement	$7,566,025	$1,181,135
Overall Funding	**$8,747,160**	

It should be noted that the two mitigation agreements, one for construction and mobile emissions and one for stationary source emissions, were kept separate at HECA's request, resulting in the two agreements before your Board today.

In summary, the action that staff is recommending your Board take today, specifically the approval of the two attached agreements, would not constitute an approval of the HECA project, but would establish critical components of the facility's ability to mitigate their emissions increases.

FISCAL IMPACT:

Under the terms of the agreements, Hydrogen Energy California LLC is expected to pay to the District approximately $8,399,915 in mitigation fees and $347,245 in administrative fees for a total of $8,747,160. The fees due for the construction emissions in the Mitigation Agreement will be paid to the District at least five (5) months prior to breaking ground for construction of the Project. The fees due for operational emissions in both the Mitigation Agreement and the Voluntary Emission Reduction Agreement will be paid to the District at least six (6) months prior to the commercial operation date of the Project.

To ensure contemporaneous reduction in emissions, the District intends to award these funds in accordance with a schedule that would allow emission reductions to begin taking place prior to emissions increases commencing. Staff will present adjustments to the District's budget for the Board's consideration at the appropriate times to coordinate the receipt of mitigation funds and the expenditure of those funds in accordance with the Mitigation Agreement and Voluntary Emission Reduction Agreement.

Attachments:
Attachment A: Hydrogen Energy California LLC Mitigation Agreement (18 pages)
Attachment B: Hydrogen Energy California LLC Voluntary Emission Reduction Agreement (7 pages)

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
April 18, 2013

APPROVE TWO MITIGATION AGREEMENTS WITH HYDROGEN ENERGY CALIFORNIA, LLC. TO RECEIVE FUNDS IN THE AMOUNT OF APPROXIMATELY $8,747,160 FOR THE PURPOSE OF MITIGATING AIR QUALITY IMPACTS OF A PROPOSED NEW POWER GENERATION FACILITY IN KERN COUNTY

Attachment A

MITIGATION AGREEMENT
(18 PAGES)

MITIGATION AGREEMENT 20130092

This Mitigation Agreement ("Agreement") is entered into as of April 18, 2013 by and between Hydrogen Energy California LLC ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT ("District"), an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

RECITALS

WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, and indirect sources; and

WHEREAS, Developer submitted an Amended Application for Certification (08-AFC-8A) seeking licensing from the California Energy Commission (CEC) which will permit the development of a Project located in the County of Kern, California, as more particularly described on Exhibit A attached hereto and incorporated herein (the "Project"); and

WHEREAS, the Project will cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit B attached hereto and incorporated herein (the "District Boundaries"); and

WHEREAS, the term "indirect" emissions as used in this Agreement refers to emissions from construction and transportation activities, as opposed to emissions from permitted stationary sources; and

WHEREAS, as a result of funding provided to the Project by the U.S. Department of Energy ("DOE"), the Project is subject to District Rule 9110 and Clean Air Act Section 176(c)(1) as implemented by 40 CFR Part 93 Subpart B, "Determining Conformity of Federal Actions to State or Federal Implementation Plans" (General

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Conformity); and

WHEREAS, Developer has prepared, and District staff has reviewed and concurred in, a General Conformity Evaluation for the Project, including air quality impact modeling for assessing indirect air quality emission impacts associated with construction and operation of the Project; and

WHEREAS, the General Conformity Evaluation demonstrates indirect emissions are expected to exceed the following Conformity Thresholds in the San Joaquin Valley Air Basin: 10 tons/year NOx, and 10 tons/year ROG/VOC; and

WHEREAS, District has determined that Developer's payment of fees into District's Emission Reduction Incentive Program (ERIP) will provide pound-for-pound offsets of Project indirect emissions that exceed the General Conformity thresholds and result in DOE's federal action conforming to the applicable state implementation plan (SIP), all as set forth in the General Conformity Evaluation for the Project; and

WHEREAS, the emission offsets that will be provided pursuant to this Agreement for purposes of satisfying the General Conformity requirements are distinct from and in addition to any new source review emission offsets that Developer is required to provide pursuant to District Rule 2201; and

WHEREAS, the Project is subject to review pursuant to the California Environmental Quality Act ("CEQA") codified at California Public Resources Code Section 21000, et seq.; and

WHEREAS, pursuant to its certified regulatory program, the CEC acts as CEQA lead agency for the Project and the District is a CEQA responsible agency for the Project; and

WHEREAS, District has determined, in its role as a CEQA responsible agency, that Project indirect emissions are expected to exceed the District CEQA Significance Thresholds of 10 tons/year NOx, 10 tons/year ROG/VOC and 15 tons/year PM10 and that additional mitigation measures beyond those proposed by Developer are necessary to mitigate Project indirect emissions below a level of significance; and

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WHEREAS, District has determined that Developer's payment of fees into District's Emission Reduction Incentive Program (ERIP) will further mitigate Project indirect emissions that exceed the District CEQA Significance Thresholds and result in Project indirect emissions being mitigated below the level of significance; and

WHEREAS, District has determined that with appropriate funding, District can provide additional reductions of emissions from certain projects in types and in sufficient quantities which, when combined with other measures proposed by Developer, will offset and mitigate Project criteria pollutant emissions for construction and operation , such that the Project will not result in significant impacts to air quality and the DOE action with respect to the Project will conform to the applicable SIP; and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which, when combined with other measures proposed by Developer, will offset and mitigate the emissions for the Project, so that the development of such Project will not result in an increase in criteria pollutant emissions over those which would otherwise exist without the development thereof; and

WHEREAS, District has determined that compliance with the terms of this Agreement will ensure that the Project will have no significant adverse impacts to air quality, and that DOE's action with respect to the Project will conform to the applicable SIP as more fully set forth in the General Conformity Evaluation prepared for the Project.

AGREEMENT

NOW, THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Offsetting and Mitigation of Project Related Impacts on Air Quality**

Project related indirect emissions from construction and operation that exceed applicable CEQA and General Conformity thresholds shall be offset and mitigated by achieving real, surplus, quantifiable and enforceable reductions of ROG/VOC, NOx,

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and PM_{10} through implementation of Emission Reduction Measures in accordance with this Agreement. The determination of whether proposed emission reductions are real, surplus, quantifiable and enforceable shall be performed by the District through its Strategy and Incentives Department. Estimated Project related indirect source emissions that exceed applicable CEQA and General Conformity thresholds are set forth in Exhibit C, which is attached hereto and incorporated herein, and shall be offset and mitigated as demonstrated in Exhibit C. For construction emission impacts, indirect emissions of any criteria pollutant exceeding the applicable General Conformity Threshold or District CEQA Significance Threshold in any given year will be fully offset and mitigated for that pollutant for the entire project construction period. For operational emission impacts, indirect emissions of any criteria pollutant exceeding the applicable General Conformity Threshold or District CEQA Significance Threshold will be fully offset and mitigated for that pollutant, as specified in Exhibit C.

2. **Payment of Air Quality Mitigation Fees**

No later than five months prior to breaking ground for construction of the Project, Developer shall pay Air Quality Mitigation Fees to District in the amount of three million three hundred twenty seven thousand three hundred thirty four dollars ($3,327,334) for implementation of Emission Reduction Measures to offset and mitigate Project construction emissions as specified in Exhibit C. The amount specified above includes a 4% administration fee to cover the District's costs of administering this Agreement.

No later than six months prior to the commercial operation date (COD) for the Project, Developer shall pay additional Air Quality Mitigation Fees to the District in the amount of four million two hundred thirty eight thousand six hundred ninety two dollars ($4,238,692) for implementation of Emission Reduction Measures to offset and mitigate Project indirect operational emissions as specified in Exhibit C. The amount specified above includes a 4% administration fee to cover the District's costs of administering this Agreement.

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3. **Implementation of Emission Reduction Measures**

Upon Developer's submission to District of the Air Quality Mitigation Fees specified in paragraph 2 above, District shall (1) use diligent efforts to enter into Funding Agreements with owners and/or operators of pollution source equipment to implement the Emission Reduction Proposals within 150 days (in the case of Emission Reduction Measures to offset and mitigate construction emissions) and 180 days (in the case of Emission Reduction Measures to offset and mitigate indirect operational emissions); (2) determine the types and quantities of permanent reduction in emissions which would be realized by the Emission Reduction Measures; (3) perform the determination of surplus emission reductions of ROG/VOC, NOx, and PM10; and (4) advise Developer of such determinations in writing.

District shall notify Developer or designee in writing of Funding Agreements entered into by the District. In the event District is unable to achieve the required reductions District shall provide Developer a written statement of the amount of reductions that have been achieved. Developer shall have a reasonable time, not to exceed ninety (90) days, within which to submit to District additional Emission Reduction Proposal(s) or provide District additional Air Quality Mitigation Fees.

4. **Refunds**

Upon verification by District that Project indirect emissions have been fully offset and mitigated in accordance with this Agreement, District shall refund Developer any unused Air Quality Mitigation Fees. District shall have reasonable time, not to exceed sixty (60) days, to refund Developer.

5. **CEQA & General Conformity Compliance**

District hereby confirms that with implementation of this Agreement: i) Project construction emissions of any criteria pollutant exceeding the General Conformity Threshold or District CEQA Significance Threshold in any given year will be fully offset and mitigated for that pollutant for the entire project construction period; and ii) Project indirect operational emissions of any criteria pollutant exceeding the General

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Conformity Threshold or District CEQA Significance Threshold will be fully offset and mitigated for that pollutant.

6. **District's Obligations**

6.1 **Acknowledgement Regarding Full Offset and Mitigation**

Upon successful implementation of the Emission Reduction Measures pursuant to Paragraph 3, District shall verify in writing to Developer, the CEC and the DOE that the Project related impacts on air quality have been fully offset and mitigated as set forth in Paragraph 5. For the purpose of this Agreement, fully offset and mitigated means that the reductions specified in Exhibit C have been achieved.

6.2 **Oversight of Funding Agreements**

District shall ensure that the owners/operators of equipment subject to Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements.

6.3 **Oversight of Air Quality Mitigation Monitoring Plan**

Upon request of the CEC, District shall oversee that portion of the mitigation monitoring plan adopted by CEC which relates to the mitigation brought about by this Agreement. Alternatively, upon request of the CEC, District shall cooperate with the CEC in the oversight of that portion of the mitigation monitoring plan adopted by the CEC for the Project which relates to the mitigation brought about by this Agreement.

6.4 **Documentation, Record Keeping and Monitoring**

District shall document, keep adequate records on and monitor the emission reductions brought about as a result of this Agreement, and shall, upon written request by Developer, the CEC or the DOE, provide Developer, the CEC or the DOE written reports verifying achieved emission reductions and/or emission reductions being brought about to fully offset and mitigate Project related impacts on air quality.

6.5 **Achievement of Emission Reductions**

For and in exchange of Developer's payment of funds pursuant to Paragraph 2 above, District shall ensure, by way of entering into, funding and enforcing the Funding

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Agreements in accordance with the provisions of this Agreement, that the Project achieves the required emission reductions to the extent specified in this Agreement. District shall ensure that implementation of Emission Reduction Measures to offset Project indirect operational emissions as specified in Exhibit C shall result in emission reductions in a timeframe complying with the general conformity mitigation requirements of 40 CFR 93.163.

7. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer**

In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Paragraph 2 above, then District shall acknowledge and credit Developer with the emission reductions achieved pursuant to this Agreement and any additional emission reductions achieved to mitigate the Project related impacts on air quality that will result from Developer's payment of such additional monies. To the extent that monies paid by Developer pursuant to Paragraph 2 above, when combined with monies paid pursuant to a District Approved Settlement, result in emission reductions in excess of those required to fully offset and mitigate Project related emissions as required by this Agreement, District shall refund to Developer any remaining Air Quality Mitigation Fees in excess of those required to achieve the emission reductions contemplated by this Agreement. For purposes of this Paragraph, a "District Approved Settlement" shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal or settlement of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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8. **Term of Agreement**

This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement Emission Reduction Measures that provide necessary emissions reductions to fully offset and mitigate the indirect Project related air impacts, including any associated monitoring, recordkeeping and reporting. Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the CEC and DOE that Developer has offset and mitigated indirect air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements and Emission Reduction Measures implemented as of the date of termination, (ii) District shall refund to Developer any unused portion of Developer's Air Quality Mitigation Fees less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement except as expressly provided. District's obligations to oversee implementation of Funding Agreements pursuant to Paragraph 9 and to ensure that required emission reductions are achieved, pursuant to Paragraph 9, shall remain effective for as long as necessary to ensure that the anticipated emission reductions continue to be achieved to the extent specified in this Agreement.

9. **Representations, Covenants and Warranties**

9.1. **Developer's Representations, Covenants and Warranties**.

Developer represents, covenants and warrants to District, as of the date of this Agreement, as follows:

9.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

9.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding

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obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

9.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

9.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

9.2. **District's Representations, Covenants and Warranties**

District represents, covenants and warrants to Developer, as of the date of this Agreement, as follows:

9.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

9.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

9.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

9.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents,

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confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

9.2.5. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

9.2.6. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

10. **Indemnification**

Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

11. **Inurement**

Developer's rights and obligations under this Agreement, or applicable portions thereof, shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer. Upon Developer's conveyance of all or any portion of the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

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12. **Assignment**

Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

13. **Recitals Incorporated**

The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

14. **Further Assurances**

Developer and District agree to execute and deliver any documents and/or perform any acts which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

15. **No Joint Venture or Partnership**

District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making

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(559) 230-6000

District and Developer joint venturers or partners.

16. **Notices**

Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this paragraph, (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

DEVELOPER	**DISTRICT**
Hydrogen Energy California, LLC 30 Monument Square, Suite 235 Concord, MA 01742 Fax: (978)287-9529 Attn: Marisa Mascaro	Seyed Sadredin Executive Director/APCO 1990 E. Gettysburg Avenue Fresno, CA 93726 (559) 230-6000 Fax: (559) 230-6061

17. **Entire Agreement**

The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to the subject matter of this Agreement.

18. **Amendments and Waivers**

No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in

writing and signed by the waiving party.

19. **Invalidity of Provisions**

If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision, which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

20. **Construction**

Unless otherwise indicated, all paragraph references are to the paragraph of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

///

///

SJVUAPCD
1990 E. Gettysburg
Fresno, CA 93726
(559) 230-6000

21. **Governing Law**

This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

22. **No Third-party Beneficiaries**

Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

23. **Exhibits**

The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

24. **Force Majeure**

The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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SJVUAPCD
1990 E. Gettysburg
Fresno, CA 93726
(559) 230-6000

IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER

Hydrogen Energy California LLC

James L. Croyle
Chief Executive Officer

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

Skip Barwick
Governing Board Chair

Recommended for approval:
San Joaquin Valley Unified Air Pollution Control District

Seyed Sadredin
Executive Director/APCO

Approved as to legal form:
San Joaquin Valley Unified Air Pollution Control District

Catherine Redmond
District Counsel

Approved as to accounting form:

Cindi Hamm
Director of Administrative Services

For accounting use only:
San Joaquin Valley Unified Air Pollution Control District

Program: _____
Account No: _____

SJVUAPCD
1990 E. Gettysburg
Fresno, CA 93726
(559) 230-6000

EXHIBIT A

DESCRIPTION OF THE PROJECT

The HECA IGCC polygeneration project is located near the community of Tupman, as shown in Figure 1. The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). The HECA Project Site comprises a 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based fertilizer Manufacturing Complex, and associated equipment and processes (excluding off-site portions of linear facilities), will be located. HECA has an agreement to purchase the HECA Project Site, as well as an additional 653 acres adjacent to the HECA Project Site, herein referred to as the Controlled Area. HECA will have control over public access and future land use on this property. In addition, the HECA Project will include the following linear facilities, which extend off the Project Site.

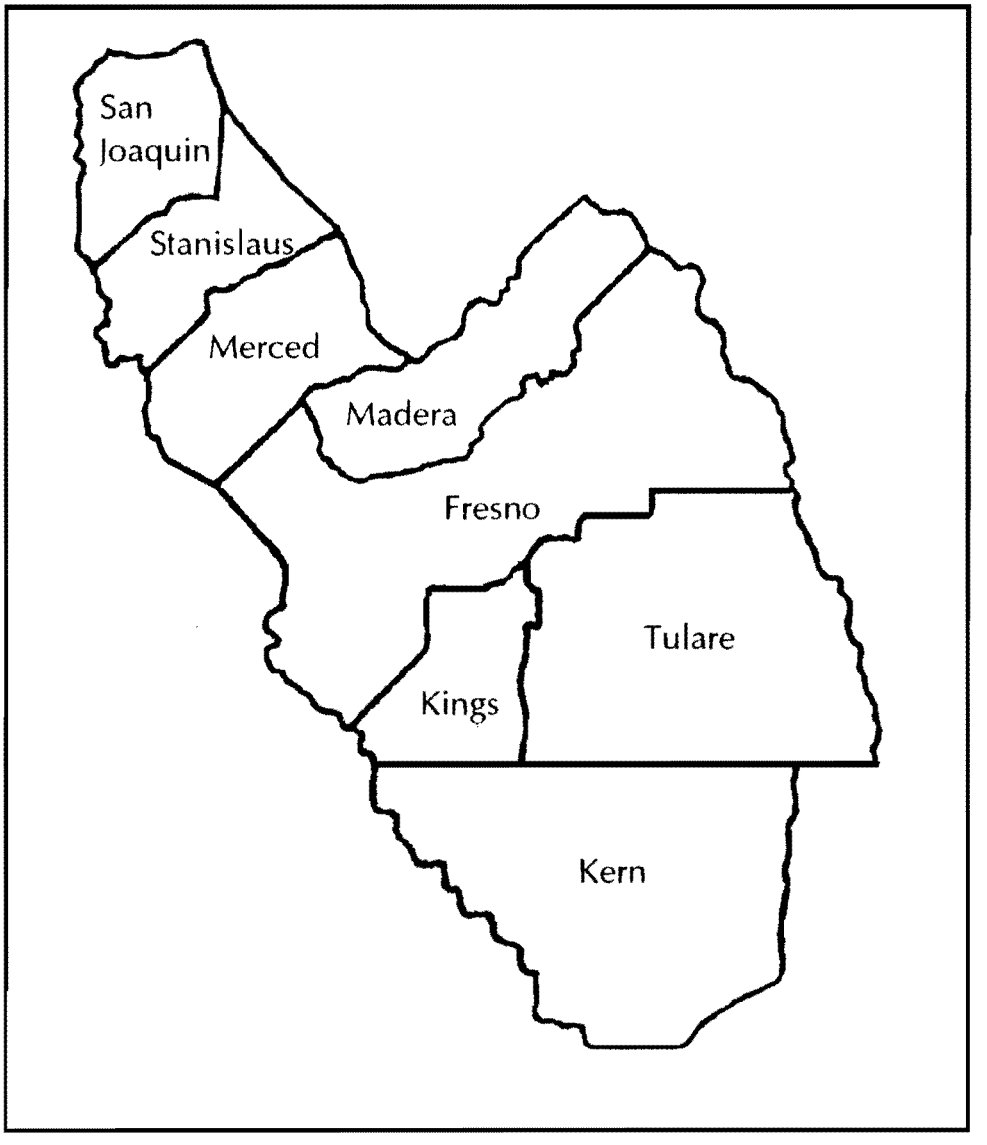
- Electrical transmission line. An approximately 2-mile-long electrical transmission line will interconnect the Project to a future Pacific Gas and Electric Company (PG&E) switching station east of the Project Site.

- Natural gas supply pipeline. An approximately 13-mile-long natural gas interconnection will be made with PG&E natural gas pipelines north of the Project Site.

- Water supply pipelines and wells. An approximately 15-mile-long process water supply line and up to five new groundwater wells will be installed by the Buena Vista Water Storage District (BVWSD) to supply brackish groundwater from northwest of the Project Site. An approximately 1-mile-long water supply linear from the West Kern Water District (WKWD) east of the Project Site will provide potable water.

EXHIBIT B

DISTRICT BOUNDARIES



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1990 E. Gettysburg
Fresno, CA 93726
(559) 230-6000

EXHIBIT C

PROJECT EMISSION MITIGATION FEES

HECA	ALT 1 - TRAIN			ALT 2 - TRUCKS		
	NOx	PM_{10}	VOC	NOx	PM_{10}	VOC
2013 Construction	50.1	25.9	5.5	50.1	25.9	5.5
2014 Construction	69.0	15.4	11.9	69.0	15.4	11.9
2015 Construction	68.6	10.5	12.4	68.6	10.5	12.4
2016 Construction	45.8	8.1	8.4	45.8	8.1	8.4
2017 Construction	10.1	1.4	1.3	10.1	1.4	1.3
2017 Operation	13.3	1.4	0.6	14.5	2.9	1.1
2018 Operation and beyond	39.9	4.2	1.9	43.6	8.6	3.2
District CEQA Thresholds	10	100	10	10	100	10
Conformity Threshold	10	15	10	10	15	10

Notes: This agreement provides mitigation for all shaded values:

~ The highest emitting alternative scenario for operations and construction is the alternative in which all deliveries and shipments are made by truck (ALT 2)

~ All construction emissions (NOx, PM_{10} and VOC) are mitigated

~ All operational indirect source NOx emissions are mitigated at the maximum single year value of 43.6 tons per year. Operational PM_{10} and VOC emissions do not exceed the District's significance thresholds.

	Per Year
NOx and VOC $/ton (ISR)	$ 9,350
PM10 $/ton (ISR)	$ 9,011

Mitigation

Construction:	344.4	tons, total (NOx+VOC+PM10)
	$ 3,327,334	
Operation:	43.6	tons/yr (NOx), max year
	$ 4,238,692	
Total Mitigation Amount:	$ 7,566,025	Includes a 4% administration fee

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
April 18, 2013

APPROVE TWO MITIGATION AGREEMENTS WITH HYDROGEN ENERGY CALIFORNIA, LLC. TO RECEIVE FUNDS IN THE AMOUNT OF APPROXIMATELY $8,747,160 FOR THE PURPOSE OF MITIGATING AIR QUALITY IMPACTS OF A PROPOSED NEW POWER GENERATION FACILITY IN KERN COUNTY

Attachment B:

VOLUNTARY EMISSION REDUCTION AGREEMENT

(7 PAGES)

HYDROGEN ENERGY CALIFORNIA POWER PLANT PROJECT
VOLUNTARY EMISSION REDUCTION AGREEMENT 20130026

This Voluntary Emission Reduction Agreement ("Agreement") is entered into this 18th day of April, 2013 by and between Hydrogen Energy California LLC, a Delaware limited liability company ("HECA"), and the San Joaquin Valley Air Pollution Control District (the "District"). HECA and the District may be referred to individually as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, on May 3, 2012, HECA filed an Amended Application for Certification ("Amended AFC") with the California Energy Commission ("CEC") for the Hydrogen Energy California Power Plant, a nominal 405 megawatt facility that will produce a nominal 300 net megawatts of base-load, low-carbon electricity by gasifying coal and/or petroleum coke to produce hydrogen for electric generation in an integrated gasification combined cycle plant, capturing carbon dioxide to be delivered via pipeline for use in enhanced oil recovery and resulting sequestration in the oil fields located in Kern County, California, and producing low-carbon fertilizer in an Integrated Manufacturing Complex (the "Project"); and

WHEREAS, HECA is seeking approval from the CEC to construct and operate the Project; and

WHEREAS, on June 4, 2012, HECA filed a revised Application for Authority to Construct ("ATC") with the District for the Project; and

WHEREAS, HECA and the CEC are seeking a Final Determination of Compliance ("FDOC") for the Project from the District; and

WHEREAS, the Project site will occupy a portion of a 453 acre site that is located approximately 7 miles west of the outermost edge of the City of Bakersfield and approximately 2 miles northwest of the unincorporated community of Tupman in Western Kern County; and

WHEREAS, the District has determined that the Project, as proposed, complies with all applicable requirements for its stationary source emissions, including all requirements related to emission offsets and best available control technology ("BACT"); and

WHEREAS, notwithstanding that the Project complies with all applicable requirements for its stationary source emissions, the District desires that HECA further mitigate its stationary source NOx emissions to a level equivalent to that achieved by a natural gas power plant supplying the same amount of electricity to the grid; and

WHEREAS, HECA desires to cooperate with the District by entering into this Agreement to provide additional air quality benefits, despite being under no legal obligation to do so; and

WHEREAS, the District and HECA have determined that payment of a voluntary emission reduction fee to be used for air quality benefit programs, to the extent feasible, within

Kern County, or within the San Joaquin Valley with quantifiable direct or indirect benefits to the air quality of Kern County, is the appropriate method for HECA to ensure additional air quality benefits within the District.

NOW THEREFORE, for good and valuable consideration, including the mutual covenants set forth herein, HECA and the District hereby agree as follows:

1. Recitals. All recitals above are incorporated herein by this reference.

2. Voluntary Emission Reduction Fee. Subject to the conditions precedent set forth in Section 3 below, HECA agrees to contribute to the District the total sum of One Million One Hundred Eighty One Thousand One Hundred Thirty Five Dollars ($1,181,135), which includes a five percent (5%) administration fee, to ensure additional air quality localized benefits within the District, and, in particular, direct or indirect benefits in Kern County (the "Voluntary Emission Reduction Fee"). An outline of the methodology used to determine the amount of the Voluntary Emission Reduction Fee and the calculation of the Voluntary Emission Reduction Fee are attached hereto as Exhibit A, incorporated herein by this reference. HECA agrees to pay the Voluntary Emission Reduction Fee to the District no later than six months prior to the commercial operation date ("COD") for the Project.

3. Conditions Precedent. The Parties acknowledge and agree that HECA's obligation to pay the Voluntary Emission Reduction Fee shall be subject to the fulfillment or waiver (such waiver to be in HECA's sole discretion) of both of the following conditions precedent:

(a) Issuance of the final CEC certification for the Project; and

(b) Physical delivery of the combustion turbine generator to the Project site.

Notwithstanding the above, if the Amended AFC with the CEC has been cancelled, withdrawn or denied, or if the Project is certified but not constructed during the term of the CEC's certification, then this Agreement shall automatically terminate, and neither Party shall have any further obligations hereunder.

4. Use of Voluntary Emission Reduction Fee. The District agrees to set up a specific account into which the Voluntary Emission Reduction Fee will be deposited. The District agrees to use the Voluntary Emission Reduction Fee exclusively to establish specific programs that create air quality benefits within the District. The District, in consultation with HECA, will identify the most effective and appropriate programs in which to invest the Voluntary Emission Reduction Fee. In particular, the District will work to establish that:

- programs selected to receive funding will focus on replacing agricultural equipment, including old tractors and old haul trucks operating, to the extent possible, within Kern County, or within nearby communities in the San Joaquin Valley with quantifiable direct or indirect benefits to the air quality of Kern County,

- assurance is provided that the equipment replaced through the use of funds is in regular use and not already idled,

- opportunities to participate in programs are provided to smaller users that regularly use high emitting equipment,

- programs selected to receive funding will benefit, to the extent possible, Kern County to ensure emissions reductions occur locally, and

- programs selected to receive funding will also, in general, reduce other criteria pollutants and greenhouse gases (GHGs) at the same time as reducing NOx emissions.

The District agrees to share with HECA the data regarding the actual NOx (and GHGs and other criteria pollutants to the extent data is readily available) emission reduction volumes achieved through the Voluntary Emission Reduction Fee funded programs.

The District agrees not to place the Voluntary Emission Reduction Fee into any operating account, or to use the Voluntary Emission Reduction Fee for any purpose other than those designated in this Agreement.

5. Cooperation. The Parties agree to cooperate with each other with respect to any requests or actions related to this Agreement from the CEC, the U.S. Environmental Protection Agency, or the California Air Resources Board, and to do or cause all things reasonably necessary, proper or advisable to help consummate and make effective the transaction contemplated by this Agreement.

6. Governing Law. This Agreement shall be governed by, construed under and enforced in accordance with the laws of the State of California.

7. Authority. Each Party acknowledges and agrees that it has the full right, power and authority to execute this Agreement, and to perform its obligations hereunder.

8. Relationship of the Parties. Nothing herein is intended to create or is to be construed as creating a joint venture, partnership, agency or other taxable entity between the Parties. The rights and obligations of the Parties shall be independent of one another and shall be limited to those expressly set forth herein and, except as expressly provided to the contrary, shall not be construed to apply to any affiliate of the Parties.

9. No Third Party Beneficiary. The Parties mutually agree that this Agreement is for their sole benefit and is not intended by them to be, in part or in whole, for the benefit of any third party.

10. Notices. All notices necessary to be given under the terms of this Agreement, except as herein otherwise provided, shall be in writing and shall be communicated by prepaid mail, telegram or facsimile transmission addressed to the respective Parties at the address below or to such other address as respectively designated hereafter in writing from time to time:

To HECA: HYDROGEN ENERGY CALIFORNIA LLC
30 Monument Square, Suite 235
Concord, MA 01742
Attn: Ms. Marisa Mascaro
Phone: 978-287-9529
Fax: 978-287-9512

To District: San Joaquin Valley APCD
1990 East Gettysburg Avenue
Fresno, CA 93726-0244
Attn: Mr. David Warner
Phone: (559) 230-5900
Fax: (559) 230-6061

11. Assignment. This Agreement shall be binding upon, and inure to the benefit of, each of the Parties and their respective successors and permitted assigns. No Party shall assign this Agreement or its rights or interests hereunder without the prior written consent of the other Party, such consent not to be unreasonably withheld or delayed. Notwithstanding the above, the Parties agree that HECA may freely assign its rights and duties under this Agreement, without District's prior written consent, to: (a) an affiliate of HECA; (b) a successor-in-interest by merger, consolidation or reorganization; (c) a purchaser or other transferee of the Project; or (d) a lender for purposes of financing the Project.

12. Entire Agreement and Amendment. This Agreement, together with the Exhibits attached hereto, contains the entire understanding between the Parties with respect to the subject matter herein. This Agreement may not be amended except by an instrument in writing signed by each Party.

13. Joint Effort. The Parties acknowledge and agree that each Party and its counsel have read this Agreement in its entirety, fully understand it, and accept its terms and conditions. Accordingly, the normal rule of construction to the effect that any ambiguities are to be resolved against the drafting party is not applicable and therefore shall not be employed in the interpretation of this Agreement or any amendment of it.

14. Counterparts. This Agreement may be executed in counterparts (including by facsimile or e-mailed Adobe® portable document format file), all of which shall constitute one document, and that by the signature(s) hereto, the undersigned further agree that facsimile or e-mailed Adobe® portable document format file signatures shall be effective for all purposes.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement the day and date first above written.

HYDROGEN ENERGY CALIFORNIA LLC

By:_____ Dated: 4/10/2013
James L. Croyle
Title: Chief Executive Officer

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

By:_____ Dated: 4/18/13
Skip Barwick, Chair
Governing Board
San Joaquin Valley APCD

Approved:

By:_____ Dated: 4/18/13
Seyed Sadredin
Executive Officer/Air Pollution Control Officer
San Joaquin Valley Air Pollution Control District

Approved as to Legal Form:

By:_____
Catherine Redmond
District Counsel

Approved as to Accounting Form:

By:_____
Cindi Hamm,
Director Administrative Services

Exhibit A

PART A-1

Outline of Methodology

To calculate the increased emissions from the Project compared with a new natural gas fired power plant, the emissions from the Project will be calculated as proposed and as they would be if the Project emitted at the same pounds of NOx per MW-hour rate as that of a recently licensed natural gas fired power generating facility. The difference between these two values is the mitigation amount (see Table 1 of Part A-2).

The fee is then calculated by multiplying the mitigation amount by the weighted average cost of purchasing NOx Emission Reduction Credits (ERC) in the San Joaquin Valley as reported in 2011 ($67,492/ton NOx), plus 5% for administrative costs (see Table 2 of Part A-2).

PART A-2

Table 1: Turbine Emission Comparison

Annual Basis	Natural Gas[1]	HECA[2]
Net Megawatt-hours (MW-hr/yr)	3,023,388	2,243,040
NOx emissions (tpy)	144	123.5
NOx emissions per MW-hr (lb/MW-hr) net	0.09526	.0110
Natural gas equivalent NOx emissions (tpy) with HECA net MW-hr/yr	106.8	

Notes:

1 – Information for a representative natural gas fired power plant was taken from the proposed emissions from the Avenal Energy Center's Application for Certification and CEC Final Staff Assessment.

2 – HECA emissions include heat recovery steam generator and coal dryer emissions with hydrogen-rich fuel and natural gas usage including startup and shutdown.

Table 2: Cost Calculations

Project	NOx (tons/year)	Difference (tons/year)	Cost of ERC ($/ton)	VERA fee ($)*
HECA	123.5	16.7	67,492	1,181,135
Natural gas equivalent	106.8			

*Includes 5% administrative fee to cover District costs of contracting and administering emissions reductions

APPENDIX M
Comments Received During PDOC Comment Period

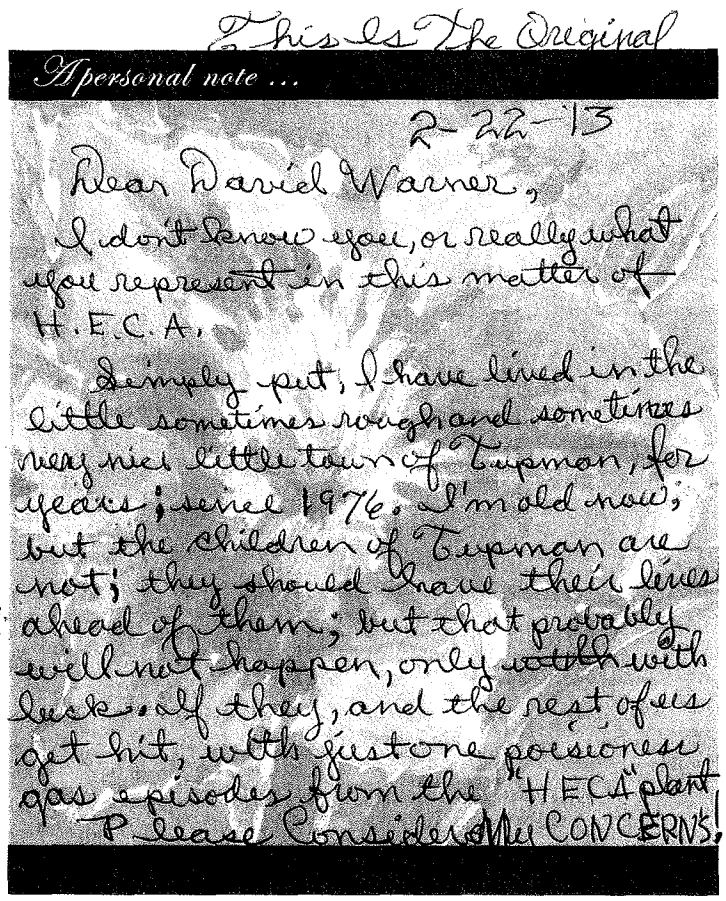
FROM:

SARAH E. GOATCHER
PO Box 37
TUPMAN, CA. 93276

2-22-2013

Life Is The Longest
Shortest Journey
We Will Ever Pass
Through!
If we are lucky; we might
do it, with a clear conscious!

Love Shaya Goatcher


This Is The Original
A personal note ...
2-22-13
Dear Daniel Warner,
I don't know you, or really what you represent in this matter of H.E.C.A.,
Simply put, I have lived in the little sometimes rough and sometimes very nice little town of Tipman, for years; since 1976. I'm old now; but the children of Tipman are not; they should have their lives ahead of them; but that probably will not happen, only with luck, all they, and the rest of us get hit, with first one poisonous gas episodes from the "HECA" plant.
Please Consider My CONCERNS.

A personal note ...

Life, doesn't seem to matter anymore in the U.S. - "US"! Just the almighty dollar! OUR We matter, All of my Ancestors have fought many terrible battles! Some Won, some Lost! I will not go down without A Fight! I'm here, I CARE Lyzz

A personal note ...

It isn't just the Poison Gases (Emissions), It is the water table of the future, and eyes of now! The horrible Air pollution, the tremendous erosion of a beautiful farmland. O, h, and might I add the wild-life.

Everyone seems to be forgetting and sleeping under the carpet.

I live here, love them everyday, I love them, I protect them, they were here first, frogs, coyotes, owls, eagles, buzzards, squirrels, kit foxes, rabbits, lizards, tarantulas, all snakes, funny centipedes, ants, BEES, Ring Tails

The MICE, SHREWS, Kangaroo Rat Etc.

A personal note ...

They are all here, many more that I don't see; but are necessary for what they represent!

Do you really call this progress? Or do you care? I call it the destruction of what is left of a beautiful land, a corner of existence; that should be left in peace; as it does now exist!

In the name and of the heart of the Goddess & God

So Mote It Be

Lyzz

Homero Ramirez

From: Leonard Scandura
Sent: Thursday, March 07, 2013 3:43 PM
To: Homero Ramirez
Subject: verbal comment on HECA PDOC

Summary of verbal comment received by Leonard Scandura (LS) via telephone 3/7/13 3:00 pm
Trudy Douglas (TD) 661-834-4889

TD – Why was the Shafter monitoring site used in in doing the PSD modeling

LS – This site is the closest site to the HECA location, and was thought to best represent air quality in that vicinity

TD – But in the staff report for the adoption of Rule 2410 – page 3, under pre and post construction monitoring, it says that background from certain monitoring sites can be considered more conservative and should be used. Why didn't you use the Arvin monitor?

LS – As I said, the Shafter site is more representative of the facilities location,. I'll try to have a more complete answer for the public hearing

TD – Arvin site should be used in the modeling. Otherwise effects of the project may result in acid rain.
TD - Is there a website where I can post and view all public comments. How will you address comments?

LS – there is no website in which you can post comments. Comments can be mailed to us or via email at leoanrd.scandura@valleyair.org. When we make our final decision we will summarize all of the comments received and address each comment.

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512
ww.energy.ca.gov

March 28, 2013

Mr. David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

Re: Comments on the Hydrogen Energy California Project (08-AFC-8A)
Preliminary Determination of Compliance (PDOC)

Dear Mr. Warner,

Energy Commission staff have reviewed the San Joaquin Valley Unified Air Pollution Control District's (District) Preliminary Determination of Compliance (PDOC) for the Hydrogen Energy California (HECA) project and have the following comments for your consideration for inclusion in the Final Determination of Compliance (FDOC).

Comments on PDOC Engineering Evaluation

Rule 2201 Compliance Issues
Staff believes that there are two Rule 2201 compliance issues that require revisions. First, and most importantly, Section 4.8.1 of this rule requires a volatile organic compound (VOC) distance offset ratio of 1.5:1, not 1.3:1. Second, staff believes that the DOC needs to mention that particulate matter less than 2.5 microns (PM2.5) best available control technology (BACT) is required for the project's emissions sources since PM2.5 is listed as an affected pollutant in Section 3.4 of the rule. Staff recognizes that this request is perfunctory since particulate matter less than 10 microns (PM10) BACT would be the same as PM2.5 BACT, but we still believe that it should be clearly noted in the FDOC that BACT is also required for PM2.5 emissions.

Federal MATS Rule Compliance
Staff believes that compliance with the federal Mercury and Air Toxics Standards (MATS) rule (40 CFR 63, Subpart UUUUU) needs to be discussed in the engineering evaluation, and that appropriate conditions need to be added to assure rule compliance. While staff acknowledges that enforcement of the MATS regulation has been stayed by the United States Environmental Protection Agency (U.S. EPA) in response to petitions for administrative reconsideration, this does not mean the regulation has been revoked. In fact, the proposed rule update was published in the Federal Register on November 30, 2012, and the public comment period ended on January 7, 2013. Therefore, the District should assume that by the time the project begins operation, the MATS

regulation will be in force and provide necessary permit conditions for MATS rule compliance. The affected sources are the combustion turbine generator/heat recovery steam generator (CTG/HRSG) and coal dryer that need to meet the particulate, mercury, and hydrogen chloride emission limitations of this rule. Specific conditions should relate to the emissions limits in the MATS rule for Integrated Gasification Combined Cycle sources; and provide for emission control system monitoring and maintenance requirements, such as activated carbon change out requirements, for the mercury emissions control systems.

SO_2 for PM10 Interpollutant Offset Ratio

Staff is concerned that the approved 1 to 1 sulfur dioxide (SO_2) for PM10, and by proxy SO_2 for PM2.5 interpollutant offset ratio, which is a much lower ratio than has been allowed in past projects, would not provide for a net air quality benefit. The distance offset ratio for PM2.5 is also 1 to 1, meaning that regardless of the distance of the SO_2 emission reduction credits, the total approved SO_2 for PM2.5 ratio for the HECA project is 1 to 1. Staff would like to see additional analysis that supports the use of this offset ratio in the FDOC. Staff is also aware that the District's Governing Board approved the District's 2012 PM2.5 Plan for inclusion in the State Implementation Plan (SIP) in December 2012, which was then approved by the California Air Resources Board (ARB) on January 24, 2013. That plan calls for a 4.1 to 1 sulfur oxides (SOx) for PM2.5 interpollutant offset ratio for the San Joaquin Valley, based on changes to the method of interpollutant offset ratio determination due to the former District method being rejected by U.S. EPA. Staff would like to understand why the older U.S. EPA-rejected interpollutant offset ratio determination method is still being used for HECA, and why the 2012 PM2.5 Plan's updated interpollutant offset ratio is not being required for the HECA project. Would the U.S. EPA accept this more modest interpollutant offset ratio for HECA due to the date the application was deemed complete by the District?

Mitigation Agreement

Staff is requesting that the FDOC provide more details on the mitigation agreement(s) that the District is entering into with the project applicant. Specifically, staff is requesting that a copy of the agreement be provided as an appendix to the FDOC; and requests that the timing of the payment of fees and the requirements or goals for use of the emissions-reduction funds, such as being preferentially used to create emissions reduction in the San Joaquin Valley portion of Kern County as close to the project site as possible, be clearly identified in the attached agreement or otherwise stated in the FDOC.

Cooling Tower PM2.5 Fraction Assumption

Staff does not agree with the District's statement on page 33 of the engineering evaluation that notes that the PM10 and PM2.5 fractions for the cooling tower PM emissions are conservative. Staff does agree that the PDOC is mildly conservative for PM10 when it assumes 100 percent of the cooling tower PM is PM10. However, staff believes that the rationale used by the applicant for the ratio of PM2.5 to PM10 of 0.6:1 for the cooling tower emissions is flawed. The rationale provided by the applicant notes

that this ratio is cited in the South Coast Air Quality Management District's (SCAQMD's) particulate size fraction in the California Emission Inventory Development and Reporting System (CEIDARS) table from the SCAQMD California Environmental Quality Act (CEQA) website. However, the CEIDARS particulate size fraction data was originally produced by the ARB and review of the original CEIDARS particulate size fraction table from ARB shows that there is no cooling tower category. In the SCAQMD's version of the CEIDARS table, ARB's "unspecified" category for a PM10 to PM2.5 ratio was used in lieu of other available data for cooling towers. This shows that this particulate size fraction data is not specific to cooling towers and is not technically supportable. Staff believes that at least one specific CEIDARS category could be more representative of cooling towers than the "unspecified" category, namely the PM Profile ID #200 for evaporation that provides a PM10 fraction of 0.96 and PM2.5 fraction of 0.925.

Staff is willing to accept a defensible cooling tower particulate size fraction reference; however, to date staff is not aware of such a defensible reference. Staff believes that the District should investigate this further and if possible provide a more technically defensible particulate size fraction reference and revise the cooling tower particulate matter (PM10 and PM2.5) emissions appropriately. If no specific particulate size fraction data reference for cooling towers is available, to be more protective of public health the District should assume 100 percent of the PM10 is PM2.5.

Appendix K – Ambient Air Quality Impact and Health Risk Report
Staff believes that the background concentrations used should reflect the requirements of the standard. Staff believes that exceptional event data, as provided in the U.S. EPA AirData website database (http://www.epa.gov/airquality/airdata/ad_rep_mon.html) should be used to determine the background used for National Ambient Air Quality Standards (NAAQS) modeling analysis. Staff believes that showing background and modeled impact concentrations that are both well above the PM10 24-hour NAAQS, when the air basin is in compliance with this NAAQS, is not providing an accurate portrayal of the actual background or project impacts. Therefore, we suggest that the FDOC use background data that excludes exceptional event data that can be obtained from the U.S. EPA AirData website for the NAAQS impact analysis.

Staff also notes that the following statement on page 32 does not appear to be correct. *"The modeled maximum concentrations of SO2, NO2, PM2.5 and PM10 are also significantly below the secondary NAAQS that have been established by EPA."* While this statement is true for SO_2, nitrogen dioxide (NO_2), and PM10, the ambient and ambient plus project impact concentrations of PM2.5 are both above the secondary NAAQS. Therefore, staff believes that this statement needs to be revised.

Comments on PDOC Conditions

Mitigation Agreement Conditions (All Permit Units)
There are two conditions covering mitigation agreements to fund emissions reductions, provided as Conditions 1 and 2 for all permit units. However, the PDOC only provides

information on one such agreement. Having two conditions is confusing, doesn't seem to use the same nomenclature for the mitigation agreement provided in Appendix G of the PDOC, and may be redundant. Please also see the comment above on the engineering evaluation regarding the voluntary emissions reduction funding agreement(s).

Gasification Solids Material Handling and Storage (S-7616-22-0) Condition 24
Staff requests that a specific reference method, such as an American Society for Testing and Materials (ASTM) method, be added to the condition to define the requirements in "bringing the sample to dryness in a drying oven."

Combined-Cycle Power Generating System (S-7616-26-0) Condition 85
The first sentence of Condition 85 establishes that the California Department of Oil, Gas and Geothermal Resources (DOGGR) will be the responsible agency for approval of the OEHI MRV Plan. However, this is not the case at this time based on current regulations. Currently, the Energy Commission would be the responsible agency for ensuring CO_2 sequestration. We believe this will change at some point as more regulations are promulgated, but we cannot at this time confirm that DOGGR will be the agency responsible for MRV approval. Therefore, staff requests that sentence be revised as follows:

"Except as noted below, the separated pre-combustion CO_2 stream shall be transported to and sequestered by Occidental of Elk Hills (OEHI) in compliance with the latest OEHI CO_2 EOR Project Monitoring, Reporting and Verification (MRV) Plan, or equivalent, that has been approved by the responsible state agency to assure sequestration of the CO_2 transported to and used by the OEHI CO_2 EOR Project."

Combined-Cycle Power Generating System (S-7616-26-0) Conditions 86
The District is not the responsible agency for assuring compliance with the SB 1368 Emissions Performance Standard (EPS). Regulations implementing SB 1368 identify the California Public Utilities Commission as the responsible agency for investor-owned utilities and the Energy Commission as the responsible agency for publicly-owned utilities. Furthermore, the emissions limit in this condition as written cannot be complied with given the EPS calculation method currently proposed by staff. Staff suggests that this condition be revised to provide a CO_2 emissions limit on the GHG BACT finding and that the calculation of the CO_2 emissions used for compliance with this condition be provided in the condition or in additional conditions. Staff also would like to note that we believe that the CO_2 emissions calculation to be used to demonstrate compliance with the CO_2 BACT limit should at a minimum include the emissions from the CTG/HRSG, coal dryer, and CO_2 vent.

Coal Dryer Condition Clarification
The coal dryer is mentioned to be part of permit unit S-7616-20, but all of the coal dryer conditions are located within the permit for unit S-7616-26 where it is not mentioned in the permit unit description. For clarity, staff believes that the coal dryer should either be

removed from the description from permit unit S-7616-20 and added to the description of permit unit S-7616-26, or provided as a separate permit unit.

Firewater Pump Engine (S-7616-40-0) Condition 14
Condition 14, while appropriate for the emergency generator engines, does not seem appropriate for the firewater pump. Staff recommends that this condition be deleted or revised to describe what should be a fire based emergency definition.

Condition Ordering
Staff would prefer that the District provide general facility-wide conditions separately from the permit unit-specific conditions. However, assuming the District won't change that policy, staff requests that the District re-order the conditions so that the general conditions, and the conditions that would be complied with and removed by the time of Permit to Operate is issued, are moved to the end of the condition list for each permit unit. This would simplify the permit condition numbering and coordination between the District and the Energy Commission, particularly for potential project amendments, allowing for condition number consistency between agencies throughout the project's life.

Staff is continuing its review of the PDOC while completing the Preliminary Staff Assessment for HECA and may provide additional comments prior to the April 17th comment deadline if any new major issues are discovered. If you have any questions, please contact Gerry Bemis of my staff at (916) 654-4960. Thank you for the opportunity to comment on the Hydrogen Energy California Project's Preliminary Determination of Compliance.

Sincerely,

MATT LAYTON, Manager
Engineering Office
Siting, Transmission and Environmental
Protection Division

cc: Docket

Homero Ramirez

From: Bemis, Gerry@Energy <Gerry.Bemis@energy.ca.gov>
Sent: Tuesday, April 02, 2013 9:48 AM
To: Homero Ramirez
Subject: FW: PM2.5 Tupman in Danger-Enviromental Justice

Homero:

Just in case these comments (see below) are helpful for your meeting tonight. I presume Ms Douglass will attend and may make the statement she wrote below.

-- Gerry

From: Worl, Robert@Energy
Sent: Friday, March 29, 2013 4:10 PM
To: William Walters; Bemis, Gerry@Energy; Fletcher, Nancy@Energy; Dr. Alvin Greenberg; Chu, Ann@Energy
Cc: DeCarlo, Lisa@Energy; Heiser, John@Energy
Subject: FW: PM2.5 Tupman in Danger-Enviromental Justice

These comments were sent to us, I assume that the public advisor will docket and post on Tuesday, if not I will do so. Will wanted you to be aware of the comments prior to the Districts PDOC hearing on Tuesday. bobw

From: Trudy Douglass [mailto:trudydouglass@att.net]
Sent: Friday, March 29, 2013 4:04 PM
To: Worl, Robert@Energy; Energy - Public Adviser's Office; leonard.scandura@valleyair.org
Cc: loreleio@co.kern.ca.us; Jane.Warner@lung.org; bonnie.holmes-gen@lung.org; evan.gillespie@sierraclub.org; web.boardmail@valleyair.org
Subject: PM2.5 Tupman in Danger-Enviromental Justice

The San Joaquin Valley Air Pollution Control District seems to believe that particulates PM2.5 and smaller can be released into the air without any consequences or the need to account for them. In the in Preliminary Determination of Compliance for HECA PM2.5 fine particulate analysis was excluded from: 6.6.1, Pollutants with Significant Emissions Rates, 7.1,impact on Soil and Vegetation, 8.2.8, Potential to Emit greater 100 pounds in one day, 9, Health Risk Analysis.

The American Lung Association and American Cancer Society both have studies linking PM2.5 particulates and smaller to lung cancer and heart disease and all reparatory diseases. They are some of the most dangerous particulates because they can pass through the body's defenses and settle in the lungs. Children and the elderly are especially vulnerable.

I am sure that all the HECA factory workers will all be using breathing masks but the men, women, and children living in Tupman will have no protection. HECA's stack may blow some emissions above their town but these fine particulates generated at ground level will not leave the valley. Particulates PM2.5 and smaller will be streaming from almost every operation in the HECA factory: loading, transporting, unloading, grinding, blending, drying, conveying, and storing. They will come from every material brought in or manufactured: coal, coke, urea, sulfur, ammonium nitrate, factory waste and products. Even in the gasification process, HECA assumes that the sub-micron range will be PM10 but they could as well be PM2.5. Fine particulates will be in every breeze that passes through Tupman. (If this isn't bad enough, VI,p.36 unnamed "Fugitive Emissions" can escape at any time.)

From the first day of construction on HECA the air in Tupman and the area surrounding the factory will become a loaded gun waiting to go off inside any person living or working in the vicinity of the plant. Tupman will just be the first to experience this polluted haze because after 30 years of HECA the whole Southern San Joaquin Valley will be full of the particulates.

There is no way that CEC, the District or HECA can accurately predict pollution emissions because there are no parameters set for the quality of the feedstock or the natural gas to be used. HECA is waiting for the vendors to tell them what the PM10, PM2,5, VOC, and SO2 will be. It seems to me that clearly prescribed limits on levels of mercury, sulfur, lead and other know contaminates would contribute to making HECA a cleaner gasifying factory. Keeping low-grade or adulterated levels of coke, coal and natural gas out of the feedstock will reduce pollution emissions. A system for documenting and testing for compliance should be part of the PDOC and CEC plan.

Record of Telephone Comment

Commenter: Pat Newman in Wasco
Date: 4/3/13

Mr. Newman called the District's Leonard Scandura regarding Mr. Tom Frantz's concerns (made at the 4/2/13 public hearing) about the coal spilling onto the railroad tracks near the Wasco coal transfer facility. Mr. Newman said he used to farm next to the rail spur identifed as a problem area and did not see coal on the ground or see a coal dust problem. He was not at the 4/2/13 public hearing, to make his comments then. He also the District is doing a good job.

Record of Telephone Comment

Commenter: Walter Benz, a Kern County resident
Date: 4/3/13 at 2 PM

Mr. Benz is in favor of the HECA facility being built as it will create jobs. He does not believe it will result in environmental issues. He also indicated that those opposed to the project are against a property owner using their property as they want to.

Homero Ramirez

From: Leonard Scandura
Sent: Thursday, April 04, 2013 12:07 PM
To: Homero Ramirez
Subject: HECA verbal comment - 44/13 9:10 am - Chris Romanini

Leonard Scandura called Chris Romanini to advise her of the availability of the ERC information on our website (info that was requested by Mark Romanini) at the public hearing. LS emailed her the weblink.

Chris Romanini made the following comments:

1) Did not like the attitude of the District staff at the 4/2/13 public hearing. They did not ask the public what they felt about the project. (LS reminded her that there was a long period of public comments.)

2) Did not feel response was honest regarding any influence Ray Watson may have had about the project on District staff.

3) EPA advised the District (when they handed off PSD permit to the District?) that there were EJ issues that should be addressed. You did not follow their advice.

4) Agreed with Anna Martinez regarding impact of project on EJ communities. They will be impacted, but have not been advised about the project.

I told Chris Romanini that we would be responding to her comments (and all comments received at the hearing) in writing.

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Leonard Scandura

From: Trudy Douglass <trudydouglass@att.net>
Sent: Thursday, April 04, 2013 1:14 PM
To: Leonard Scandura
Subject: Health risks

Mr. Scandura,
What studies do you use in making your Health Risk Analysis in the PDOC? How currant are they?
Trudy Douglass
834-4889

GREENACTION
for Health & Environmental Justice

April 5, 2013

Dave Warner
Director of Permit Services
San Joaquin Valley APCD

REQUEST FOR NEW PUBLIC HEARING WITH BILINGUAL NOTICE IN THE AFFECTED COMMUNITY ON PROPOSED HYDROGEN ENERGY CALIFORNIA FACILITY, AND REQUEST FOR TRANSLATION OF KEY DOCUMENTS INTO SPANISH

Dear Mr. Warner,

On behalf of our constituents living near the proposed Hydrogen Energy California Facility, we are writing to call on the San Joaquin Valley Air Pollution Control District to hold and properly notice a new public hearing on the District's preliminary Determination of Compliance.

The hearing should be in the affected community, and the notice, hearing, and project documents should be fully translated into Spanish. The hearing should be at a time and place that will allow residents to attend.

The hearing held last week had no public notice in Spanish and none of the permit documents were in Spanish, despite the fact that a large percentage of nearby residents are Latino Spanish-speakers. .

The notice you just issued yesterday in Spanish regarding an extension of the public comment period came after the public hearing, meaning that the Spanish-speaking Latino community members are being denied the same opportunity for public comment and participation in the process as English speakers.

In addition, we request that you provide to us on behalf of our Spanish-speaking constituents the Spanish language full packet of information about this project.

As this project is proposed near a heavily impacted community of color, the actions of all government agencies involved in the decision-making process are subject to state and federal civil rights laws. It is imperative that all residents are provided a meaningful opportunity to comment and participate in the decision-making process.

We look forward to your response to this request.

Sincerely,

Bradley Angel

Bradley Angel
Executive Director

Greenaction for Health and Environmental Justice
703 Market Street, Suite 501, San Francisco, CA 94103
Phone: (415) 248-5600 Fax: (415) 284-4666
www.greenaction.org

Leonard Scandura

From: msbel322@aol.com
Sent: Sunday, April 07, 2013 11:32 PM
To: Leonard Scandura
Subject: HECA Facility in Kern County

Dear Mr. Scandura,

Residents of Bakersfield and nearby areas are angry about the proposed HECA hydrogen facility near Tupman. **There is absolutely no reason that this plant that will import millions of tons of coal in our county should be built.**

The public has a right to know that this plant will not only threaten our water resources, but it will lead to dirtier air and more health problems to the residents of Kern County. Our air quality is a top priority item. We want to continue improving air quality in the south Central Valley, not reverse the direction in years to come.

There is no way around it: coal is a dirty way to fuel power plants. Coal is a dirty fuel, and there is no justification for using it in the 21st Century. There is no such thing as "clean coal": that is a lie being foisted on the public by companies wanting to make vast sums of money building such plants. Coal pollutes the land, water, air and other vital resources. The pollutants that fall on prime agricultural land near the plant will also affect crops, farmworkers and area residents.

Until very recently (in the last month) no one has thought about putting out notices in Spanish to people who will be affected hugely by the HECA facility. No one really believes that this omission was accidental.

No one has yet determined what will happen to the slag leftover from coal processing. What's the deal here? Why is disposition of the waste not part of this 600-page report? Is it possible that nobody wants the leftover millions of tons of slag in their backyard?

No one I know wants to live downwind from a dirty power plant that is an environmental hazard. No one I know wants to pay for increased health costs for those affected by the HECA plant's existence in Kern County.

There is no good reason to recommend that the HECA plant be built anywhere in Kern County, which has (as you well know) already some of the dirtiest air in the nation.

Sincerely,

Marjorie Bell
Retired teacher/ Bakersfield resident
3419 La Cresta Dr.

Bakersfield, CA 93305-1021

2

recvd 4/9/13

Dave Warner

HECA Neighbors supports Greenaction's call for a new hearing with outreach to Spanish speakers.
RE: Preliminary Determination of Compliance hearing by San Joaquin Valley Air Pollution Control District for Hydrogen Energy California 08 AFT 8A

HECA Neighbors has members and employees of members who are Spanish speaking. These folks have been overlooked by the SJVAPCD with a hearing for the Determination of Compliance that did not involve the Spanish speaking community. Environmental justice communities are more vulnerable to pollution risks than the average population. With significant new emissions from HECA going into air declared by the American Lung Assoc. to be the most polluted in the nation and with our extreme nonattainment, public participation by people working so closely to HECA is important. Just an extension of the public comment period is not enough of an outreach to involve them in the process. Months ago Spanish speaking field workers wrote and asked what will be in the air they breathe. We understand these workers want an explanation as to how the purchased offsets are protecting them from the tons of new emissions. You need to help them ask those questions and others and get truthful answers they understand.

On behalf of the Spanish speaking people so impacted, HECA Neighbors demands a new public hearing that includes outreach to them. Hearing should be properly noticed in Spanish in communities most impacted, especially Buttonwillow, Tupman, Wasco (unloading terminal), and Shafter (transportation avenue). Hearing should be held in the general area (Buttonwillow has a senior center and a school). And the public comment period should be extended until a reasonable period after the hearing.

Appreciate your timely action.

Chris Romanini
HECA Neighbors

Leonard Scandura

From: Trudy Douglass <trudydouglass@att.net>
Sent: Friday, April 12, 2013 11:45 AM
To: Leonard Scandura; rworl@energy.state.ca.us; roberts.blake@energy.ca.gov
Subject: SJVAPCD and HECA

To:CEC and SJAPCD regarding HECA

From: Trudy Douglass

DOC 08-AFC-8A

April 10, 2013

On April 2, Mr. Warner of the San Joaquin Valley Air Pollution Control District said that the board's decision on the Preliminary Determination of Compliance was all about the air. However, many members of the district's staff have made different statements: "We need electricity.", "It is good for our finances.", and "It's good for the economy." Have they forgotten that intent of their mission is to do good for the AIR and the PEOPLE **not** the corporation? I cannot believe that adding more than 80 tons of PM2.5 a year to the valley is going to be good for our children's air.

Do we really need more electricity? It is my understanding that Kern County's power grid is almost at capacity from what we produce now. PG&E is going to build a switching station and make other modifications for connecting HECA to the grid. The costs of alterations like these are usually passed on to the consumers, so we will be paying more for our electricity. Is it good for our finances? It looks like Kern County residents will be fined for generating too much waste because of the 70 truck loads of slag HECA will send to our dumps each day. In addition, we will pay for the roads destroyed by the high volume of HECA truck traffic. The wealth of this factory will come at a high cost to both our health and our pocketbooks.

On that same night Mr. Warner said that environmentalists love the gasification/ sequestration/chemical factory process. He had none of them present to tell us of the benefits to the valley of this project. The fact is that New Jersey, Australia, Ireland, and Abu Dhabi have all said no to this industrial monstrosity. Kern County is to be the world's lab rat.

If the district really cared about the air, they would not have disregarded rules 2201 and 2410. These rules: "require an examination of the impacts of the proposed project on the ambient air quality." In the PDOC, the district chose to look at the effect of the valley air quality **on** the HECA project site. These rules also go on to state that the historic or significant actual emissions of the valley are to be used in district formulas and that they can do their calculations on as little as two years of data. Also monitors with higher emission levels give the most conservative results. The district used a number of different monitors for different emissions but they chose to ignore in the highest concentrations of these emissions recorded in Arvin, Bakersfield, and Edison.

The goal is have: "No net increase in emissions above specified thresholds from new Stationary Sources of all non-attainment pollutants and their precursors." 2201, 1.2 SJVAPCD have failed to do this. PM2.5 is in non-attainment and no amount of mitigation will make the over 80 tons of it a year safe for the valley residents to breath.

Last, shame on the SJVAPCD staff and HECA, how can they use the "speculation" that the height of the stack will carry the poisonous emissions out of our area as a selling point for building this filthy factory. It is indefensible that they would be proud of this. In order to fulfill rule 2410 and to protect the people who live in the valley, they need to project the worst case scenario for the HECA factory. This is that all the emissions stay in the valley for the next 30 years. Have they no respect or regard for the people they are supposed to protect? Isn't it their agency's responsibility to prevent deterioration to air quality?

Leonard Scandura

From: Betty Foley <jlfoley@pacbell.net>
Sent: Friday, April 12, 2013 12:32 PM
To: robert.worl@energy.ca.gov; blake.roberts@energy.ca.gov; Leonard Scandura
Subject: energy factory

Please do not build the energy factory in or near Bakersfield. Our air is so-o-o bad.
There must be a better place for it.
Thank you for considering my request.
Jill Foley

1

Homero Ramirez

From:	Kelly, Shaheerah <Kelly.Shaheerah@epa.gov>
Sent:	Friday, April 12, 2013 4:48 PM
To:	Dave Warner
Cc:	Rios, Gerardo; GLASS, GEOFFREY; Holladay, Cleveland; Rivera, Shirley; Yannayon, Laura; Leonard Scandura; Homero Ramirez
Subject:	EPA Comment Letter
Attachments:	EPA Comments re HECA PDOC 04112013.pdf

Dave,

EPA issued the attached comment letter regarding the Preliminary Determination of Compliance for the Hydrogen Energy California (HECA) project.

****

Shaheerah Kelly
U.S. Environmental Protection Agency, Region 9
Permits Office, Air Division
San Francisco, CA 94105
Phone: 415-947-4156
Fax: 415-947-3579
Email: kelly.shaheerah@epa.gov

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

April 11, 2013

David Warner, Director of Permit Services
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, California 93308

RE: Hydrogen Energy California, LLC Preliminary Determination of Compliance

Dear Mr. Warner:

This letter is in regard to the Preliminary Determination of Compliance (PDOC) issued by the San Joaquin Valley Air Pollution Control District (District) to Hydrogen Energy California, LLC for the construction of a proposed 300 megawatt integrated gasification combined cycle (IGCC) power generation facility and integrated fertilizer manufacturing complex in western Kern County.

EPA appreciates the opportunity to comment on the PDOC. Based on our review of the PDOC, we have several comments regarding the Best Available Control Technology (BACT) requirements and air quality analysis performed for the project. We provide these comments to help ensure that the project meets federal Clean Air Act requirements, that the permit will provide necessary information so that the basis for the permit decision is transparent and readily accessible to the public, and that the record provides adequate support for the decision. Our comments are attached to this document.

We look forward to working with you and your staff to address these comments. If you have any questions, please contact Shaheerah Kelly, of my staff, at (415) 947-4156 or kelly.shaheerah@epa.gov.

Sincerely,

Gerardo C. Rios
Chief, Permits Office
Air Division

Enclosure: EPA Comments on the Hydrogen Energy California, LLC Preliminary Determination of Compliance

cc: Michael J. Tollstrup, California Air Resources Board
Marisa Mascaro, Hydrogen Energy California, LLC
Julie Mitchell, URS Corporation
Leonard Scandura, San Joaquin Valley Air Pollution Control District
Homero Ramirez, San Joaquin Valley Air Pollution Control District

EPA Comments on the Hydrogen Energy California, LLC Preliminary Determination of Compliance

Greenhouse Gas (GHG) Requirements

1. The PDOC contains two limits that apply to the turbine: a 90% capture efficiency of carbon from syngas when burning hydrogen rich fuel and a 400 lb/MW-hr performance standard. The 400 lb/MW-hr standard is not included in the top-down Best Available Control Technology (BACT) analysis but is included in the pre-analysis discussion as "one of the various requirements to demonstrate with the GHG BACT." The BACT analysis must explain more clearly whether this limit is used to demonstrate BACT for the turbine generator.

2. The PDOC requires that the facility demonstrate compliance with a 400 lb/MW-hr standard which has no averaging period associated with it. Because the standard appears to have been developed by dividing annual CO_2 potential-to-emit (PTE) by annual potential energy output (see Table 2 of appendix I), it is not clear whether the applicant could comply with it on a monthly basis. Also, since there is no averaging period, it is not clear how the applicant would actually demonstrate compliance. The prmit must specify how the permittee will demonstrate compliance with the 400 lb/MW-hr limit and the engineering evaluation must demonstrate whether compliance with this limit will demonstrate compliance with the 90% capture efficiency requirement.

3. The permit must specify whether the 400 lb/MW-hr standard in permit condition 86 for the power generation system (S-7616-26-0) is in terms of CO_2 or CO_2e.

4. The GHG BACT analysis does not contain a discussion regarding what kind of output-based limit in lb/MW-hr would be equivalent to 90% carbon removal from the syngas stream and the limits on CO_2 venting and natural gas combustion. EPA policy is to establish output-based emission limits whenever possible. The permit must establish and the engineering evaluation must justify an output based limit equivalent to the 90% carbon removal requirement and limitations on venting.

5. There are several deficiencies related to monitoring the capture efficiency requirement:

    - The 90% capture efficiency of carbon from syngas has no averaging period.
    - Although the permit requires the permittee to demonstrate compliance with this standard by monthly laboratory tests of CO_2, carbon monoxide (CO), and methane (CH_4) before and after the acid gas removal system, there is no test method, time period, or sample volume associated with the tests.
    - There is no parametric monitoring required for the acid gas removal system (e.g. flow rate, temperature, pH) or even a requirement to monitor whether the acid gas removal system is actually operating.

    The permit must define an averaging period for the 90% carbon capture efficiency establish adequate monitoring requirements for the acid gas removal system. EPA believes that a continuous emission monitoring method for carbon dioxide (CO_2) and a continuous parametric

monitoring system for the acid gas removal system are warranted for this project given the magnitude of GHG emissions.

6. Permit condition 87 for the power generation system (S-7616-26-0) sets a facility-wide limit of 595,917 tons CO_2e per calendar year. Although emissions of CO_2e are calculated monthly, the limit is defined on a calendar year basis, contradicting EPA guidance recommending shorter term limits or at least limits in terms of tons per rolling continuous 12-month period. The permit does not explain how facility-wide CO_2e should be calculated. The permit must include a demonstration methodology for the facility-wide limit and either redefine the limit as a rolling 12-month total or explain in the engineering evaluation why a rolling continuous 12-month total is not necessary.

7. EPA is currently proposing to change 100-year global warming potentials (GWPs). To avoid difficulty complying with CO_2e limits in the future, when emission limits are expressed in terms of CO_2e, the GWPs used should be specified in either the permit or engineering evaluation for the permit.

Criteria Pollutant Requirements

1. The gasification system (S-7616-21-0) includes a general description of the syngas cleanup system which consists of a syngas scrubbing system, sour shift/low temperature gas cooling system, sour water treatment system, and rectisol acid gas removal unit. The permit must contain a condition(s) that specifically requires operation of the syngas cleanup system to minimize emissions of volatile organic compounds, sulfur compounds, and mercury.

2. Permit conditions 41 through 45 for the auxiliary boiler (S-7616-25-0) authorize the use of "equivalent equipment" or "alternate equipment" upon approval by the District. The terms "equivalent equipment" and "alternate equipment" are used interchangeably and are not defined in the permit. The permit must define these terms and require that the facility keep a log of each time the equipment is replaced.

3. Although the Preliminary Determination of Compliance (PDOC) contains permit conditions for the combustion of hydrogen-rich fuel (primary fuel) and natural gas (back-up fuel) in the turbine, it does not address what which limits apply when these fuels are combusted together in the turbine (S-7616-26-0). The permit and/or engineering evaluation should address what limits apply when these fuels are combusted together.

4. 40 CFR 52.21, which is incorporated by reference in the District's Rule 2410, requires that BACT not exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. The BACT analysis did not address or include a comparison of these standards to the proposed BACT determinations. In the future, we recommend that, where applicable, that a comparison of the applicable standard under 40 CFR parts 60 and 61 to the proposed BACT determination(s) be included in the District's BACT analyses for PSD projects.

Air Quality Analysis

1. It is our understanding, based on the Executive Summary in the PDOC, that certain areas immediately surrounding the source will be inaccessible to members of the public due to a

physical fence, and that therefore those areas were not included in the air quality modeling analysis. This approach is generally consistent with EPA regulations and guidance concerning "ambient air" in the context of required air quality impact analyses under PSD. EPA requests that an enforceable permit condition be added to assure construction and maintenance of the fence for the duration of the facility operations.

2. The nitrogen dioxide/nitrogen oxide (NO_2/NOx) in-stack ratios (ISRs) used in the Tier 3 NO_2 modeling for the nearby sources and proposed project units are presented in Appendix K, Tables 6-6 and 6-7, respectively. We understand that the San Joaquin Valley Air Pollution Control District has a draft guidance document that was relied upon for several of the ISRs, as well as consideration of other sources' ratios. Please ensure that supporting information is available to justify the selected ISRs. Additionally, we recommend forwarding the collected ISR information to Chris Owen of the EPA (owen.chris@epa.gov) for inclusion in the EPA database – http://www.epa.gov/ttn/scram/no2_isr_database.htm.

3. In Section 6.5.2 of Appendix K, the District describes the following, with regards to the significant impact area (SIA):

   For analyzing the representativeness of the meteorological dataset, the area of interest includes:
   - the SIA where screening modeling predicts the project's pollutant impact to be greater than the SILs, and
   - the sources and receptors used in the modeling.

   We note that the SIA is not specifically referenced in the PDOC. Please include a reference in Appendix K that the significant impact area is 13 (thirteen) kilometers.

4. Please include, in the engineering evaluation for the permit, a table that presents and summarizes the specific stack parameters (e.g., stack height, temperature, exit velocity, stack diameter) for those equipment and processes in the air quality modeling analyses as described in Appendix K. For example, the table may be similar to Table 3 of Appendix I in the May 2012 PSD permit application update. Additionally, the permit should contain a condition that requires project construction and operation in accordance with the permit application and plans submitted with the permit application, the District's PSD regulations, and other terms and conditions set forth in the permit.

5. We would like to clarify for the record what we considered in approving HECA's approach for combining monitored and modeled concentrations. In June 2010, EPA issued a guidance document: *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program* (USEPA, 2010c). In preparation for performing the 1-hour NO_2 modeling analysis described in the guidance document, HECA submitted a modeling protocol titled *"Modeling Protocol for Parameter Selection Specific to the 1-Hour NO2 NAAQS Regional Modeling for the Hydrogen Energy California (HECA) Project"* on January 20, 2011. In order to estimate total NO_2 concentrations for comparison with the new 1-hour NO_2 standard, HECA proposed in the protocol to use the temporal pairing of modeled concentrations with monitored concentrations.

For this project, HECA proposed that the air dispersion model, AERMOD, would add the hourly modeled NO_2 concentrations based on 2006-2010 meteorological data to the concurrent (2006-2010) hourly NO_2 background data from the most representative monitor and determine the design value, the 98th percentile (eighth-highest) daily maximum 1-hour NO_2 concentration at each receptor averaged across the five modeled year for comparison with the 1-hour standard. Before and after the protocol was submitted, there had been ongoing discussions between HECA, Region 9, and OAQPS for several months during which HECA presented justification for using the temporal pairing method they proposed. Based on the rationale provided by HECA, EPA Region 9 approved the modeling protocol on March 11, 2011.

The following discussion provides a summary of the grounds for approving the protocol. HECA proposed to use the Shafter-Walker NO_2 data as the most representative monitoring data available in the area of the project. However, the hourly monitoring concentration was greater than or equal to the new NO_2 standard of 188 ug/m3 twice during the 5-year data set. Because the standard is based on the 98th percentile (eighth-highest) daily maximum 1-hour concentration, more than one hourly average concentration above the standard on the same day will only result in one concentration greater than the standard for that day. This allows a monitor or model receptor to have up to 7 days with one or more hours greater than the standard within each day on an annual basis and still be considered in compliance with the NAAQS. For these monitoring data, the applicant showed that the "first tier" assumption (a term defined in the June 2010 USEPA guidance document) of adding the overall highest hourly background NO_2 concentration to the model results was overly conservative and would result in numerous predicted violations that were not valid. The June, 2010 guidance provided that additional refinements to this "first tier approach" based on some level of temporal pairing of modeled and monitored values may be considered on a case-by-case basis, with adequate justification and documentation.

In addition, during the evaluation period after the submittal of the protocol, EPA issued the March 1, 2011, guidance document: *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (USEPA, 2011). This guidance document, provided further clarification on uncertainties raised since the earlier June 2010 modeling guidance document. The new guidance, while not generally recommending the use of hour-by-hour temporal pairing, did provide that it could be justified if there was a demonstration of the overall conservatism of the cumulative assessment based on the combination of modeled and monitored impacts (p. 21). An exploration of the modeled inventory used by the applicant shows that it clearly represents the majority of the emissions that could potentially contribute to the cumulative impact assessment. There are 371 sources in the nearby source inventory that were included in the modeling. The applicant also made a good case that the conservativeness of the monitor more than made up for any other shortcomings.

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225-0287

IN REPLY REFER TO:

N3615 (2350)

April 17, 2013

David Warner, Director of Permit Services
San Joaquin Valley Unified Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

Re: Project #S-1121903

Dear Mr. Warner:

Hydrogen Energy California (HECA) is proposing to construct and operate an Integrated Gasification Combined-Cycle combustion turbine project with 300 MW nominal capacity. The project would be located 120 km west of Sequoia and Kings Canyon National Parks, a Class I area administered by the National Park Service. The project is subject to both Nonattainment and Prevention of Significant Deterioration regulations for nitrogen oxides (NO_X). Our comments are directed to the NO_X limit proposed as Best Available Control Technology (BACT) by the San Joaquin Valley Unified Air Pollution Control District (SJUAPCD).

SJUAPCD has proposed that:

> BACT for NOx emissions from this combustion turbine generator is the use of selective catalytic reduction (SCR) that achieves 2.5 ppmvd-NOx @ 15% O2 (1-hour average), except during startup/shutdown when firing on hydrogen-rich fuel. When firing on the backup natural gas, BACT is the use of SCR that achieves 4.0 ppmvd-NOx @ 15% O2 (3-hour rolling average), except during startup/shutdown.

However, permits for combustion turbines with a more-stringent NO_X limits have been issued, and this information necessarily informs the BACT analysis. For example, a permit application (attached) submitted to the State of Washington for the Gray's Harbor Energy project included Table 3 which contains three facilities[1] with a 2.0 ppm limit averaged over one hour, which is

[1] Applied Energy, Chouteau Power, King Power

more stringent than the proposed 2.5 ppm limit (averaged over one hour) in this case. We are also enclosing a permit issued to Dominion Energy in Virginia which contains a 2.0 ppm limit averaged over one hour. While we understand that the examples cited are for gas-fired combined-cycle turbines, SJUAPCD must show that HECA cannot achieve the same level of performance when burning the hydrogen-rich fuel.

It is not possible from the information provided to determine if the proposed limits represent the vendor guarantees cited by SJUAPCD in the BACT analysis:

> The applicant has provided vendor guarantees that the SCR system reduces NOx emissions from the HRSG stack gases by up to 92 percent when firing hydrogen-rich fuel, and up to 94 percent when firing natural gas.

SJUAPCD has redacted the information necessary to calculate the proposed emission limits.[2] Therefore, neither we nor the public can verify that these limits represent the proper consideration of the cited vendor guarantees. In the absence of such a verifiable demonstration, the BACT information available indicates a limit of 2.0 ppm (over a one-hour average).

Thank you for the opportunity to comment on the HECA permit application. For further information regarding our comments, please contact Don Shepherd at (303) 969-2075.

Sincerely,

Susan Johnson
Chief, Policy, Planning, and Permit Review Branch

Enclosure

[2] According to SJUAPCD, "The removed sections in this page contain information describing the uncontrolled emissions for the combustion turbine generator that has been designated confidential information per the applicant's request, and such information will be kept separate from public record."

bcc:
PWR: Tonnie Cummings, Judy Rocchio
SEKI: Annie Esperanza
ARD: Carol McCoy
ARD-DEN: Permit Review Group, Reading and Project File
ARD-DEN: DShepherd:ds:3/25/13:x2075:HECA PSD.Ltr.docx

Invenergy

April 6, 2012

State of Washington
Energy Facility Site Evaluation Council
Attention: Mr. James Luce, Chair
925 Plum Street SE, Building 4
Olympia, Washington 98504-3172

RE: Grays Harbor Energy Center
Units 3 & 4
Request to Extend the Notice of Construction and Prevention of Significant Deterioration Permit

Dear Chair Luce:

Grays Harbor Energy LLC and Grays Harbor Energy II LLC (collectively Grays Harbor Energy), the holders of the Site Certification Agreement (SCA) for the Grays Harbor Energy Center (referred to as the Project), request that the requirement to begin construction under the Notice of Construction and Prevention of Significant Deterioration (NOC/PSD) permit issued for Units 3 and 4 by the Energy Facility Site Evaluation Council (EFSEC) and the U.S. Environmental Protection Agency (EPA) be extended for an additional 18 months. The request includes the following:

- Background information, including an explanation of why the extension is needed,
- A reevaluation of Best Available Control Technology (BACT) for criteria pollutants (Attachment 1), and
- An evaluation of greenhouse gas (GHG) BACT (Attachment 2).

Background

Grays Harbor Energy proposes to add two combined-cycle combustion turbine generators (Units 3 and 4) and one steam turbine generator, in a two-on-one configuration, to the existing Units 1 and 2 at the Grays Harbor Energy Center electrical power generating facility. The addition will increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MW. Units 3 and 4 would be located entirely within the boundary of the current SCA. As with Units 1 and 2, Units 3 and 4 would be fueled by natural gas, and no backup fuel source is proposed for electrical generation (the emergency back-up generator and fire pump are diesel fueled). The fuel for Units 3 and 4 would be supplied from the natural gas pipeline installed for the existing facility.

A permit application for the Project was submitted Grays Harbor Energy on October 30, 2009, and the final permit was signed by EPA and EFSEC. Condition 23 of the permit specifies that

the permit "shall become invalid" if construction has not commenced within 18 months after receipt of final approval. However, "EPA and EFSEC may extend the 18-month period upon satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2)." Grays Harbor Energy is submitting this extension request because it does not expect to begin construction prior to 18 months after the permit was issued.

As an independent power producer, Grays Harbor Energy does not plan to commence construction of the Project absent a long-term power purchase agreement from a major utility company. The current economic downturn has reduced the demand for new power generation in the region. As a result, Grays Harbor Energy has been unable to secure the power purchase agreements necessary to begin construction of the Project. Grays Harbor Energy is confident that market conditions will eventually improve to justify construction of Units 3 & 4.

Criteria Pollutant BACT Reevaluation

The NOC/PSD permit issued for the Units 3 & 4 was based on the criteria pollutant BACT analysis provided in the permit application submitted in October 2009 and during the ensuing permitting process. A reevaluation of BACT that considers emission limits and control alternatives applied to similar facilities permitted since the Units 3 & 4 NOC/PSD permit was issued is included as Attachment 1 to this letter.

Greenhouse Gas BACT Evaluation

On May 13, 2010, EPA promulgated the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing Greenhouse Gas (GHG) emissions from stationary sources, by "tailoring" the major source applicability thresholds under the PSD and Title V air operating permit programs and providing a phased implementation for GHG permitting requirements. After January 2, 2011, the date the Tailoring Rule went into effect, new sources or modifications of existing sources expected to increase total greenhouse gas emission rates by 75,000 tons per year (tpy) or more, on a carbon dioxide equivalent (CO_2e) basis, and whose emissions exceed the PSD threshold for one or more criteria pollutants, were subject to PSD review for GHGs. Because there is no ambient standard or increment for GHGs, the only PSD requirement that applies to GHGs is that BACT must be evaluated for potential reduction of GHG emissions from the proposed project.

At the time that the NOC/PSD permit was signed, the Project was not subject to the requirements of the Tailoring Rule and thus, the permitting process did not address GHG BACT. Washington Administrative Code (WAC) 173-400-720(5)(b)(i)(B) states that a PSD permit extension request must contain "[a]n evaluation of BACT … for all pollutants subject to the approval conditions in the PSD permit." Because GHGs are not subject to any approval conditions in the permit, this permit extension request perhaps need not include a GHG BACT analysis. However, in the spirit of adhering to the EPA's Tailoring Rule and to ensure that a permit extension can be issued in a timely manner, Grays Harbor Energy is voluntarily and

proactively providing a GHG BACT analysis. The GHG BACT analysis is included as Attachment 2 to this letter.

Conclusions

The reevaluation of BACT for criteria pollutants confirms that 1) emission limits and emission control technologies deemed BACT in the 2010 NOC/PSD permit are consistent with recent BACT determinations, and 2) no significant state-of-the-art advancement has occurred in control technologies for combustion turbine-based combined-cycle power generating facilities since the 2010 NOC/PSD permit was issued.

The BACT analysis for GHGs was developed for all equipment with the potential to emit GHGs using EPA's recommended "top-down" approach. The design for Units 3 & 4, as permitted in the 2010 NOC/PSD, currently represents the Best Available Control Technology for GHG. As appropriate, numeric GHG emission limits, output-based standards, or work practices are provided for each emission unit.

Thank you for your consideration of this permit extension request. If you have any questions, please contact Tom Metzger at 720.283.4694.

Sincerely,

Grays Harbor Energy LLC
Grays Harbor Energy II LLC

Thomas Metzger
Senior Development Manager

Enclosures

cc: Karen McGaffey, Perkins Coie
Eric Hansen, ENVIRON
Richard Biederman, Invenergy LLC
Thomas Metzger, Invenergy LLC

Combined-Cycle Combustion Turbine Project

Best Available Control Technology Analysis

Grays Harbor Energy Center,
Units 3 and 4
Satsop, Washington

Prepared for:
Grays Harbor Energy, LLC and Grays Harbor Energy II, LLC
Satsop, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
April 2012

Project Number:
29-22706D

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1 Introduction

Grays Harbor Energy, LLC and Grays Harbor Energy II LLC (collectively GHE) proposes to construct and operate two combined-cycle combustion turbine generators (Units 3 and 4), and one steam turbine generator at the existing Grays Harbor Energy Center (GHEC) electrical power generating facility. The existing natural gas pipeline system would provide fuel to the new units, which would increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MWe.

1.1 Background

A permit application for the Project was submitted by GHE on October 30, 2009, and the final Notice of Construction and Prevention of Significant Deterioration (PSD/NOC) permit was signed by the U.S. Environmental Protection Agency (EPA) and the Energy Facility Site Evaluation Council (EFSEC). The BACT determination reflected in the PSD permit issued for the Project was based on information provided in the October 2009 permit application and during the ensuing permitting process. Condition 23 of the PSD permit specifies that the permit "shall become invalid" if construction has not commenced within 18 months after receipt of final approval. However, "EPA and EFSEC may extend the 18-month period upon satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2)." WAC 173-400-730(5)(b)(i)(B) requires that a permit extension request include a reevaluation of BACT. This document provides such a reevaluation that considers emission limits and control alternatives imposed on similar facilities that were permitted since the PSD permit was issued

1.2 Project Information

The proposed addition to the existing electric power generating facility would be comprised of the following major pieces of equipment:

- Two Power Generation Units (PGUs), each consisting of a Combustion Turbine Generator (CTG) and an associated Heat Recovery Steam Generator (HRSG) with Duct Burning capability,
- One Steam Turbine Generator (STG),
- One Ten-Cell Cooling Tower,
- One Auxiliary Boiler,
- One Diesel-Powered Back-Up Generator; and
- One Diesel-Powered Emergency Fire Pump.

Of these, only the PGUs, Auxiliary Boiler, Cooling Tower, Diesel-Powered Back-Up Generator, and Diesel-Powered Emergency Fire Pump are expected to emit air pollutants for which BACT must be evaluated.

1.3 Methodology

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was conducted. The search included all entries made after January 2007 for combined-cycle combustion turbines (CCCTs) greater than 25 MWe, auxiliary boilers, diesel-powered emergency generators and fire pumps, and cooling towers. This search was refined using the following criteria:

- Eliminating sources operated in a significantly different manner (e.g., firing fuels other than natural gas, co-firing other fuels with natural gas, simple cycle as opposed to combined cycle, and combined cycle units that do not have duct burning capability).

- Eliminating permits issued before January 2007 from the RBLC database search. A detailed search of these databases was conducted prior to the permit application in October 2009. The search was extended back to January 2007 to capture any emission units permitted, but not added to the database, prior to submittal of the permit application.

2 Power Generation Unit

The CCCTs and the duct burners associated with HRSGs that comprise the PGUs would combust pipeline natural gas exclusively. The PGUs would emit the following criteria pollutants: NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, VOCs, and sulfuric acid (H_2SO_4), as well as toxic air pollutants (TAPs). A summary of the emission limits in the permit is provided in Table 1, and a listing of similar permitted emission units found in the RBLC database is provided in Table 2.

2.1 Oxides of Nitrogen (NO_X) Emissions

In the 2010 GHEC permit, lean, premixed dry-low-NO_X (DLN) turbine burners and low-NO_X duct burners with Selective Catalytic Reduction (SCR) represented BACT for control of NO_X from CCCTs with supplemental duct firing. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 2.0 parts per million (ppm) averaged over three hours. The updated analysis indicates that SCR in combination with DLN combustion remains BACT for similar units, and that there are no more stringent permit limits (see Table 3).

2.2 Carbon Monoxide (CO) Emissions

The 2010 GHEC permit indicated that an oxidation catalyst and good combustion practices represent BACT for control of CO from CCCTs with supplemental duct firing. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 2.0 ppm, averaged over three hours. This updated BACT Analysis indicates that this technology remains BACT for similar units, and that no more stringent permit limits (see Table 4).

2.3 Sulfur Dioxide (SO_2) Emissions

The sulfur content of the fuel determines SO_2 emission rates. The sulfur content of pipeline natural gas is monitored, and, to some extent, controlled by the gas supplier. EFSEC and EPA concurred with the BACT determination for control of SO_2. Virtually all permits for CCCTs in the RBLC database indicate that use of low-sulfur fuel or pipeline quality natural gas is BACT (see Table 5), indicating that BACT for SO_2 emitted by CCCTs has not changed since permit was issued in 2010. Because the sulfur content of natural gas varies from one region to another, it is not appropriate to compare SO_2 permit limits issued to sources in different regions.

2.4 Particulate Matter (PM_{10} and $PM_{2.5}$) Emissions

Given that proper combustion is maintained, PM_{10} and $PM_{2.5}$ emissions are determined by the amounts of sulfur, nitrogen, and ash present in a fuel. While all natural gas contains negligible amounts of these constituents, the content is monitored and, to some extent, controlled by the gas supplier. The 2010 permit determined that the use of natural gas and proper combustion is BACT for PM_{10} and $PM_{2.5}$ emissions from a combined cycle gas turbine with duct firing. EFSEC and EPA concurred, and established permit limits for PM_{10} of 0.0078 lb/MMBtu with duct burners and 0.0072 lb/MMBtu without duct burning. The permit limit for $PM_{2.5}$ was established at 0.0020 lb/MMBtu with or without duct burning.

PM_{10} and $PM_{2.5}$ permit limits for similar sources vary (see Table 6), with much of the variability likely due to differences in the properties of the gas available in that region, and the turbine design. Virtually all permits in the RBLC database indicate that proper combustion of pipeline natural gas remains BACT for PM_{10} and $PM_{2.5}$.

2.5 Volatile Organic Compound (VOC) Emissions

VOC emissions are generally the result of incomplete combustion. The 2010 permit determined that DLN burners with an oxidation catalyst represent BACT for control of VOC emissions. EFSEC and EPA concurred with this BACT determination as well as the proposed permit limit of 1 ppm averaged over one hour. Virtually all permits in the RBLC database indicate that proper combustion of natural gas and an oxidation catalyst continue to be BACT (see Table 7).

2.6 Sulfuric Acid Mist (H_2SO_4) Emissions

Like SO_2 emissions, H_2SO_4 emissions are strongly related to fuel sulfur content. The 2010 permit determined that the use of natural gas and a permit limit of 3.66 lb/hr in a 12-month rolling average represented BACT. EFSEC and EPA concurred with this BACT determination. The updated review of the RBLC database indicates that the use of low-sulfur fuel or pipeline quality natural gas remains BACT for H_2SO_4 emissions from CCCTs (see Table 8).

2.7 Toxic Air Pollutant (TAP) Emissions

Analysis of BACT for toxic air pollutants (T-BACT) is required under Washington Administration Code (WAC) 173-460-040(4) for sources with a potential increase in emissions of regulated TAPs. The vast majority of TAP emissions from natural gas combustion are VOCs. For the 2010 permit, proper combustion and use of an oxidation catalyst represented T-BACT, and nothing currently in the RBLC suggests that T-BACT has changed since. Table 9 compares ammonia (NH_3) emission limits from the RBLC database with those in the GHEC permit as an example.

2.8 Summary

This BACT reevaluation demonstrates that no significant state-of-the-art advancement in BACT for CCCT-based power generating facilities has occurred. The control technologies deemed BACT in the 2010 GHEC permit are consistent with more recent BACT determinations. Where applicable, permit emission limits are also consistent with recent BACT determinations.

3 Auxiliary Boiler

The auxiliary boiler would combust exclusively natural gas and emit the following criteria pollutants: NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, VOCs, and sulfuric acid (H_2SO_4), as well as toxic air pollutants (TAPs). The auxiliary boiler generates steam to allow the steam turbine to start more quickly, which allows the facility to be responsive to changing load demands. It will operate no more than 2,500 hours per year. A summary of the auxiliary boiler emission limits in the permit is provided in Table 10, and a listing of similar permitted emission units found in the RBLC database is provided in Table 11.

3.1 NO_X Emissions

In the 2010 GHEC permit, ultra-low NO_X burners (ULNBs) represented BACT for control of NO_X from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 9.0 parts per million (ppm) averaged over one hour. The permit also limits the NO_X emissions to 0.32 lb/hr, which, when combined with the maximum heat rate (29.3 MMBtu), yields an equivalent emission factor of 0.0109 lb/MMBtu. The updated analysis indicates ULNBs remain BACT for similar units, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.2 CO Emissions

The 2010 GHEC permit indicates that proper burner design and good combustion practices represents BACT for CO emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 50 ppmvd. The permit also limits CO emission to 1.08 lb/hr, which, when combined with the maximum heat rate (29.3 MMBtu), yields an emission factor of 0.0369 lb/MMBtu. The updated analysis indicates no change to that determination, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.3 SO_2 Emissions

Virtually all permits in the RBLC database indicate use of low-sulfur fuel (e.g., pipeline natural gas) is BACT (see Table 12). This represents no change from the BACT determination made for SO_2 emissions from the auxiliary boiler in the 2010 GHEC permit.

3.4 PM_{10} and $PM_{2.5}$ Emissions

The 2010 GHEC permit indicates that burning natural gas represents BACT for PM emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 0.005 lb/MMBtu. The updated analysis indicates no change to that determination, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.5 VOC Emissions

The 2010 GHEC permit indicates that proper burner design represents BACT for VOC emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 0.004 lb/MMBtu. The updated analysis indicates that burner design and good combustion practices represent BACT for VOCs, and that the permit limit is among the most stringent permit limits found in the RBLC database (see Table 12).

3.6 TAP Emissions

As with the PGUs, the vast majority of TAP emissions from natural gas combustion are VOCs. For the 2010 permit, proper combustion represented T-BACT, and nothing currently in the RBLC suggests that T-BACT has changed since.

3.7 Summary

This BACT reevaluation demonstrates that no significant state-of-the-art advancement in BACT for natural gas-fired auxiliary boiler has occurred. The control technologies deemed BACT in the 2010 GHEC permit are consistent with more recent BACT determinations. Where applicable, permit emission limits are also consistent with recent BACT determinations.

4 Emergency Diesel Engines

A diesel-fueled back-up generator will be available to assist with an orderly shutdown of the PGU in the unusual situation that electrical power is not available from the grid during a shutdown. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection if a fire were to occur when grid power is unavailable. Under non-emergency conditions (i.e., for maintenance and testing), the engines will each operate no more than 100 hours per year. The permit requires that the engines meet the applicable standards in 40 CFR Part 60, Subpart IIII. Subpart IIII requires that an emergency generator of the size used at the site complies with an emissions limit of 2.98 g/bhp-hr for NO_x, 2.61 g/bhp-hr for CO and 0.20 g/bhp-hr for PM. Subpart IIII also requires that a firepump engine of the size used at the site complies with the emissions limits of 3.0 g/bhp-hr for NO_x and 0.15 g/bhp-hr for PM. A review of similar emission units (see Tables 13 and 14) in the RBLC database indicates that BACT has not changed since that determination was made. The engines that have a stricter permit limit are much larger than the ones that will be used at the Grays Harbor Energy site.

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5 Cooling Tower

The 2010 GHEC permit requires that drift eliminators capable of achieving a drift loss of 0.0005% or less of the recirculating water flow rate be installed, and that this, combined with a maximum 7-day average total dissolved solids (TDS) cooling water content of 1,800 ppmw, represents BACT for PM_{10} emissions from the cooling tower. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 19.0 lb/day, averaged over 24 hours. The updated analysis indicates that drift eliminators continue to represent BACT (see Tables 15 and 16), and that the permit limits are still among the most stringent found in the RBLC.

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Tables

Table 1: GHEC BACT Limits for Power Generation Units

Pollutant	Averaging Period	Limit[a]
NO_X @ 15% O_2[b]	3-hour rolling average	2.0 ppm
	24-hour rolling average	1,550 lb/day
CO @ 15% O_2[c]	3-hour rolling average	2.0 ppm
SO_2	1-hour average	0.0058 lb/MMBtu
	Rolling annual average	0.0029 lb/MMBtu
PM_{10} (total w/duct firing)	1-hour average	0.0078 lb/MMBtu
PM_{10} (total w/out duct firing)	1-hour average	0.0072 lb/MMBtu
$PM_{2.5}$ (filterable)	1-hour average	0.0020 lb/MMBtu
VOC[d]	1-hour average	1.0 ppm
Sulfuric Acid Mist	12-month rolling average	3.66 lb H_2SO_4/hr
Ammonia @ 15% O_2	24-hour average	5.0 ppm
Opacity	6-minute average	5%

Notes:

a. Mass emission limits are "per turbine".

b. NOX emission limits are relieved during startup and shutdown and replaced with a limit of 175 lb/hr, averaged over the time associated with startup. NOX emissions are limited to 100 lbs per turbine per shutdown event.

c. CO emission limits are relieved during startup and shutdown and replaced with a limit of 100 lb/hr, averaged over the time associated with each startup. CO emissions are limited to 650 lbs per turbine per shutdown event.

d. VOC emission limits are relieved during startup and shutdown and replaced with a limit of 30 lb/hr, averaged over the time associated with each startup. VOC emission are limited to 40 lbs per turbine per shutdown event.

Table 2: Power Generation Unit RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Applied Energy LLC	San Diego, CA	3-20-09	0
Arsenal Hill Power Plant	Caddo, LA	3-20-08	2110 MMBTU/H
Athens Generating Plant	Greene, NY	1-19-07	3100 MMBTU/H
Blythe Energy Project II	Riverside, CA	4-25-07	170 MW
Caithnes Bellport Energy Center	Suffolk, NY	5-10-06	2221 MMBTU/H
Cane Island Power Park	Osceola, FL	9-8-08	1860 MMBTU/H
Carty Plant	Morrow, OR	12-29-10	2866 MMBTU/H
Chouteau Power Plant	Mayes, OK	1-23-09	1882 MMBTU/H
Fairbault Energy Park	Rice, MN	6-5-07	1758 MMBTU/H
Fpl West County Energy Center	Palm Beach, FL	1-10-07	2333 MMBTU/H
Fpl West County Energy Center Unit 3	Palm Beach County, FL	7-30-08	2333 MMBTU/H
Ineos Chocolate Bayou Facility	Brazoria, TX	8-29-06	35 MW
International Station Power Plant	Anchorage, AK	12-20-10	59900 hp ISO
King Power Station	Harris, TX	8-5-2010	1350 MW
Kleen Energy Systems, Llc	Middlesex, CT	2-25-08	2.1 MMCF/H
Langley Gulch Power Plant	Payette, ID	6-25-10	2375.28 MMBTU/H
Lawton Energy Cogen Facility	Comanche, OK	12-12-06	
Live Oaks Power Plant	Glynn, GA	4-8-10	600 MW
Madison Bell Energy Center	Madison, TX	8-18-09	275 MW
Nacogdoches Power Sterne Generating Facility	Nacogdoches, TX	6-5-06	190 MW
Natural Gas-Fired Power Generation Facility	Lamar, TX	6-22-09	250 MW
Ninemile Point Electric Generating Plant	Jefferson, LA	8-16-2011	7146 MMBTU/H
Northern States Power Co. Dba Xcel Energy - Riverside Plant	Ramsey, MN	5-16-06	1885 MMBTU/H
Otay Mesa Energy Center Llc	San Diego, CA	7-22-09	171.7 MW
Pattillo Branch Power Plant	Fannin, TX	6-17-09	350 MW
Pearsall Power Plant	Frio, TX	1-23-09	8.44 MW
Plant Mcdonough Combined Cycle	Cobb, GA	1-7-08	254 MW
Plaquemine Cogeneration Facility	Iberville, LA	7-23-08	2876 MMBTU/H
Progress Bartow Power Plant	Pinellas, FL	1-26-07	1972 MMBTU/H
Pso Southwestern Power Plt	Caddo, OK	2-9-07	
Rocky Mountain Energy Center, Llc	Weld, CO	5-2-06	300 MW

Table 2: Power Generation Unit RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Thomas C. Ferguson Power Plant	Llano, TX	9-1-2011	390 MW

Table 3: PGU NOx Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	SCR and DLN	BACT-PSD	2.0 ppm	3-hr avg
Other BACT Determinations				
Applied Energy LLC	SCR	BACT-PSD	2 ppm	1 hour
Athens Generating Plant	DLN, Natural gas, SCR	LAER	2 ppm	3 hour block average
Blythe Energy Project II	SCR	BACT-PSD	2 ppm	At 15% O2, 3-hr avg
Caithnes Bellport Energy Center	SCR	BACT-PSD	2ppm	
Cane Island Power Park	SCR	BACT-PSD	2 ppm	24-hr
Carty Plant	SCR	BACT-PSD	2 ppm	3-hr rolling
Chouteau Power Plant	SCR AND DLN	BACT-PSD	2 ppm	1-h avg @ 15% O2
FPL West County Energy Center	DLN and SCR	BACT-PSD	2 ppm	24-hr
FPL West County Energy Center Unit 3	DLN and SCR	BACT-PSD	2 ppm	24-hr
King Power Station	DLN burners and SCR	LAER	2 ppm	1-hour average
Langley Gulch Power Plant	SCR, DLN and Good Combustion Practices	BACT-PSD	2 ppm	3-hr rolling / 15% O2
Madison Bell Energy Center	SCR	BACT-PSD	2 ppm	@ 15% O2, 24-hr rolling average
Natural Gas-Fired Power Generation Facility	SCR	BACT-PSD	2 ppm	@ 15% O2, 24-hr rolling average
Otay Mesa Energy Center LLC	SCR	Other	2 ppm	
Pattillo Branch Power Plant	SCR	BACT-PSD	2 ppm	@ 15% O2 24-hr rolling average
Thomas C. Ferguson Power Plant	DLN and SCR	BACT-PSD	2 ppm	Rolling 24-hr at 15% Oxygen
Live Oaks Power Plant	SCR and DLN	BACT-PSD	2.5 ppm	3 hr avg
Fairbault Energy Park	DLN and SCR	BACT-PSD	3 ppm	3-hr avg
Rocky Mountain Energy Center	DLN AND SCR	BACT-PSD	3 ppm	Hourly Max
Lawton Energy Cogen Facility	SCR and DLN	BACT-PSD	3.5 ppm	@15% O2
International Station Power Plant	SCR and DLN	BACT-PSD	5 ppm	4-hr avg
PSO Southwestern Power Plant	DLN	BACT-PSD	9 ppm	
Progress Bartow Power Plant	Water Injection	BACT-PSD	15 ppm	30-day basis
Arsenal Hill Power Plant	DLN, Duct Burners and	BACT-PSD	0.007 lb/MMBtu	Max

Table 3: PGU NOx Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
	SCR			
Nacogdoches Power Sterne Generating Facility	SCR and DLN	BACT-PSD	0.070 lb/MMBtu	
Pearsall Power Plant	SCR	BACT-PSD	0.0728 lb/MMBtu	
Plaquemine Cogeneration Facility	DLN and SCR	BACT-PSD	0.083 lb/MMBtu	Hourly maximum
Ineos Chocolate Bayou Facility	DLN and SCR	BACT-PSD	0.096 lb/MMBtu	3-hr avg
Kleen Energy Systems, LLC	SCR and DLN	LAER	15.5 lb/hr	Without duct burner

Table 4: PGU CO Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Oxidation Catalyst	BACT-PSD	2.0 ppm	3-hr avg
Other BACT Determinations				
Plant McDonough Combined Cycle	Oxidation catalyst	BACT-PSD	1.8 ppm	3-hour
Caithnes Bellport Energy Center	Oxidation catalyst	BACT-PSD	2 ppm	
King Power Station	Good combustion practice, oxidation catalyst	BACT-PSD	2 ppm	3-hr rolling average
Langley Gulch Power Plant	Catalytic Oxidation and Good combustion practices	BACT-PSD	2 ppm	3-Hr Rolling / 15% O2
Live Oaks Power Plant	Good combustion practices and catalytic oxidation	BACT-PSD	2 ppm	3-hr average
Pattillo Branch Power Plant	Oxidation catalyst	BACT-PSD	2 ppm	@ 15% O2, 3-hr rolling average
Ninemile Point Electric Generating Plant	Oxidation catalyst and good combustion practices	BACT-PSD	3 ppm	hourly average
Rocky Mountain Energy Center	Oxidation catalyst and good combustion practices	BACT-PSD	3 ppm	
Thomas C. Ferguson Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	4 ppm	Rolling 3-hr at 15% oxygen
Blythe Energy Project II		BACT-PSD	4 ppm	At 15% O2, 3-hr avg
Cane Island Power Park	Good combustion practices	BACT-PSD	6 ppm	12-Month
FPL West County Energy Center Unit 3	Good combustion	BACT-PSD	6 ppm	12-Month
Progress Bartow Power Plant	Good combustion	BACT-PSD	8 ppm	24-hr block
Chouteau Power Plant	Good combustion	BACT-PSD	8 ppm	1-Hr avg
FPL West County Energy Center		BACT-PSD	8 ppm	24-Hr
Fairbault Energy Park	Good combustion	BACT-PSD	9 ppm	3-Hr avg
Northern states Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practices	BACT-PSD	10 ppm	3-hr block
Natural Gas-Fired Power Generation Facility	Good Combustion Practices	BACT-PSD	15 ppm	@ 15% O2, 24-hr rolling average
Lawton Energy Cogen Facility	Good combustion practices	BACT-PSD	16.38 ppm	@15% O2
Madison Bell Energy Center	Good combustion practices	BACT-PSD	17.5 ppm	@ 15% O2, 1-hr rolling average
PSO Southwestern Power Plant	Combustion Control	BACT-PSD	25 ppm	@15% O2
Kleen Energy Systems, LLC	CO Catalyst	BACT-PSD	4.3 lb/hr	W/out Duct Burner

Table 4: PGU CO Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Arsenal Hill Power Plant	Proper operating practices	BACT-PSD	0.0679 lb/MMBtu	Max
Plaquemine Cogeneration Facility	Good combustion practices	BACT-PSD	0.0739 lb/MMBtu	Hourly maximum
Nacogdoches Power Sterne Generating Facility	Good combustion practices	BACT-PSD	0.169 lb/MMBtu	
Pearsall Power Plant	Oxidation catalyst	BACT-PSD	0.26 lb/MMBtu	
Ineos Chocolate Bayou Facility	Good combustion practices	BACT-PSD	0.560 lb/MMBtu	

Table 5: PGU SO2 Control Technologies Search Results				
Facility	**Control Description**	**Basis**	**Permit Limit**	**Limit Notes**
Current BACT Limits for GHE				
Grays Harbor Energy Project	Low sulfur natural gas	BACT-PSD	0.0058 lb/MMBtu	1-hr average
Other BACT Determinations				
Chouteau Power Plant	Natural gas fuel	N/A	0.0006 lb/MMBtu	3-hr average
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0011 lb/MMBtu	
Arsenal Hill Power Plant	Low sulfur natural gas	BACT-PSD	0.0057 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility	Pipeline natural gas	BACT-PSD	0.0110 lb/MMBtu	
Plaquemine Cogeneration Facility	Low sulfur fuels	BACT-PSD	0.0142 lb/MMBtu	Hourly maximum
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0203 lb/MMBtu	1-hr
INEOS Chocolate Bayou Facility	Low sulfur natural gas	BACT-PSD	0.1060 lb/MMBtu	
Cane Island Power Park	Fuel specifications	BACT-PSD	2 gr S/100 SCF gas	
Progress Bartow Power Plant		BACT-PSD	2 gr S/100 SCF gas	
FPL West County Energy Center	Low sulfur fuel	BACT-PSD	2 gr S/100 SCF gas	

Table 6: PGU PM Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Low sulfur natural gas	BACT-PSD	PM_{10}: 0.0078 lb/MMBtu $PM_{2.5}$: 0.0020 lb/MMBtu	1-hr average
Other BACT Determinations for PM_{10}				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0050 lb/MMBtu	No duct burner
Lawton Energy Cogen Facility	Good combustion practices	BACT-PSD	0.0067 lb/MMBtu	
Rocky Mountain Energy Center	Natural gas and good combustion practices	BACT-PSD	0.0074 lb/MMBtu	
PSO Southwestern Power Plant	Natural gas and efficient combustion	BACT-PSD	0.0093 lb/MMBtu	
Fairbault Energy Park		BACT-PSD	0.01 lb/MMBtu	Natural gas
Blythe Energy Project II	Low sulfur natural gas	BACT-PSD	0.0103 lb/MMBtu	
Plaquemine Cogeneration Facility	Clean burning fuel	BACT-PSD	0.0116 lb/MMBtu	Hourly maximum
Nacogdoches Power Sterne Generating Facility	Pipeline natural gas	BACT-PSD	0.0415 lb/MMBtu	
INEOS Chocolate Bayou Facility	Proper combustion control and natural gas	BACT-PSD	0.0840 lb/MMBtu	
Kleen Energy Systems, LLC		BACT-PSD	11 lb/hr	No duct burner
Carty Plant	Clean fuel	BACT-PSD	2.5 lb/MMcf	
FPL West County Energy Center		BACT-PSD	2 gr S/100 scf gas	
Langley Gulch Power Plant	Good combustion practices	BACT-PSD		
Other BACT Determinations for $PM_{2.5}$				
King Power Station	Low ash fuel and good combustion practices	BACT-PSD	0.0024 lb/MMBtu	
Ninemile Point Electric Generating Plant	Low ash fuel and good combustion practices	BACT-PSD	0.0037 lb/MMBtu	1-hour average
International Station Power Plant	Good combustion practices	BACT-PSD	0.0066 lb/MMBtu	3-hour average
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0251 lb/MMBtu	1-hour average

Table 7: PGU VOC Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Oxidation Catalyst	BACT-PSD	1 ppm	1-hr average
Other BACT Determinations				
Chouteau Power Plant	Good combustion	LAER	0.3 ppm	3-hr avg
FPL West County Energy Center Unit 3		BACT-PSD	1.2 ppm	
Progress Bartow Power Plant	Good combustion	LAER	1.2 ppm	
Ninemile Point Electric Generating Plant	Good combustion practices	BACT-PSD	1.4 ppm	1-hr avg without duct burner
Fairbault Energy Park		BACT-PSD	1.5 ppm	
FPL West County Energy Center		BACT-PSD	1.5 ppm	
King Power Station	DLN and oxidation catalyst	BACT-PSD	1.8 ppm	3-hr rolling average
Plant McDonough Combined Cycle	Oxidation catalyst	BACT-PSD	1.8 ppm	3-hr avg
Applied Energy LLC	Oxidation Catalyst	BACT-PSD	2 ppm	1-hr avg
Langley Gulch Power Plant	Catalytic Oxidation, DLN and good combustion practices	BACT-PSD	2 ppm	3-hr rolling
Live Oaks Power Plant	Good combustion practices, catalytic oxidation	BACT-PSD	2 ppm	3-hr average
Otay Mesa Energy Center LLC		BACT-PSD	2 ppm	1 hr
Pattillo Branch Power Plant	Oxidation catalyst	Other	2 ppm	3-hr rolling avg
Thomas C. Ferguson Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	2 ppm	3-hr
Madison Bell Energy Center	Good combustion practices	BACT-PSD	2.5 ppm	1-hr rolling avg
Athens Generating Plant	Good combustion control	BACT-PSD	4 ppm	3-hr block avg
Natural Gas-Fired Power Generation Facility	Good combustion practices	BACT-PSD	4 ppm	24-hr rolling avg
Northern States Power Co. DBA Xcel Energy-Riverside Plant	Good combustion practices	BACT-PSD	4.6 ppm	3-hr block
Rocky Mountain Energy Center	Good combustion practices and oxidation catalyst	BACT-PSD	0.0029 lb/MMBtu	
Arsenal Hill Power Plant	Proper operating practices	BACT-PSD	0.0057 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility	Good combustion practices	BACT-PSD	0.0212 lb/MMBtu	
INEOS Chocolate Bayou Facility	Proper combustion control	BACT-PSD	0.0514 lb/MMBtu	
Pearsall Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	0.8864 lb/MMBtu	
Kleen Energy Systems		LAER	10 lb/hr	Without duct burner

Table 8: PGU Sulfuric Acid Mist Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Natural gas	BACT-PSD	3.66 lb/hr 0.006 lb/MMBtu	12-month rolling average
Other BACT Determinations				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0004 lb/MMBtu	
Arsenal Hill Power Plant	Low sulfur fuel	BACT-PSD	0.0009 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility		BACT-PSD	0.0020 lb/MMBtu	
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0103 lb/MMBtu	1-hour average
INEOS Chocolate Bayou Facility	Low sulfur fuel	BACT-PSD	0.0162 lb/MMBtu	

How about expressing GHE limit as lb/MMBtu?

Table 9: PGU NH3 Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Best management practices	T-BACT	5.0 ppm	24-hr avg
Other BACT Determinations				
Kleen Energy Systems, LLC		BACT-PSD	2 ppm	
Cane Island Power Park		BACT-PSD	5 ppm	
FPL West County Energy Center		BACT-PSD	5 ppm	
FPL West County Energy Center Unit 3		BACT-PSD	5 ppm	
Progress Bartow Power Plant			5 ppm	
Thomas C. Ferguson Power Plant	Best management practices	BACT-PSD	7 ppm	
Nacogdoches Power Sterne Generating Facility		BACT-PSD	0.0259 lb/MMBtu	
INEOS Chocolate Bayou Facility		BACT-PSD	0.0708 lb/MMBtu	

Table 10: GHEC BACT Limits for Auxiliary Boiler

Pollutant	Averaging Period	Limit
NO_X @ 15% O_2[b]	1-hour average	9 ppm
CO @ 15% O_2[c]	1-hour average	50 ppm
SO_2	1-hour average	0.0058 lb/MMBtu
	Rolling annual average	0.0029 lb/MMBtu
PM_{10} (total)	1-hour average	0.005 lb/MMBtu
$PM_{2.5}$ (filterable)	1-hour average	0.005 lb/MMBtu
VOC[d]	1-hour average	0.004 lb/MMBtu

Table 11: Auxiliary Boiler RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Emission Unit
American Municipal Power Generating Station	Meigs, OH	10-8-09	150 MMBTU/H
Caithnes Bellport Energy Center	Suffolk, NY	5-10-06	29.4 MMBTU/H
Carty Plant	Portland, OR	12-29-10	91 MMBTU/H
Chouteau Power Plant	Mayes, OK	1-23-09	33.5 MMBTU/H
Concord Steam Corporation	Merrimack, NH	2-27-09	76.7 MMBTU/H
FPL West County Energy Center	Palm Beach, FL	1-10-07	99.8 MMBTU/H
Karn Weadock Generating Complex	Bay, MI	12-29-09	220 MMBTU/H
Lawton Energy Cogen Facility	Comanche, OH	12-12-06	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Ramsey, MN	5-16-06	160 MMBTU/H
Plant McDonough Combined Cycle	Cobb, GA	1-7-08	200 MMBTU/H
Progress Bartow Power Plant	Pinellas, FL	1-26-07	99 MMBTU/H

Table 12: Auxiliary Boiler Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE (NOx)				
Grays Harbor Energy		BACT-PSD	0.0109 lb/MMBtu 9 ppm	
Other BACT Determinations (NOx)				
Caithnes Bellport Energy Center	Low NO_X burners and flue gas recirculation	BACT-PSD	0.011 lb/MMBtu	
Karn Weadock Generating Complex	Low NO_X burners	BACT-PSD	0.018 lb/MMBtu	30-day rolling average
Lawton Energy Cogen Facility	Dry low NO_X burners	BACT-PSD	0.036 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	0.04 lb/MMBtu	
Concord Steam Corporation	Low NO_X burners, flue gas recirculation	LAER	0.049 lb/MMBtu	Average of 3 1-hr test runs
Carty Plant	Low NO_X burners	BACT-PSD	0.049 lb/MMBtu	
Chouteau Power Plant	Low NO_X burners	BACT-PSD	0.07 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.14 lb/MMBtu	
Current BACT Limits for GHE (CO)				
Grays Harbor Energy		BACT-PSD	0.0369 lb/MMBtu 50 ppm	
Other BACT Determinations (CO)				
Karn Weadock Generating Complex	Efficient Combustion		0.035 lb/MMBtu	Test method
Caithnes Bellport Energy Center	Good combustion practices	BACT-PSD	0.036 lb/MMBtu	
Plant McDonough Combined Cycle		BACT-PSD	0.037 lb/MMBtu	3-hr average
FPL West County Energy Center		BACT-PSD	0.08 lb/MMBtu	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practice	BACT-PSD	0.08 lb/MMBtu	3-hr average
Progress Bartow Power Plant		BACT-PSD	0.08 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.084 lb/MMBtu	
Chouteau Power Plant	Good combustion practice		0.1499 lb/MMBtu	
Current BACT Limits for GHE (SO_2)				
Grays Harbor Energy		BACT-PSD	0.0058 lb/MMBtu 0.0029 lb/MMBtu	1-hr average Annual avg
Other BACT Determinations (SO_2)				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0005 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.0006 lb/MMBtu	

Table 12: Auxiliary Boiler Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Chouteau Power Plant	Low sulfur fuel		0.0009 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Current BACT Limits for GHE (PM_{10} and $PM_{2.5}$)				
Grays Harbor Energy		BACT-PSD	0.005 lb/MMBtu	1-hr average
Other BACT Determinations (PM_{10})				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0033 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.0076 lb/MMBtu	
Carty Plant	Low sulfur fuel	BACT-PSD	2.5 lb/MMcf	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Current BACT Limits for GHE (VOCs)				
Grays Harbor Energy		BACT-PSD	0.004 lb/MMBtu	1-hr average
Other BACT Determinations (VOCs)				
Karn Weadock Generating Complex	Good combustion practices	BACT-PSD	0.0013 lb/MMBtu	Test Method
Chouteau Power Plant	Good combustion practices	BACT-PSD	0.0161 lb/MMBtu	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practices	BACT-PSD	0.005 lb/MMBtu	3-hr average
Plant McDonough Combined Cycle		LAER	0.0051 lb/MMBtu	3-hr average
American Municipal Power Generating Station		BACT-PSD	0.0055 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Progress Bartow Power Plant		BACT-PSD	2 gr S / 100 SCF	

Table 13: Emergency Diesel Engine RBLC Search Results Summary

Facility and Emission Unit	Location County, State	Permit Date or Update	Output per Emission Unit
International Station Power Plant	Anchorage, AK	12-20-10	1500 KW-e
Langley Gulch Power Plant – Fire Pump	Payette, ID	6-25-10	235 KW
Langley Gulch Power Plant – Emergency Generator	Payette, ID	6-25-10	750 KW
Chouteau Power Plant – Emergency Generator	Mayes, OK	01-23-09	2200 HP
Chouteau Power Plant – Fire Pump	Mayes, OK	01-23-09	267 HP
Cane Island Power Park – Fire Pump	Osceola, FL	09-08-08	
Cane Island Power Park – Emergency Generator	Osceola, FL	09-08-08	
FPL West County Energy Center Unit 3	Palm Beach, FL	07-30-08	21 MMBtu/Hr
Arsenal Hill Power Plant	Caddo, LA	03-20-08	310 HP
Fairbault Energy Park	Rice, MN	06-05-07	1750 KW
Blythe Energy Project II	Riverside, CA	04-25-07	303 HP
Progress Bartow Energy Plant	Pinellas, FL	01-26-07	
FPL West County Energy Center – Emergency Generators	Palm Beach, FL	01-10-07	4 x 2250 KW
FPL West County Energy Center – Fire pump	Palm Beach, FL	01-10-07	
Karn Weadock Generating Complex	Bay, MI	12-29-09	2000 KW

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project – Emergency Generator	Meet 40 CFR 60 Subpart IIII	BACT-PSD	NO_x: 2.98 g/bhp-hr CO: 2.61 g/bhp-hr PM: 0.15 g/bhp-hr	
Grays Harbor Energy Project – Fire Pump	Meet 40 CFR 60 Subpart IIII	BACT-PSD	NO_x: 3.0 g/bhp-hr PM: 0.15 g/bhp-hr	
Other BACT Determinations (NOx)				
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	2.98 g/bhp-hr	NOx+NMHC
Cane Island Power Park – Fire Pump		BACT-PSD	3 g/bhp-hr	
International Station Power Plant	Turbocharger and Aftercooler	BACT-PSD	4.77 g/bhp-hr	Instantaneous
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	4.77 g/bhp-hr	NOx+NMHC
Chouteau Power Plant – Emergency Generator		BACT-PSD	4.77 g/bhp-hr	
Cane Island Power Park – Emergency Generator		BACT-PSD	4.8 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	5.10 lb/hr	
FPL West County Energy Center Unit 3		BACT-PSD	6.9 g/bhp-hr	
FPL West County Energy Center – Emergency Generator		BACT-PSD	6.9 g/bhp-hr	
Progress Bartow Energy Plant		BACT-PSD	7.8 g/bhp-hr	
FPL West County Energy Center – Fire pump		BACT-PSD	7.8 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	10.9 g/bhp-hr	3-hr average
Blythe Energy Project II		BACT-PSD	11.23 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuels, limiting operating hours and maintenance	BACT-PSD	14.06 g/bhp-hr	Max
Other BACT Determinations (CO)				
Blythe Energy Project II		BACT-PSD	1.05 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	2.49 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	2.6 g/bhp-hr	
Cane Island Power Park – Fire Pump		BACT-PSD	2.6 g/bhp-hr	
Cane Island Power Park – Emergency Generator		BACT-PSD	2.6 g/bhp-hr	
FPL West County Energy Center – Fire pump		BACT-PSD	2.6 g/bhp-hr	

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Progress Bartow Energy Plant		BACT-PSD	2.6 g/bhp-hr	
Karn Weadock Generating Complex	Low sulfur fuel	BACT-PSD	2.61 g/bhp-hr	
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	2.61g/bhp-hr	
Chouteau Power Plant – Emergency Generator		BACT-PSD	2.61 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuels, limiting operating hours and maintenance	BACT-PSD	3.03 g/bhp-hr	
FPL West County Energy Center Unit 3		BACT-PSD	8 g/bhp-hr	
FPL West County Energy Center – Emergency Generator		BACT-PSD	8.5 g/bhp-hr	
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD		
Other BACT Determinations (PM)				
Karn Weadock Generating Complex	Low sulfur fuel	BACT-PSD	0.066 g/bhp-hr	
Chouteau Power Plant – Emergency Generator		BACT-PSD	0.15 g/bhp-hr	
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	0.15 g/bhp-hr	
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	0.15 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	0.318 g/bhp-hr	3-hr average
FPL West County Energy Center Unit 3 – Emergency Generator		BACT-PSD	0.4 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	0.41 g/bhp-hr	
Other BACT Determinations (SO_2)				
Fairbault Energy Park		BACT-PSD	0.181 g/bhp-hr	3-hr average
Chouteau Power Plant – Emergency Generator	Low sulfur diesel	BACT-PSD	0.184 g/bhp-hr	
Chouteau Power Plant – Fire Pump	Low sulfur diesel	BACT-PSD	0.187 g/bhp-hr	
Arsenal Hill Power Plant	Ultra low sulfur diesel	BACT-PSD	0.94 g/bhp-hr	Max
Cane Island Power Park – Fire Pump		BACT-PSD		
Cane Island Power Park – Emergency Generator		BACT-PSD	0.0015 % S	By weight
FPL West County Energy Center Unit 3	Ultra low sulfur diesel	BACT-PSD	0.0015 % S	
FPL West County Energy Center		BACT-PSD	0.0015 % S	

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Other BACT Determinations (VOC)				
Fairbault Energy Park		BACT-PSD	0.318 g/bhp-hr	3-hr average
Chouteau Power Plant – Emergency Generator	Good combustion practices	BACT-PSD	0.32 g/bhp-hr	
Chouteau Power Plant – Fire Pump	Good combustion practices	BACT-PSD	1.121 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuel	BACT-PSD	1.127 g/bhp-hr	Max
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	2.98 g/bhp-hr	NOx + NMHC
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	4.77 g/bhp-hr	NOx + NMHC

Table 15: Cooling Tower RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Langley Gulch Power Plant	Payette, ID	06-25-10	63200 gal/min
Chouteau Power Plant	Mayes, OK	01-23-09	9 cells
Plaquemine Cogeneration Facility	Iberville, LA	07-23-08	
FPL West County Energy Center	Palm Beach, FL	01-10-07	306000 gal/min
Arsenal Hill Power Plant	Caddo, LA	03-20-08	140000 gal/min
Cane Island Power Park	Osceola, FL	09-08-08	
FPL West County Energy Unit 3	Palm Beach, FL	07-30-08	
Crystal River Power Plant	Citrus, FL	10-12-07	342306 gal/min
Wolf Hollow Power Plant No. 2	Hood, TX	03-03-10	

Table 16: Cooling Tower Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE (PM)				
Grays Harbor Energy Project	Drift Eliminators	BACT-PSD	0.0005% drift	24-hr average
Other BACT Determinations (PM)				
Chouteau Power Plant	Drift Eliminators	BACT-PSD	3.6 lb/hr	24-hr average
Plaquemine Cogeneration Facility	Good operating practices	BACT-PSD	1.4 lb/hr	Hourly max
Arsenal Hill Power Plant	Use of mist eliminators	BACT-PSD	1.4 lb/hr	Max
FPL West County Energy Unit 3		BACT-PSD	0.0005 % Drift	
Crystal River Power Plant		BACT-PSD	0.0005 % Drift	
Wolf Hollow Power Plant No. 2	Drift eliminators	BACT-PSD	0.0005 % Drift	

Combined-Cycle Combustion Turbine Project

Greenhouse Gas Best Available Control Technology Analysis

Grays Harbor Energy Center,
Units 3 and 4
Satsop, Washington

Prepared for:
Grays Harbor Energy, LLC and Grays Harbor Energy II, LLC
Satsop, Washington

Prepared by:
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Date:
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Project Number:
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1 Introduction

Grays Harbor Energy, LLC and Grays Harbor Energy II, LCC (collectively GHE) propose to construct and operate two combustion turbine generators (Units 3 and 4), and one steam turbine generator in a combined cycle at the existing Grays Harbor Energy Center (GHEC) electrical power generating facility. The combustion turbines would both be either GE 7FA.03 or GE 7FA.04 units. The existing natural gas pipeline system will provide fuel to the new units, which would increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MWe.

On May 13, 2010, the U.S. Environmental Protection Agency (EPA) issued the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing greenhouse gas (GHG) emissions from stationary sources, by "tailoring" the major source applicability thresholds under the Prevention of Significant Deterioration (PSD) and Title V air operating permit programs and providing a phased implementation for GHG permitting requirements. The Tailoring Rule defines GHGs as an aggregate of: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Under the second phase of the Tailoring Rule, which began on July 1, 2011, if an existing facility with the potential to emit GHGs of 100,000 tpy CO_{2e} or more proposes a project that will result in a GHG emissions increase of 75,000 tpy CO_{2e} or more, then the project is subject to PSD review for GHGs, even if it will not significantly increase emissions of any other PSD pollutant.

Because the PSD permit was signed on December 21, 2011, before the Tailoring Rule went into effect, the project was not subject to PSD review for GHGs. It is not clear that a request to extend a permit issued prior to the effective date of the Tailoring Rule is subject to the requirements of the Tailoring Rule as a result of a permit extension request that occurs after the Tailoring Rule has gone into effect. Rather than dispute the point, GHE has conservatively assumed that the project is now subject to the requirements of the Tailoring Rule.

The existing facility is a major source of GHGs (i.e., a potential to emit greater than 100,000 tpy CO_2e), and the modification is expected to emit GHGs at a rate greater than 75,000 tpy CO_2e, thus, the Units 3 and 4 Expansion Project is subject to PSD review for GHGs. Because there are no ambient standards or increments for GHGs, the only PSD requirement that applies to GHGs is that Best Available Control Technology (BACT) must be employed to reduce GHG emissions from the proposed project.

1.1 Project Information

The proposed addition to the existing electric power generating facility would be comprised of the following major pieces of equipment:

- Two Power Generation Units (PGUs), each consisting of a Combustion Turbine Generator (CTG) and an associated Heat Recovery Steam Generator (HRSG) with Duct Burning Capability,
- One Steam Turbine Generator (STG),
- One Ten-Cell Cooling Tower,
- One Auxiliary Boiler,

- One Diesel-Powered Back-Up Generator
- One Diesel-Powered Emergency Fire Pump, and
- Five High-Voltage Circuit Breakers.

The PGU, Auxiliary Boiler, Diesel-Powered Back-Up Generator, Diesel-Powered Emergency Fire Pump, and High-Voltage Circuit Breakers are expected to emit GHGs.

1.2 BACT Analysis Process

BACT is defined at 40 CFR 52.21(b)(12) as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The process for conducting BACT analyses for criteria pollutants is relatively well established because it has been implemented for decades. In contrast, BACT analyses and BACT determinations for GHGs are relatively new and few in number. This, combined with the lack of cost-effectiveness criteria for GHGs and far less available guidance, results in a much more limited "body of precedent" upon which to base GHG BACT analyses at this time. In preparing this BACT analysis, ENVIRON reviewed available information in the EPA's RACT/BACT/LAER Clearinghouse, GHG BACT analyses and permits that include GHG limits, EPA comments on GHG BACT determinations and permit limits, guidance documents posted on EPA's GHG permitting webpage, and other available information.

In November 2010, EPA issued guidance for conducting BACT analyses for GHGs which was updated in March 2011 (hereafter referred to as "the March 2011 Guidance"). EPA recommended (but does not require) that permitting agencies apply to GHGs the same "top down" process applied to determine criteria pollutant BACT. The top-down analysis process is comprised of the following steps:

- Step 1 – Identify Available Control Technologies. Identify all available control techniques that could potentially be applied to control emissions of the regulated pollutants from the emission units.

- Step 2 – Eliminate Technically Infeasible Alternatives. If any of the control techniques cannot be successfully used on the emission units due to technical difficulties, document this finding. Such control techniques would not be considered further in the BACT analysis.

- Step 3 – Rank Technically Feasible Alternatives. Assess the performance of each control technique and rank them beginning with the most effective control technique.

- Step 4 – Evaluate Economic, Energy, and Environmental Impacts. Estimate emission reductions, annual costs, cost effectiveness, energy impacts, and other environmental impacts of the controls techniques. Detailed cost effectiveness information is presented for the most effective control and for other control techniques that are in the least cost envelope.

- Step 5 – Select BACT. Identify the most effective option not rejected based on energy, environmental, and economic impacts.

BACT is applied on a case-by-case basis, and selection of BACT frequently requires discretion and judgment to balance competing interests. While EPA established and recommends usage of the five-step, top-down process to determine BACT, it is not a binding requirement . In this case, however, the BACT analysis presented here follows the EPA-recommended five-step, top-down process, which is applied to each individual emission unit.

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2 Project Greenhouse Gas Emissions

The project has the potential to emit four of the six gases that fall within the Tailoring Rule definition of GHGs: CO_2, CH_4, N_2O, and SF_6. The Tailoring Rule further defines CO_2e as the sum of the mass emissions of the constituent GHG, each multiplied by the appropriate global warming potential (GWP) factor provided in Table A-1 of the Federal Mandatory GHG Reporting Rule (MRR, codified in 40 CFR Part 98). Table 2-1 summarizes the calculations and shows that the project has the potential to generate a maximum of approximately 2,515,769 tons of CO_2e per year.

Table 2-1: Proposed Facility GHG Emissions

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[2]	
					(lb/hr)	(tpy)
PGU (2 Units)	4,901 MMBtu/hr	8,760	CO_2	117 lb/MMBtu	572,812	2,508,917
			CH_4	0.00220 lb/MMBtu	10.8	47.3
			N_2O	0.000220 lb/MMBtu	1.08	4.73
			CO_2e	--	573,374	2,511,377
Auxiliary Boiler	29.3 MMBtu/hr	2,500	CO_2	117 lb/MMBtu	3,425	4,281
			CH_4	0.00220 lb/MMBtu	0.0646	0.0807
			N_2O	0.000220 lb/MMBtu	0.00646	0.00807
			CO_2e	--	3,428	4,285
Back-up Generator Diesel Engine	31.9 gal/hr	100	CO_2	22.5 lb/gal	718	35.9
			CH_4	0.000913 lb/gal	0.0291	0.00146
			N_2O	0.000183 lb/gal	0.00582	0.000291
			CO_2e	--	720	36.0
Emergency Fire Pump Diesel Engine	16.5 gal/hr	100	CO_2	22.5 lb/gal	371	18.6
			CH_4	0.000913 lb/gal	0.0151	0.000753
			N_2O	0.000183 lb/gal	0.00301	0.000151
			CO_2e	--	373	18.6
Switchyard Circuit Breakers	133 lb SF_6/unit[4]	3 units	SF_6	1% leakage/year/unit[6]	0.000455	0.00200
			CO_2e		10.9	47.7
Generator Circuit Breakers	15.8 lb SF_6/unit[5]	2 units	SF_6	1% leakage/year/unit[6]	0.000036	0.00016
			CO_2e		0.9	3.8
Total	--		CO_2	--	577,326	2,513,252
			CH_4		10.9	47.4
			N_2O		1.10	4.74
			SF_6		0.000492	0.002153
			CO_2e		577,906	2,515,769

1 The emission factors for combustion of natural gas (for the PGUs and Auxiliary Boiler) and distillate fuel oil No. 2 (for the diesel engines) were obtained from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu and lb/gallon emission factors were calculated using the 2.2046 lb/kg conversion factor.

2 100-year time horizon global warming potential (GWP – from 40 CFR Part 98, Table A-1.

3 Emission rates for the individual GHGs were calculated by multiplying the emission factor by the maximum annual heat input or fuel use. CO_2e was calculated for each emission unit by multiplying the individual GHG emission rate by the appropriate 100-year time horizon global warming potential (GWP) factor from 40 CFR Part 98, Table A-1 (GWP factors used were: CO_2 – 1, CH_4 – 21, N_2O – 310, SF_6 – 23,900), and summing. For example, the CO_2e emission rate was calculated for the PGUs as follows:
(572,812 lb CO_2/hr * 1 lb CO_2e/lb CO_2) + (10.8 lb CH_4/hr * 21 lb CO_2e/lb CH_4) + (1.08 lb N_2O/hr * 310 lb CO_2e/lb N_2O) = 572,812 lb CO_2e/hr + 227 lb CO_2e/hr + 335 lb CO_2e/hr = 573,374 lb CO_2e/hr

4 Quantity of SF_6 in an ABB 242PMR switchyard circuit breaker.

5 Quantity of SF_6 in an ABB HGC3 generator circuit breaker.

6 Worst-case expected leakage rate, based on current industry standard.

3 Power Generation Unit

The combustion turbines and the duct burners associated with HRSGs that comprise the PGUs would combust pipeline natural gas exclusively. As indicated in the previous section, the PGUs would emit the three GHGs associated with combustion: CO_2, CH_4, and N_2O.

3.1 Step 1 – Identify Available Control Alternatives

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for the emissions unit and pollutant undergoing the BACT analysis. Available control technologies are those with a practical potential for application to the particular pollutant and emissions unit under review, which have been demonstrated in practice on full scale operations and are commercially available. Pollutant emission reduction options can be grouped into two categories:

- Inherently lower-emitting processes, practices or designs; and,
- Add-on control technologies.

Emission reduction options can sometimes be used in combination.

In the March 2011 Guidance document, EPA acknowledges that, although "clean fuels" are to be considered in step 1 of the BACT analysis, the initial list of control options does not need to include "clean fuel" options that that would fundamentally redefine the source. In this case, use of pipeline natural gas is part of the original design of the project, and is one of the, if not the, lowest-carbon fuel available. Clearly, substitution of any other fuel would drastically alter the proposed project. As a result, no electrical generation technology other than a natural gas-fired combined-cycle combustion turbine system is considered in this analysis.

3.1.1 Inherently Lower-Emitting Processes, Practices or Design

An inherently lower-emitting process is one that maximizes product yield and thermal efficiency while minimizing pollutant emissions. For electrical generation, this is typically achieved by utilizing state-of-the-art equipment design that converts as much fuel as possible to electricity, minimizes energy use, or uses clean fuels. For GHGs, clean fuels are "low-carbon" fuels or those that combust most efficiently, thereby emitting fewer GHGs per unit of heat input.

The following inherently lower-emitting processes, practices and design options are included as "available" control options for the consideration of BACT in this analysis, and all can be considered in combination. All of these control options are also considered technically feasible for the project.

- Use of lower-emitting and lower-carbon fuel; and
- Energy efficient equipment.

3.1.2 Add-On Control Technologies

In Step 1 of a top-down BACT analysis, the permit applicant and the permitting authority should consider control technologies that have a practical potential to reduce GHG emissions from the emission unit in question. EPA guidance provides that, in Step 1, permit applicants need only include control

technologies that have been demonstrated in practice on full scale operations and that are commercially available at the time the permit application is prepared.[1]

3.1.2.1 Carbon Capture and Sequestration (CCS)

The only potential add-on control technology for removing CO_2 (which constitutes greater than 99% of the GHG emissions attributable to the project) from a gas stream is typically referred to as "carbon capture and sequestration" (CCS), which consists of three stages: (1) removing or otherwise segregating CO_2 from the gas stream, (2) compressing and transporting the CO_2 to a storage facility, and (3) storing the CO_2 on a permanent or long-term basis (e.g., until a practical and economic use is identified).

Post-combustion CO_2 reduction is typically referred to as "carbon capture and sequestration or storage" (CCS), which consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2. Technology exists for all three components of CCS, but they have not yet been deployed at a scale necessary to achieve GHG reduction targets. While components of CCS have been used commercially to produce CO_2 from coal-fired power plants, applications have been limited to capturing relatively small fractions of the CO_2 present in the exhaust to produce food and chemical grade CO_2. Scaling up of current CCS technology to capture the majority of the CO_2 produced by a power plant poses significant engineering challenges, and is not expected to become a commercial reality for over a decade.[2] Nevertheless, per the March 2011 Guidance, CCS technology is considered an available add-on control technology for reducing CO_2 emissions from fossil fuel-fired power plants.

3.1.2.2 Add-On Control Options for Non-CO_2 GHGs

Add-on technologies to remove CH_4 and N_2O exist (e.g., thermal and catalytic oxidation, non-selective catalytic reduction), but none have been employed to remove these GHG compounds from combined-cycle combustion turbines, or from combustion sources in general. Furthermore, CH_4 and N_2O emissions comprise only approximately 0.1% of the total projected GHG emissions increase; thus, application of add-on technology to reduce these pollutants would not have a practical effect on the overall GHG emission rate, even if such control were found to be technically feasible. Therefore, no add-on technologies for removal of CH_4 or N_2O will be considered in this BACT analysis.

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[1] For example, the 1990 Draft NSR Manual, states that control options should be considered "to the extent that the technologies have been successfully demonstrated in practice on full scale operations. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." The Manual further states, "Although not required in step 1, the applicant may also evaluate and propose innovative technologies as BACT. In essence, if a developing technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates, in that an innovative technology is still under development, and has not been demonstrated in a commercial application on identical or similar emission units."

[2] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

3.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

In Step 1, energy efficiency, use of lower-emitting fuel, and CCS were identified as potential control technologies.

3.2.1 Energy Efficiency

Maximizing the quantity of steam and electricity generated per unit of fuel combusted is the goal of most power plant designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

3.2.2 Use of Lower-Emitting Fuel

As discussed in Step 1, natural gas is considered to be the fossil fuel that produces the least quantity of GHGs per unit of heat input. While the combustion turbines are capable of burning other fuels, natural gas is the only fuel proposed for use in the combustion turbine and duct burners.

3.2.3 Carbon Capture and Sequestration

As stated previously, CCS consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2.

There are three approaches to CO_2 capture that are generally applicable to power generation:

- Pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas,
- Post-combustion systems designed to separate CO_2 from flue gas, and
- Oxy-combustion that uses high-purity oxygen (O_2) instead of air, which produces flue gas composed largely of CO_2.

The first approach is really applicable to pipeline natural gas, which has had most of the CO_2 removed from the raw gas prior to being placed the pipeline for consumption. The third option, while technically feasible, is still in the development phase, and, therefore, not available commercially. Only post-combustion systems will be considered for application to the proposed PGU.

Compression and transport of CO_2 is a mature technology, and is therefore considered technically feasible.

There are four endpoints for captured CO_2: (1) geologic sequestration, (2) ocean sequestration, (3) mineral carbonation, and (4) industrial use. Some forms of geologic sequestration, such as injection into depleted oil and gas reservoirs, use in enhanced oil and gas recovery, and injection into underground saline formations are technically feasible. Others, like enhanced coal bed methane recovery, are still being developed and demonstrated. Ocean sequestration, either by injecting and dissolving CO_2 into the water column, or depositing it on the ocean floor where CO_2 is denser than water, is still in the research phase, and therefore not technically feasible. Similarly, mineral carbonation, where CO_2 is reacted with

metal oxides to form stable carbonates is in the demonstration phase, and is therefore not technically feasible. There are many mature industrial uses for CO_2, but the demand is limited, and most uses do not permanently store the CO_2, emitting it later in a product lifecycle.

In summary, there are technically feasible approaches to each of the three phases required for a CCS system; therefore, CCS is considered technically feasible for reducing CO_2 emissions from the proposed PGUs.

3.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective. Before ranking all feasible control alternatives from the previous section, the effectiveness of each is discussed.

3.3.1 Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures. The manufacturer indicates that the proposed PGUs will be capable of achieving a net efficiency of between 46 and 51 percent, and a net heat rate of between 6,665 and 7,503 British thermal units per kilowatt-hour (Btu/kWh), depending upon which generation combustion turbine is installed, the operational mode, and the ambient conditions. Operating at maximum load with duct firing, under design conditions, the net efficiency of the model 7FA.03 combustion turbine is expected to be 47 percent, and the net heat rate is expected to be 7,260 Btu/kWh. The model 7FA.04 is expected to have a 48 percent net efficiency, and an expected net heat rate of 7,115 Btu/kWh.

Maximum energy efficiency is the goal of every power generation facility, but some designs are able to achieve more efficient operation than others. Table 3-1 presents the thermal efficiencies of several recently-permitted power plants which featured natural gas-fired combined-cycle combustion turbines.

Table 3-1: Comparison of Thermal Efficiency of Recent Combined-Cycle Power Plants

Facility	Date Permit Issued (Issuing Agency)	Facility Size (MW)	Thermal Efficiency (LHV)
Grays Harbor Energy Center Units 3 & 4	12/21/2010 (EFSEC)	650	51% 7,503 Btu/kWh
Kalama Energy Center	Pending (WA Ecology)	346	57.5%
CPV Vaca Station Power Plant	Pending (Y-SAQMD)	660	55%
Palmdale Hybrid Power Project	10/18/2011 (EPA Region 9)	530/598/560	56.5%/57.3%/57.3% 7,319 Btu/kWh
Thomas C. Ferguson Power Plant	9/1/2011 (TCEQ)	590	7,730 Btu/kWh
Entergy Ninemile Point Electric Generating Plant	8/16/2011 (LDEQ)	600	7,630 Btu/kWh (HHV)
Avenal Energy Power Plant	5/27/2011 (EPA Region 9)	600	50.5%

Victorville 2 Hybrid Power Project	3/11/2010 (EPA Region 9)	563	52.7% (w/ duct burner) 59.0% (thermal solar)
Russell Energy Center	2/3/2010 (BAAQMD)	600	56.4% 7,730 Btu/kWh
Lodi Energy Center	1/22/2010 (SJVAPCD)	294	55.6%
Colusa Generation Station	10/14/2008 (EPA Region 9)	660	56%
Blythe Energy Project Phase II	4/25/2007 (EPA Region 9)	520	55 – 58%
SMUD Consumnes Phase I	9/9/2003 (CEC)	500	55.1%
Palomar Energy Project	8/8/2003 (CEC)	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)

As shown in Table 3-1, the maximum efficiency of the proposed project is comparable to other recently permitted projects. Of the projects listed, only Russell Energy Center (voluntarily) and those receiving permits after January 2, 2011 (except Avenal Energy, which was grandfathered by EPA) underwent GHG BACT analyses. It should be noted that the maximum heat rate of the proposed PGUs is less than the Washington GHG Emission Performance standard (RCW 80.80), which requires that baseload electric generation facilities not emit regulated GHGs at a rate greater than 1,100 lb CO_2e/MWh (net).

3.3.2 Use of Lower-Emitting Fuel

Natural gas is the only fuel proposed for use in the combustion turbine and duct burners, and is, therefore, considered part of the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to this measure.

3.3.3 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction, but because the quantities of those GHGs is so small, the degradation is slight. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

3.3.4 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis
- Energy Efficiency – Baseline

3.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because energy efficiency and use of natural gas are considered baseline GHG control alternatives, only CCS was evaluated for economic, energy, and environmental impacts.

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the PGU flue gas, as well as to compress it for transport and storage. In the case of a combined-cycle combustion turbine, the concentration of CO_2 in the exhaust gas is dilute (i.e., between 4 and 6 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

In November 2010, the U.S. Department of Energy (DOE) National Energy Technology Laboratory published a document establishing performance and cost estimates for fossil energy plants with and without CCS systems installed. For a net 555 MWe natural gas-fired combined cycle power plant, the cost of CO_2 avoided using CCS was $95 per ton.[3] This is considerably higher than the 2013 auction reserve price set by California's GHG cap and trade rules ($10 per metric ton, or approximately $11 per short ton). It should be noted that adding the CCS system reduced the net plant efficiency by 7.4 percent, reduced the net power output by 81.5 MWe, and increased the normalized water withdrawal by 95 percent. In reality, rather than operating with a reduced net power output, the maximum design heat input would be increased to achieve a net power output equivalent to an equivalent facility without CCS, which would increase emissions of other GHGs (i.e., CH_4 and N_2O), as well as criteria and toxic air pollutants.

The considerable monetary and energy requirements of a CCS system suggest unacceptable collateral economic, energy, and environmental impacts. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed PGU.

3.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the proposed PGUs is an energy-efficient system design. GHE proposes a 12-month rolling total GHG emissions limit of 2,470,034 tons of CO_2e per year (tons CO_2e/yr) for two model 7FA.03 combustion turbines, and 2,511,377 tons CO_2e/yr for two model 7FA.04 combustion turbines. In addition, GHE proposes to maintain the PGUs such that the GHG emission rate per unit of electricity produced would not exceed 878 lb CO_2e/MW on a 12-month rolling average for the model 7FA.03 combustion turbines, and 859 lb CO_2e/MW for the model 7FA.04. The mass emission limit is based on continuous operation of both

[3] National Energy Technology Laboratory. Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity. Revision 2, November 2010. DOE/NETL-2010/1397.

PGUs at 100 percent load with duct firing, and the heat rate limit is based on worst-case operation (low load and high ambient temperature).

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4 Auxiliary Boiler

The auxiliary boiler would combust exclusively natural gas and emit only the three combustion GHG gases (CO_2, CH_4, and N_2O). The auxiliary boiler generates steam to allow the steam turbine associated with the PGU to start more quickly, which allows the facility to be responsive to changing load demands. It will operate no more than 2,500 hours per year.

4.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

4.1.1 Use of Lower-Emitting Fuel

In the case of GHGs, a "clean fuel," or "low-carbon fuel" is one that generates the least amount of CO_2 when combusted. The fuel that produces the least CO_2 while allowing the operational flexibility needed to fulfill the boiler's role at the facility is natural gas. No other alternative fuels will be considered in the BACT analysis.

4.1.2 Inherently Lower-Emitting Processes, Practices or Design

Maximizing the overall efficiency of the boiler minimizes the fuel combusted per unit of steam generated, which minimizes the quantity of CO_2 generated per unit of steam. In addition, proper combustion practices and properly designed equipment can minimize non-CO_2 GHG emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air.

4.1.3 Add-On Control Technologies

As discussed in the PGU BACT analysis section, the only add-on control available to reduce CO_2 is CCS. Add-on technologies to reduce CH_4 and N_2O have not been employed to reduce GHG emissions from combustion sources, and the potential for such technologies to have a meaningful impact on overall GHG emission rates is doubtful. As for the PGUs, no add-on technologies for removal of CH_4 or N_2O will be considered as BACT for the auxiliary boiler.

4.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated. In Step 1, the use of energy efficiency and CCS were identified as potential GHG control technologies.

4.2.1 Energy Efficiency

Maximizing the quantity of steam generated per unit of fuel combusted is the goal of most boiler designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

4.2.2 Use of Lower-Emitting Fuel

As discussed in Step 1, natural gas is considered to be the fossil fuel that produces the least quantity of GHGs per unit of heat input, and is the only fuel proposed for use in the auxiliary boiler.

4.2.3 Carbon Capture and Sequestration (CCS)

As discussed in the PGU BACT analysis, CCS systems that feature post-combustion CO_2 capture schemes are considered technically feasible for reducing CO_2 emitted by combustion units.

4.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility are ranked, starting with the most effective. The March 2011 Guidance says that "to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than the total mass or mass for the individual GHGs. Before ranking all feasible control alternatives from the previous section, the effectiveness of each on a CO_2e basis is discussed.

4.3.1 Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures.

4.3.2 Use of Lower-Emitting Fuel

Natural gas is the only fuel proposed for use in the auxiliary boiler, and is, therefore, considered part of the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to this measure.

4.3.3 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

4.3.4 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline
- Lower-Emitting Fuels – Baseline

4.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because energy efficiency and use of natural gas are considered baseline GHG control alternatives, only CCS was evaluated for economic, energy, and environmental impacts.

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the boiler flue gas, as well as to compress it for transport and storage. In the case of a natural gas-fired boiler, the concentration of CO_2 in the exhaust gas is dilute (i.e., between 4 and 6 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

Most cost information related to CCS technology focuses on fossil fuel (particularly coal) combustion, natural gas processing, and syngas production operations. U.S. Department of Energy analyses indicate that application of post-combustion CCS technology to a new nominal 550 MWe net output power plant would cost approximately $95 per ton of CO_2 avoided.[4] This is considerably higher than the 2013 auction reserve price set by California's GHG cap and trade rules ($10 per metric ton, or approximately $11 per short ton), even without accounting for the economy of scale realized by a 550 MWe unit as compared to that of a 29.3 MMBtu/hr unit (which could potentially generate approximately 3 MWe).

The considerable monetary and energy requirements of a CCS system suggest unacceptable economic, energy, and environmental impacts. The increased energy requirements would result in additional emissions of all pollutants other than CO_2, and, therefore, CCS systems have an unacceptable collateral environmental impact as well. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed auxiliary boiler.

4.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the natural gas-fired auxiliary boiler is energy-efficient system design, and proper combustion practices. GHE proposes a rolling 12-month average GHG emissions limit of 190 pounds of CO_2e per thousand pounds of steam produced (lb/klb steam).

[4] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

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5 Reciprocating Internal Combustion Engines

A diesel-fueled back-up generator will be available to assist with an orderly shutdown of the PGUs in the unusual situation that electrical power is not available from the grid during a shutdown. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection if a fire were to occur when grid power is unavailable. The engines will each operate no more than 100 hours per 12-month rolling period for maintenance and testing.

5.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

The purpose of the two proposed diesel-fueled engines associated with the project is to provide quickly deployable sources of power that rely on an immediately available fuel source for use during emergency situations. The limited operation proposed for the engines under non-emergency conditions is solely intended to maintain the engines in proper working order to enable them to fulfill their emergency role should that become necessary.

Diesel engines are a well-developed technology with a long-standing reputation for reliability, and diesel fuel is a stable, easily stored source of energy. These qualities make a diesel engine the ideal candidate to supply the critical power needs of a facility when grid power is unavailable. While lower emitting processes and cleaner (i.e., lower carbon-containing) fuels undoubtedly exist, none offer the unique qualities that a diesel engine can provide for emergency power services. For this reason, no alternative processes or fuels are considered for this analysis. However, within the category of reliable diesel engines that provide sufficient power for the assigned task, use of the most efficient available model will result in the least GHG emissions.

GHG-reducing add-on technologies exist, and have been discussed at length in this document for application to a natural gas-fired combustion turbine and a natural gas-fired boiler. Because the engines must be available quickly and reliably, add-on controls that complicate operation and potentially reduce engine readiness compromise the emergency role of the engines, and are therefore unacceptable for consideration as GHG-reducing technologies for emergency diesel engines.

5.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

Use of the most efficient diesel engine that is capable of reliably providing sufficient power in timely manner is a technically feasible means of limiting GHG emissions from the emergency diesel engines.

5.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective.

The only alternative considered is the use of the most efficient diesel engines that do not compromise the availability and rapid deployment of the engines for emergency duty.

5.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because only one alternative is considered, there is no opportunity to compare and contrast the collateral impacts of competing technologies.

5.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the diesel-fueled emergency engines is the use of the most efficient engines capable of providing reliable and timely operation to fulfill the assigned emergency roles. At this evolutionary stage of the project, specific units have not yet been identified, but they will be similar in size and design to the following:

- Emergency Back-Up Generator – approximately 400 kWe, powered by an approximately 600 hp diesel-fired engine
- Emergency Firewater Pump Engine – powered by an approximately 275 hp diesel-fired engine

6 High-Voltage Circuit Breakers

The switchyard that will be installed to interconnect the PGU to the electrical transmission system (the "grid") will include high-voltage circuit breakers that will provide a means to isolate portions of the switchyard for service and to protect circuits from damage due to overload or short circuit conditions. In addition, there will be generator circuit breakers that make it possible to separate the combustion turbine generators from the main transmission system. GHE proposes to install 3 (three) 242 kV-class switchyard circuit breakers (maximum rated voltage 245 kV), and 2 (two) 7.7 kA-class generator circuit breakers (maximum rated short-circuit breaking current 63 kA) that use sulfur hexafluoride (SF_6) as a dielectric medium to insulate and quench arcing when the current is interrupted. The circuit breakers would not emit SF_6 directly, but an EPA report indicates that even closed-pressure circuit breaker designs have some leakage associated with them.[5]

6.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies. Because circuit breakers do not combust fuel of any kind, clean fuel options do not apply.

Since their introduction in the 1950s, SF_6 circuit breakers have come to dominate the market for high-voltage switchgear because they provide maximum reliability and safety while reducing the physical space and maintenance requirements of the equipment. Current state-of-the-art SF_6 circuit breakers are designed to minimize fugitive emissions to be a close to zero as possible. Industry guidelines and standards limit SF_6 leakage to 0.5 percent per year (National Electrical Manufacturers Association), or 0.1 percent per year (International Electro-technical Commission), and leakage rates for new systems are typically below 0.2 percent per year. A leak-detection program to promptly identify and eliminate fugitive emissions would further reduce the potential for SF_6 emissions.

Older, less reliable technologies with much greater space and materials requirements that utilize oil or air as the insulating and quenching media are still used at existing operations, but new breakers that use these designs are not available with the specifications required by KEC. Circuit breakers that use a vacuum as an arc-quenching media are popular for medium-voltage applications; research and development of high-voltage applications is currently underway, but high-voltage vacuum circuit breakers that do not rely on any SF_6 are not yet commercially available. Development of a replacement for SF_6 is ongoing, but none has yet been identified that can match the safety, reliability, and materials reduction capabilities provided by SF_6.

6.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

[5] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), SF6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006, available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

Use of state-of-the-art SF_6 circuit breakers, with or without a leak detection and repair program, is a technically feasible approach for reducing SF_6 emissions from high-voltage circuit breakers.

Use of circuit breakers with air-, oil-, or vacuum-based designs is not technically feasible because designs of these types are not commercially available with the capacity required by the proposed project. Representatives of the three leading high-voltage circuit breaker manufacturers (ABB, Mitsubishi, and Siemens) were contacted, and each confirmed that there are no alternatives to SF_6 in the 242 kV-class of high-voltage circuit breakers, nor for the 7.7 kA-class of generator circuit breakers.

6.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective.

- State-of-the-art SF_6 circuit breakers with a leak detection and repair program
- State-of-the-art SF_6 circuit breakers

6.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because the most effective alternative is proposed as BACT, an impacts analysis is not necessary. Nevertheless, while SF_6 is considered the most potent GHG, the reduction in net GHG emissions that modern circuit breaker designs are able to realize as a result of the minimization of materials and pressurization requirements afforded by the properties inherent to SF_6, more than compensates for the high GWP value.

6.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the high-voltage circuit breakers is the use of current state-of-the-art closed pressure SF_6 circuit breakers, operated in conjunction with a leak detection and repair program. At this evolutionary stage of the project, specific makes and models have not yet been identified, but they will be in the 242 kV class (245 kV maximum rating).

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
VALLEY REGIONAL OFFICE
4411 Early Road, P.O. Box 3000, Harrisonburg, Virginia 22801
(540) 574-7800 Fax (540) 574-7878
www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

Amy Thatcher Owens
Regional Director

December 21, 2010

Mr. Robert B. McKinley
Vice President, Generation Construction
Dominion Resources Service Inc.
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility: Warren County Power Station
Location: Warren County
Registration No.: 81391
Plant ID No.: 51-187-0041

Dear Mr. McKinley:

This letter is in regard to the permit to construct and operate an electric generating facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution, which was hand delivered to Virginia Electric and Power Company on December 17, 2010. This permit supersedes your permit dated July 30, 2004, as amended March 29, 2006, June 5, 2007, January 14, 2008, and September 15, 2009.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on September 3, 2010, and solicited written public comments by placing a newspaper advertisement in the Northern Virginia Daily newspaper on October 9, 2010. A public hearing was held on November 9, 2010. The required comment period, provided by 9 VAC 5-80-1870, expired on November 24, 2010. The State Air Pollution Control Board gave direct consideration to the proposed permit at its December 17, 2010 meeting and instructed DEQ to issue the permit on its behalf.

This permit approval to construct and operate shall not relieve Virginia Electric and Power Company of the responsibility to comply with all other local, state, and federal permit regulations.

The proposed emergency generator (EG-1) and emergency fire water pump (FWP-1) appear to be affected facilities under the NSPS *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* (located at 40 CFR 60, Subpart IIII) and the Maximum Achievable Control Technology (MACT) *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* (located at 40 CFR 63, Subpart ZZZZ). DEQ advises you to review the NSPS and MACT regulations to ensure compliance with the applicable emission and operational limitations. As the owner/operator, you are responsible for the monitoring, notification, recordkeeping, and reporting requirements of these NSPS and MACT regulations. Notifications should be sent to the U.S. Environmental Protection Agency, Region III.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

A copy of the results of performance tests required by 40 CFR 60, Subparts Dc, IIII, and KKKK shall be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

If you have any questions concerning this permit, please call Anita Riggleman of the Valley Regional Office at (540) 574-7852.

Sincerely,

Amy T. Owens
Regional Director

Attachments: Permit
40 CFR Part 60, Subparts Dc, IIII, and KKKK (via electronic mail)
40 CFR Part 63, Subpart ZZZZ (via electronic mail)

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Air Enforcement Branch (3AP20), U.S. EPA, Region III
Inspector, Air Compliance
Gerallyn Duke, U.S. EPA, Region III (electronic file submission)

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

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David K. Paylor
Director

Amy Thatcher Owens
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

This permit supersedes your permit dated July 30, 2004, as amended March 29, 2006, June 5, 2007, January 14, 2008, and September 15, 2009.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 81391
Plant ID No.: 51-187-0041

is authorized to construct and operate

an electric power generation facility

located at

Lots 3, 5, 6, 7, 8, 9, and 10, Warren Industrial Park
Warren County

in accordance with the Conditions of this permit.

Approved: Amy R Owens

Regional Director

17 December 2010

Signature Date

Permit consists of 35 pages.
Permit Conditions 1 to 75.
Source Testing Report Format
Attachments A and B

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition. All parts per million (ppm) are parts per million by volume on a dry gas basis (ppmvd), corrected to 15 percent oxygen, unless otherwise stated. All heat inputs in British thermal units (Btu) are based on higher heating values.

INTRODUCTION

This permit approval is based on the permit applications dated January 7, 2010, January 18, 2010, February 12, 2010, March 16, 2010, April 14, 2010, April 23, 2010, June 24, 2010, July 2, 2010, July 27, 2010, August 6, 2010, August 24, 2010, August 27, 2010, September 1, 2010 (2 items), September 2, 2010, and September 24, 2010 and supplemental information dated April 27, 2010 and May 20, 2010. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. Equipment List

Equipment to be constructed at this facility consists of:

- three combined-cycle power generating units (T-1, T-2, & T-3) where each unit includes the following emission units:

- one Mitsubishi natural gas-fired combustion turbine (CT) generator, Model M501 GAC, rated at 299,600 kW and 2,996 million Btu per hour heat input (CT-1, CT-2, & CT-3) (NSPS Subpart KKKK); and
- one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1, DB2, & DB3) (NSPS Subpart KKKK);

– one natural gas-fired auxiliary boiler, rated at 88.1 million Btu per hour heat input (B-1) (NSPS Subpart Dc);

– one natural gas-fired fuel gas heater, rated at 52.0 million Btu per hour heat input (GH-1) (NSPS Subpart Dc);

– one diesel-fired emergency generator, rated at 2,193 HP (EG-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (FWP-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– three turbine inlet chillers (600,000 gal/hr each) (IC-1, IC-2, & IC-3); and

– one 6,000 gallon distillate oil storage tank (ST-1).

(9 VAC 5-80-1100 and 9 VAC 5-80-1605 A)

PROCESS REQUIREMENTS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

2. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by use of a two-stage, lean pre-mix dry low-NO_x combustor, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practices. The SCR system shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

3. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

4. **Emission Controls: Volatile Organic Compounds** – Volatile Organic Compound (VOC) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

5. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

6. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

7. **Monitoring Device Observation: SCR** – The devices used to continuously measure ammonia feed rate, gas stream flow rate, and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

8. **Monitoring Device Observation: Oxidation Catalyst** - The devices used to continuously measure catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

PROCESS REQUIREMENTS - EMERGENCY UNITS (EG-1 & FWP-1)

9. **Monitoring Devices –** The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the

startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-80-1180 D and 40 CFR 60.4209)

10. **Maintenance and Operation** – The permittee must maintain and operate the emergency generator (EG-1) and the emergency fire water pump (FWP-1) according to the manufacturer's written instructions, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.4206 and 40 CFR 60.4211)

PROCESS REQUIREMENTS - AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)

11. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by ultra low-NO_x burners.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

12. **Emission Controls: Carbon Monoxide and Volatile Organic Compounds** - CO and VOC emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by good combustion practices, operator training and proper emissions unit design, construction and maintenance. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations, at minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

OPERATING/EMISSION LIMITATIONS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

13. **Fuel** - The approved fuel for each CT (CT-1, CT-2, & CT-3) and each HRSG duct burner (DB1, DB2, & DB3) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, and 40 CFR 60.4330(a)(2))

14. **Fuel Throughput** – The combustion turbines (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) combined shall consume no more than 90,073 x 10^6 scf of natural

gas per year. Throughput shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

15. **Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas being fired at the electric power generation facility is 0.0003 percent by weight or less (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet), to demonstrate that potential sulfur dioxide emissions shall not exceed the limits specified in Condition 16.

If the permittee elects not to demonstrate the sulfur content using the above option, the permittee may:

a. determine and record the total sulfur content of the natural gas once per unit operating day or

b. develop custom schedules for determination of the total sulfur content of the natural gas, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

(9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.4365(a), 40 CFR 60.4370(b) and 40 CFR 60.4370(c))

16. **Short-Term Emission Limits** - Emissions from the operation of each combined-cycle power generating unit (T-1, T-2, & T-3) shall not exceed the limits specified below:

	Short term emission limits
PM-10 (includes condensable PM)	▪ 8.0 lb/hr without duct burner firing ▪ 14.0 lb/hr with duct burner firing ▪ 0.0027 lb/MMBtu without duct burner firing ▪ 0.0040 lb/MMBtu with duct burner firing
PM-2.5*	▪ 8.0 lb/hr without duct burner firing* ▪ 14.0 lb/hr with duct burner firing* ▪ 0.0027 lb/MMBtu without duct burner firing* ▪ 0.0040 lb/MMBtu with duct burner firing*
Sulfur dioxide	▪ 0.98 lb/hr ▪ 0.00028 lb/MMBtu
Oxides of nitrogen (as NO_2)	▪ 25.3 lb/hr ▪ 2.0 ppmvd
Carbon monoxide	▪ 9.9 lb/hr and 1.5 ppmvd without duct burner firing ▪ 17.4 lb/hr and 2.4 ppmvd with duct burner firing

Volatile organic compounds	▪ 2.6 lb/hr and 0.7 ppmvd without duct burner firing ▪ 6.1 lb/hr and 1.6 ppmvd with duct burner firing
Sulfuric acid mist (H_2SO_4)	▪ 0.00013 lb/MMBtu without duct burner firing ▪ 0.00025 lb/MMBtu with duct burner firing

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides and carbon monoxide, which shall be calculated as a one-hour average.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 18 of this permit.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, and 43.

* This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4320, and 40 CFR 60.4330)

17. **Annual Emission Limits –** Total emissions from the operation of all three combined-cycle power generating units (T-1, T-2, & T-3) including duct burners shall not exceed the limits specified below:

Pollutant	Annual Emissions (tons)
PM-10 (includes condensable PM)	159.1
PM-2.5	159.1*
Sulfur Dioxide	12.3
Oxides of Nitrogen (as NO_2)	317.7
Carbon Monoxide	348.6
Volatile Organic Compounds	181.0
Sulfuric Acid Mist (H_2SO_4)	9.5

* This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, 14, and 43.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

18. **Startup/Shutdown** – The short-term emission limits contained in Condition 16 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed 4.2 hours per occurrence.

ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed 2.1 hours per occurrence.

iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 1.5 hours per occurrence.

iv. Shutdown – refers to the period between the time the turbine load drops below 60 percent operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 0.5 hours per occurrence.

b. The permittee shall operate the Continuous Emission Monitoring Systems (CEMS) during periods of startup and shutdown.

c. The permittee shall record the time, date and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180, and 9 VAC 5-80-1705)

19. **Emission Limits: Duct Burners** – Emissions from the operation of each duct burner (DB1, DB2, & DB3) operating independently of each combined-cycle system (T-1, T-2, & T-3) shall not exceed 54 ppm of oxides of nitrogen (expressed as NO_2) at 15 percent O_2.
(9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4320)

20. **Duct Burner Operational Restriction** – The duct burners (DB1, DB2, & DB3) shall not operate between the hours of 10 p.m. and 5 a.m. Eastern Standard Time (EST) during the period between September 1st and April 30th, except that the duct burners may be operated during a Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) Independent System Operator's (ISO) declared emergency. This duct burner operational restriction is included to demonstrate that the project will not cause or contribute to an exceedance of the applicable PM-2.5 PSD Class I increment as of the trigger date, October 20, 2011.
(9 VAC 5-80-1180, Virginia Code 10.1 1307.02., and Virginia Code 10.1-1307.3 A.5.)

21. **Pollution Prevention: Ammonia** – Emissions of ammonia resulting from unreacted ammonia emitted from the SCR (ammonia slip) shall not exceed 2 ppmvd during steady-state conditions and 5 ppmvd during non-steady-state operations. Compliance with the ammonia slip limit shall be determined based on a one-hour block average. Steady-state operation is based on a steady load for the duration of the CEMs hour and is defined as less than a 5% rate of load change within the hour. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia slip and demonstrating compliance with the ammonia slip limit from each SCR system to the DEQ. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia slip limit at least 95% of the time the SCR is operating. Compliance with the 95% time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior 30 days, compliance with the 95 percent limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 5-170-160, and Virginia Pollution Prevention Act, § 10.1-1425.11)

22. **Visible Emission Limit** - Visible emissions from each combined-cycle (T-1, T-2, & T-3) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 18), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260, and 9 VAC 5-80-1705)

23. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the CTs (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

AIR QUALITY RELATED VALUES

24. **Source Reductions and Emission Offsets –** The permittee shall implement the following actions to secure a total of emission offsets equal to the Total Annual NO_x Limit, (i.e. the sum of NO_x limits for the combustion turbines, duct burners and emergency engines in Conditions 17, 30, 31, 39, and 40) ("TANL") at the Facility. The National Park Service has determined that for the Warren County Power Station these actions provide full mitigation or acceptable net environmental benefits for all potential or actual adverse impacts to Air Quality Related Values, including visibility and aquatic resources, at Shenandoah National Park (SNP).

a. Definitions – Solely for the purposes of this permit Condition 24, the following definitions shall apply:

i. "Emissions Offsets" means Emission Reduction Credits, Allowances under the Acid Rain Program or other emissions reductions that are obtained to mitigate potential impacts of the permitted facility on the air quality and related values in SNP.

ii. "Eligible SO_2 Allowances" mean those Allowances (as defined in the Clean Air Act, section 402(3)) that originate from Dominion owned facilities in the region shown on Attachment A ("Originating Account").

iii. "Eligible NO_x Allowances" mean any NO_x Allowances as that term is defined in a federally-approved NO_x emissions trading program.

iv. "Facility NO_x Emission Ton" means each ton of NO_x emissions from the permitted facility.

v. "Allowable Annual NO_x Emissions" means 330.7 tons NO_x per year, which represents the maximum Facility NO_x Emission Tons authorized under the permit.

vi. "Emissions Reduction Credits" means the number of tons per year of creditable emissions reductions.

vii. "Offset Ratio" means the ratios shown on the map at Attachment A.

b. Emission Offsets from specific facilities – The permittee shall secure a reduction in emissions from a source or sources in the manner prescribed as follows:

i. The permittee shall permanently cease all permitted SO_2 and NO_x emissions at North Branch Power Station in Grant County, West Virginia. Based on the actual emissions in 2007-2008 and the distance and direction of North Branch Power Station from the Park these reductions shall result in an Emission Offset of 243 TPY toward the TANL offset requirement. Neither the permitted nor actual SO_2

and NO_x emission reductions from the North Branch Power Station may be used as Emissions Offsets for any other purpose.

ii. The permittee shall retire permanently the 175 TPY of NO_x offsets procured from World Kitchen in Martinsburg, West Virginia approved by the DEQ by letter of 11/17/07. Based on the distance and direction of World Kitchen from the Park, this retirement of emission reduction credits shall result in 17.5 TPY emission offsets toward the TANL requirement.

c. Allowances or Emission Reduction Credits retirements

The permittee shall secure and retire Eligible SO_2 Allowances, Eligible NO_x Allowances, or Emission Reduction Credits in the amount equivalent to 70.2 TPY of Emission Offsets toward the TANL requirement by a combination of the following.

i. Retire Eligible SO_2 Allowances or Eligible NO_x Allowances by transferring them from the Originating Account each year (by making the appropriate designation(s) in the Allowance Tracking System transfer form) into an account administered by the U.S. EPA for the Acid Rain Program to be identified by the DEQ.

(a) To ensure that Eligible SO_2 Allowance or Eligible NO_x Allowance retirements benefit air quality and related values in SNP, any such Allowance that originates from facilities located in an area with an Offset Ratio (from the Attachment A map) higher than 10:1 shall require retirement of an additional ten percent of Eligible SO_2 Allowances or Eligible NO_x Allowances in order to offset one Facility NO_x Emission Ton. For example, Eligible SO_2 Allowances that originate from the 20:1 Offset Ratio area shall be retired at the rate of 22:1; Eligible SO_2 Allowances that originate from the 30:1 Offset Ratio area shall be retired at the rate of 33:1; and Eligible SO_2 Allowances that originate from the 40:1 Offset Ratio area shall be retired at the rate of 44:1 until all of the Allowable Annual NO_x Emissions are offset.

(b) The permittee is prohibited from replenishing or causing to be replenished those retired allowances in the Originating Account of the specific Dominion unit that the allowances originated from, by securing, purchasing or otherwise acquiring allowances from any other accounts and transferring them into that Originating Account. After the date of initial operation, the only allowances that can be placed in that account are those allocated by EPA to that account of a vintage year of and after startup of the equipment listed in Condition 1.

ii. Secure and retire Emission Reduction Credits multiplied by the Offset Ratio of the plant location shown on Attachment A.

iii. The requirements of c.i. and ii. in equation form are:

(Eligible SO_2 or NO_x $Allowance_{Plant\ in\ area\ of\ 10:1\ Offset\ Ratio\ or\ less}$ /Offset Ratio) +

(Eligible SO_2 or NO_x $Allowance_{Plant\ in\ area\ greater\ than\ 10:1\ Offset\ Ratio}$ /(1.1x Offset Ratio))

$\geq 70.2 - \sum (ERC_{Plant}/\text{Offset Ratio})$

d. Procedure and timing.

i. The actions in items Condition 24 b. and c. shall be completed and in effect prior to startup of the equipment listed in Condition 1.

ii. Prior to startup of the equipment listed in Condition 1, the permittee shall provide to the DEQ written documentation from the air pollution control agency that regulates each of the sources identified in 24 b. and c.ii. that the requirements of Condition 24 b. and c.ii. (if that option is selected) have been met and that the emission reductions are recognized by the agency as creditable, permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the DEQ has approved in writing the documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 24 b. and c.ii. (if that option is selected).

iii. The permittee shall submit a report to the DEQ prior to the commencement of operation of the permitted facility that demonstrates that the Allowances have been retired in accordance with Condition 24.c.i. Annual reports demonstrating compliance with the retirement obligations and prohibition on replenishment in Condition 24 c. i. must be submitted to the DEQ within 90 days of the end of each calendar year (i.e. 30 days after the compliance deadline under the Acid Rain Program). These reports shall continue to be required for the life of the facility or until all obligations under this permit condition are satisfied with permanent emission reductions. To the extent the permittee accepts federally enforceable limitations on the Total Annual NO_x Emissions in the future, the permittee will only be required to retire Eligible SO_2 Allowances or ERCs such that the sum of the retired allowances at a plant multiplied by that plant's Offset Ratio is equal to the new Total Annual NO_x Emissions minus 260.5. All reports shall be sent to the DEQ, and

Superintendent
Shenandoah National Park
3655 U.S. Highway 211 East
Luray, VA 22835

At any time, but after at least 30 days notice to the public and the Federal Land Manager, the DEQ, in consultation with the Federal Land Manager, may approve an alternative

mitigation plan proposed by the permittee in lieu of this condition. At a minimum, such a plan shall result in actual sulfur dioxide or nitrogen oxides reductions from an existing stationary source(s) within one of the areas identified in Attachments A and B of at least the Allowable Annual NO_x Emissions multiplied by the corresponding Offset Ratio. Such reductions must be practically enforceable, permanent, and quantifiable, and must be created after January 19, 2010. The reductions must result in the same or greater reduction in impacts to aquatic resources and visibility to the SNP as the retirements of allowances outlined in paragraphs a through c of this condition.
(9 VAC 5-170-160, 9 VAC 5-80-1180, and 9 VAC 5-80-1985 E)

OPERATING/EMISSION LIMITATIONS – EMERGENCY UNITS (EG-1 & FWP-1)

25. **Fuel** – The approved fuel for the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is distillate fuel oil with a maximum sulfur content per shipment of 0.0015 percent by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4207(b), and 40 CFR 80.510(b))

26. **Operating Hours: Emergency Fire Water Pump** - The emergency fire water pump (FWP-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency fire water pump (FWP-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency fire water pump shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

27. **Operating Hours: Emergency Generator** - The emergency generator (EG-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency generator (EG-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency generator shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

28. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

a. The name of the fuel supplier;

b. The date on which the distillate oil was received;

c. The volume of distillate oil delivered in the shipment; and

d. The sulfur content of the distillate oil.

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 25, as applicable. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits. (9 VAC 5-80-1180)

29. **Emergency Generator and Emergency Fire Water Pump Operation** - The operation of the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is limited to emergency situations. Emergency situations include emergency generator use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted and emergency engine use to pump water in the case of fire or flood, etc. The emergency generator (EG-1) and the emergency fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 52 hours per year for each unit.
(9 VAC 5-80-1180 and 40 CFR 60.4211(e) and 40 CFR 60.4219)

30. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	2.0 lbs/hr	0.5 tons/yr
Carbon Monoxide	1.7 lbs/hr	0.4 tons/yr
Volatile Organic Compounds	2.0 lbs/hr	0.5 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 26.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

31. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	23.1 lbs/hr	5.8 tons/yr
Carbon Monoxide	12.6 lbs/hr	3.2 tons/yr
Volatile Organic Compounds	23.1 lbs/hr	5.8 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 27.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

32. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	4.0 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (c), and 40 CFR 60.4211(c))

33. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	6.4 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (b), and 40 CFR 60.4211(c))

34. **Visible Emission Limit** - Visible emissions from the emergency generator (EG-1) and the emergency fire water pump (FWP-1) shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-80-1180)

35. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the emergency generator (EG-1) and the emergency fire water pump (FWP-1) as described in Condition 1 shall be operated in compliance with the requirements outlined in 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-60-90, 9 VAC 5-60-100, 40 CFR 60 Subpart IIII, and 40 CFR 63 Subpart ZZZZ)

OPERATING/EMISSION LIMITATIONS – AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)

36. **Fuel** – The approved fuel for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

37. **Fuel Throughput** – The auxiliary boiler (B-1) shall consume no more than 756.9 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

38. **Fuel Throughput** – The fuel gas heater (GH-1) shall consume no more than 446.8 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

39. **Emission Limits** - Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	4.24 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	14.27 tons/yr
PM-10/PM-2.5	0.44 lbs/hr	1.93 tons/yr
Volatile Organic Compounds	0.47 lbs/hr	2.08 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 37.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

40. **Emission Limits** - Emissions from the operation of the fuel gas heater (GH-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	2.51 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	8.43 tons/yr
PM-10/PM-2.5	0.39 lbs/hr	1.70 tons/yr
Volatile Organic Compounds	0.28 lbs/hr	1.23 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 38.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

41. **Visible Emission Limit** - Visible emissions from both the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

42. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, and 40 CFR 60 Subpart Dc)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

43. **CEMS** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO, in ppmvd corrected to 15 percent O_2, from each combined-cycle unit (T-1, T-2, & T-3). CEMS for NO_x shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the "Monitoring Requirements" in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 16, NO_x data and CO data shall each be reduced to 1-hour block averages. The relative accuracy test audit (RATA) of the NO_x CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-420, 40 CFR 75, 40 CFR 60.13, and 40 CFR 60.4340(b))

44. **CEMS Performance Evaluations** - Performance evaluations of the NO_x and, if applicable, sulfur dioxide continuous monitoring systems shall be conducted in accordance with 40 CFR 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 75, and 40 CFR 60.4345(a))

45. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4345(e), and 40 CFR 60)

46. **Excess Emissions and Monitor Downtime for NO_x - Continuous Monitoring Systems** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 48 are defined as follows:

a. An excess emission is any unit operating period in which the one-hour average NO_x emission rate exceeds the applicable emission limit in Condition 16; and

b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee uses this information for compliance purposes.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

47. **Excess Emissions and Monitor Downtime for SO_2 - Continuous Monitoring Systems** Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

a. An excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

48. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a continuous emission monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of calendar quarter. These reports shall include, but are not limited to, the following information:

a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, or malfunctions of the process, the nature and cause of the

malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report; and

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a), and 40 CFR 60.4395)

49. **Excess Emissions for Continuous Monitoring Systems –** For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations;

c. Correction of measured NO_x concentrations to 15 percent O_2 is not allowed; and

d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

RECORDS

50. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. The records shall include, but are not limited to:

a. Annual throughput of natural gas to each CT (CT-1, CT-2, & CT-3), calculated monthly as the sum of each consecutive 12-month period.

b. Annual throughput of natural gas to each duct burner (DB1, DB2, & DB3) calculated monthly as the sum of each consecutive 12-month period.

c. Time, date and duration of each startup, shutdown, and malfunction period for each combined-cycle power generating unit (T-1, T-2, & T-3).

d. Annual number of startup and shutdown occurrences for each combined-cycle power generating unit (T-1, T-2, & T-3), calculated monthly as the sum of each consecutive 12-month period.

e. Records to verify sulfur content of pipeline natural gas as required in Condition 15.

f. Continuous records of heat input for each combined-cycle power generating unit (T-1, T-2, & T-3).

g. Continuous records of power output from combined-cycle power generating units (T-1, T-2, & T-3) and the steam turbine generator(s).

h. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 17, 30 and 31, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

i. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

j. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period.

k. Records of time, date, and duration of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing and the operational status of each combined-cycle unit (T-1, T-2, and T-3) during those maintenance checks and readiness testing.

l. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period.

m. All fuel supplier certifications for the emergency units (FWP-1 & EG-1).

n. Records of engine manufacturer data as required by Conditions 32 and 33.

o. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

p. Records for each combined-cycle unit (T-1, T-2, and T-3) showing steady-state vs. non-steady-state operation during a given hour, the ammonia slip monitoring plan, and the ammonia slip monitoring results as required by Condition 21.

q. Scheduled and unscheduled maintenance and operator training.

r. Results of all stack tests, visible emission evaluations, visible emission inspection results, and performance evaluations.

s. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heater (GH-1) calculated monthly as the sum of each consecutive 12-month period.

t. Records of good combustion practices for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as required by Condition 12.

u. Records to verify sulfur content of pipeline natural gas as required in Condition 36.

v. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 39 and 40, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

w. Records related to NO_x offsets as required by Condition 24 d.

x. Records related to the CEMS quality control program as required by Condition 45.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

TESTING

51. **Testing/Monitoring Ports** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendix B).
(9 VAC 5-50-30 F)

52. **Initial Performance Test – Combustion Turbines** - Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for the following pollutants using the specified methods:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile organic compounds (VOC)	40 CFR 60, Appendix A, Method 25A
PM-10 (All particulate matter shall be considered PM-10 and shall include condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19, and 40 CFR 51, Appendix M, Method 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 16. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. CO, VOC and PM-10 emissions shall be determined at each of the operating conditions indicated for each pollutant contained in Condition 16. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.

The permittee shall perform an initial stack test for PM-2.5 in the time frames as required for testing the other pollutants in this condition if a test method for PM-2.5 has received final approval by the USEPA or DEQ at that time. If a test method for PM-2.5 has not received final approval by the USEPA or DEQ at the time initial testing as required in this condition is to be conducted, the permittee shall perform initial stack testing for PM-2.5 within 60 days of final approval of a test method by USEPA or DEQ, or as required by the DEQ. This permit limits for PM-2.5 may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in this condition.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

53. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for oxides of nitrogen (as NO_2) to determine compliance with the limits contained in Condition 16 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_x concentration (in ppm). Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 53.a. above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for NO_x and diluent pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

i. If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent O_2 from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 16 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in Condition 16.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

ii. Compliance with the applicable emission limit in Condition 16 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405, and 40 CFR 60.4400)

54. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in ppm). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, and 40 CFR 60.4415)

55. **Initial Performance Test – Auxiliary Boiler and Fuel Gas Heater** – Initial performance tests shall be conducted on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) for NO_x and CO to determine compliance with the emission limits contained in Conditions 39 and 40. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no

later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

56. **Compliance Demonstration – Duct Burners** – The permittee shall determine compliance with the NO_x emission limits in Condition 19 by complying with the NO_x emission limits contained in Condition 16.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 40 CFR 60.4400 (b)(2))

57. **Visible Emissions Evaluation – Combustion Turbines** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined-cycle generating unit stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions for which emissions tests are required for the stack tests contained in Condition 52. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

Should conditions prevent concurrent opacity observations, the DEQ shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

58. **Visible Emissions Evaluation - Auxiliary Boiler and Fuel Gas Heater** - Concurrently with the initial performance tests in Condition 55, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and fuel gas heater (GH-1). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. Each evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler or fuel gas heater, as applicable, will be operated but in no event later than 180 days after start-up of the unit.

Should conditions prevent concurrent opacity observations, the DEQ, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ,

within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit. (9 VAC 5-50-30 and 9 VAC 5-80-1180)

CONTINUING COMPLIANCE DETERMINATION

59. **Annual Performance Test – Combustion Turbines** – Annual performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4415(a))

60. **Stack Tests** - Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-50-30 G)

61. **Visible Emissions Evaluation – Combustion Turbines** – The permittee shall conduct visible emission inspections on each combined-cycle generating unit (T-1, T-2, & T-3) stack in accordance with the following procedures and frequencies:

a. At a minimum of once per week, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be conducted for a total of 60 minutes.

b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per week for that stack.

c. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

62. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** – The permittee shall conduct visible emission inspections on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks in accordance with the following procedures and frequencies:

a. At a minimum of once per month, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10 percent opacity, the VEE shall be conducted for a total of 60 minutes.

b. All visible emissions inspections shall be performed when the boiler or fuel gas heater (as applicable) is operating.

c. If visible emissions inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per month.

d. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

NOTIFICATIONS

63. **Initial Notifications** - The permittee shall furnish written notification of the following to the DEQ:

a. The actual date on which construction of the electric power generation facility commenced, within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility, within 15 days after such date.

d. The actual date on which construction of the auxiliary boiler commenced, within 30 days after such date.

e. The actual start-up date of the auxiliary boiler, within 15 days after such date.

f. The actual date on which construction of the fuel gas heater commenced, within 30 days after such date.

g. The actual start-up date of the fuel gas heater, within 15 days after such date.

h. The anticipated date of continuous monitoring system performance evaluations, postmarked not less than 30 days prior to such date.

i. The anticipated date of performance tests of the electric power generation facility, postmarked at least 30 days prior to such date.

j. The actual dates on which construction of the emergency generator and emergency fire water pump commenced, within 30 days after such dates.

k. The actual start-up dates of the emergency generator and emergency fire water pump, within 15 days after such dates.

Copies of the written notifications referenced in items a through i above are to be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

64. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

a. A program of continuous construction is not commenced within 18 months from the date of this permit.

b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time. This provision does not apply to the period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date

DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.
(9 VAC 5-80-1210 and 9 VAC 5-80-1985)

65. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

b. Fails to comply with the conditions of this permit;

c. Fails to comply with any emission standards applicable to a permitted emissions unit;

d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1210 F and 9 VAC 5-80-1985)

66. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

67. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

68. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J)

69. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the DEQ, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the DEQ, in writing.
(9 VAC 5-20-180 C)

70. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

71. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the DEQ, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240 and 9 VAC 5-80-1975)

72. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-170-160)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-60-300, *et. seq.* Neither their inclusion in this Prevention of Significant Deterioration Permit nor any resulting public comment period make these terms federally enforceable.

73. **Emission Limits** - Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS #	Hourly Limit	Annual Limit
Acrolein	107-02-8	0.0406 lbs/hr	0.176 tons/yr
Formaldehyde	50-00-0	1.48 lbs/hr	6.34 tons/yr
Cadmium	7440-43-9	0.0115 lbs/hr	0.00551 tons/yr
Chromium	7440-47-3	0.0146 lbs/hr	0.00702 tons/yr
Nickel	7440-02-0	0.0219 lbs/hr	0.0105 tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320, 9 VAC 5-80-1180, and 9 VAC 5-80-1625 G)

74. **Emission Limits** – The permittee shall determine compliance with the toxic pollutants emission limits in Condition 73 as follows:

a. To calculate hourly toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i\right)\left(\frac{100 - CE}{100}\right)$$

..... Equation 1

Where:

E_t = Emission rate of toxic compound (t) (lbs/hr)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

b. To calculate annual toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i T_i\right)\left(\frac{100 - CE}{100}\right)\left(\frac{1ton}{2000lb}\right)$$

..... Equation 2

Where:

E_t = Emission rate of toxic compound (t) (tons/year)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

T_i = Hours of operation for each unit (i) utilized during the time period (hours)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1625 G)

75. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to:

a. Total hours that each unit operates on a monthly basis.

b. Average hourly, monthly and annual emissions (in pounds and tons) of each toxic compound listed in Condition 73. Toxic compound emissions shall be calculated as shown in Condition 74. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.

These records shall be available for inspection by the DEQ and shall be current for at least the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-50-50, and 9 VAC 5-80-1625 G)

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

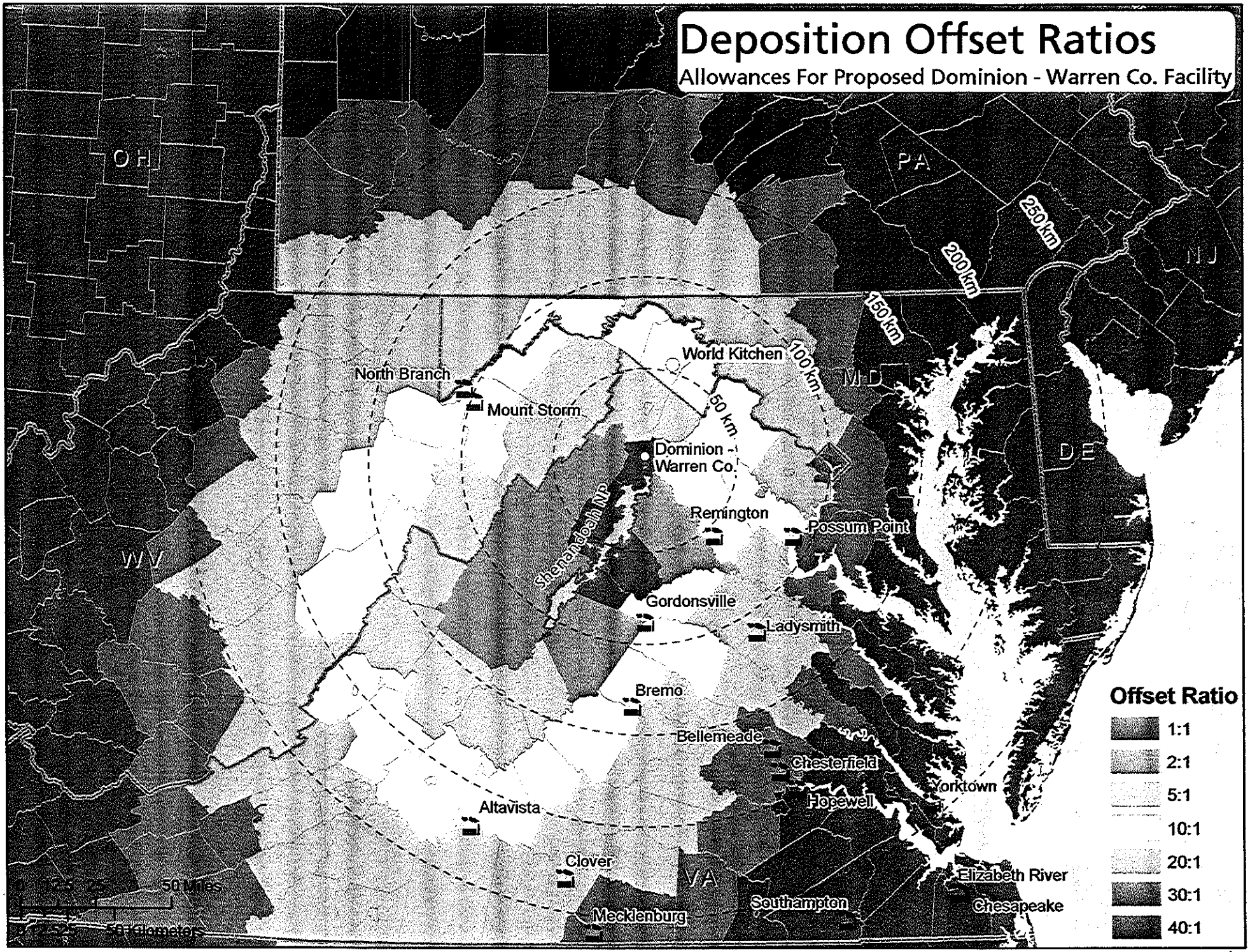
Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

* Not applicable to visible emission evaluations.


Deposition Offset Ratios
Allowances For Proposed Dominion - Warren Co. Facility
OH
PA
NJ
MD
DE
WV
VA
250km
200km
150km
100km
50 km
World Kitchen
North Branch
Mount Storm
Dominion - Warren Co.
Shenandoah NP
Remington
Possum Point
Gordonsville
Ladysmith
Bremo
Bellemeade
Chesterfield
Hopewell
Yorktown
Altavista
Clover
Elizabeth River
Southampton
Chesapeake
Mecklenburg
50 Miles
50 Kilometers
Offset Ratio
1:1
2:1
5:1
10:1
20:1
30:1
40:1

Attachment B: List of Geographic Locations From Which Allowances May Be Obtained

1:1 Locations:

Virginia Counties:	Warren, Page, Madison, and Greene

2:1 Locations:

Virginia Counties:	Shenandoah, Rockingham, Augusta, Albemarle, Culpeper, and Rappahannock
Virginia Cities:	Harrisonburg, Staunton, Waynesboro, and Charlottesville

5:1 Locations:

Virginia Counties:	Frederick, Highland, Bath, Rockbridge, Amherst, and Nelson
Virginia Cities:	Winchester, Lexington, and Buena Vista
West Virginia Counties:	Hampshire, Hardy, and Pendleton

10:1 Locations:

Virginia Counties:	Loudoun, Prince William, Fauquier, Orange, Louisa, Fluvanna, Buckingham, Appomattox, Campbell, Bedford, Botetourt, and Alleghany
Virginia Cities:	Lynchburg, Bedford, and Covington
West Virginia Counties:	Jefferson, Berkeley, Morgan, Mineral, Grant, Tucker, Randolph, and Pocahontas
Maryland Counties:	Allegany

20:1 Locations:

Virginia Counties:	Fairfax, Stafford, Spotsylvania, Caroline, Hanover, Goochland, Powhatan, Amelia, Cumberland, Prince Edward, Nottoway, Lunenburg, Charlotte, Halifax, Pittsylvania, Henry, Patrick, Floyd, Franklin, Montgomery, Roanoke, Craig, and Giles
Virginia Cities:	Fairfax, Manassas Park, Manassas, Fredericksburg, Danville, Martinsville, Roanoke, and Salem
West Virginia Counties:	Monroe, Greenbrier, Nicholas, Webster, Braxton, Lewis, Upshur, Barbour, Harrison, Marion, Taylor, Preston, and Monongalia
Maryland Counties:	Garrett, Washington, Frederick, and Montgomery

Pennsylvania Counties: Greene, Fayette, Somerset, Bedford, Fulton, and Franklin

30:1 Locations:

Virginia Counties: King George, Essex, King William, Henrico, Chesterfield, Dinwiddie, Brunswick, Mecklenburg, Carroll, Grayson, Wythe, Pulaski, and Bland

Virginia Cities: Richmond, Galax, and Radford

West Virginia Counties: Mercer, Summers, Raleigh, Fayette, Clay, Gilmer, and Doddridge

Pennsylvania Counties: Washington, Allegheny, Westmoreland, Armstrong, Indiana, Cambria, Blair, Cumberland, and Adams

Maryland Counties: Carroll, Howard, Prince George's, and Charles

40:1 Locations:

All other jurisdictions within the boundaries of Virginia, North Carolina, Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania, New Jersey, Delaware, and Maryland

Homero Ramirez

From: Trudy Douglass <trudydouglass@att.net>
Sent: Wednesday, April 17, 2013 3:22 PM
To: rworl@energy.ca.gov; PublicAdviser@energy.ca.gov; Leonard Scandura
Subject: PDOC- A threat to the San Joaquin Valley

To:CEC and SJAPCD regarding HECA

From: Trudy Douglass

DOC 08-AFC-8A

April 16, 2013

There is no way that the CEC, SJVAPCD, or HECA can accurately predict pollution emissions because there are no parameters set for the quality of the feedstock or the natural gas to be used. HECA is waiting for the vendors to tell them what the PM10, PM2.5, VOC, and SO2 will be. It seems to me that clearly prescribed limits on levels of mercury, sulfur, lead and other know contaminates would contribute to making HECA a cleaner gasifying factory. Keeping low-grade or adulterated levels of coke, coal and natural gas out of the feedstock will reduce pollution emissions. A system for documenting and testing for compliance should be part of the PDOC and CEC plan.

In analyzing the background ambient air quality of the valley the huge Buttonwillow Safe Harbor dump, I5, and Highway 99 were left out. These sources are not picked up by the Shafter monitor. I believe that I5 and Highway 99 should be included because they are both stationary and a constant source of emissions.

Will sulfur or sulfur dioxide be released at start-up, shut-down or when flaring? A violation of District Rule 4102.

How are the emissions from the three flares burning natural gas 24/7 while on stand be accounted for in your pollution estimates?

Where are the 95,500 gallons per minute of "higher-purity water" for the CCW exchanger in the cooling tower coming from?

How often will the CEMS undergo calibration, audits, and testing? What is the CEMS's margin of error?

How much mercury is expected to be captured? What will be done with it? Will it be put in a toxic waste site or have some practical use?

Are there going to be sound level maximums on the equipment that will load, unload and grind the coal and coke?

What will the noise and lights running 24/7 do to the residents and animals in the area?

What is the projected ambient temperature of the factory site for each of the seasons of the year? What humidity levels can be expected?

What particulate size are the baghouses on all dust suppression systems be expected to retain?

SJVAPCD seems to believe that particulates PM10, PM2.5. and smaller can be released into the air without any consequences to valley residents' health. These particulates will be streaming from almost every ground level

operation in the HECA factory: loading, transporting, unloading, grinding, blending, drying, conveying, and storing. They will come from every material brought in or manufactured: coal, coke, urea, sulfur, ammonium nitrate, waste and products. Even in the gasification process, HECA assumes that the sub-micron range from it's stack will be PM10 but they could as well include PM2.5 particulates. PM10 and PM2.5 will have an emission rate of over 170 tons a year. The district is selling out our valley's air at a bargain price. They are accepting HECA's plan for interpollutant trading of SOx emissions for PM2.5 emissions at a 1:1 ratio. EPA has recommended up to a 40:1 ratio. San Joaquin Valley officials are cheap and easy.

The SJVAPCD has sited several areas for dust and particulate suppression, capture and monitoring, all are to be inspected quarterly. This is not acceptable, it should be done monthly. Also it must be mandatory that any employee, who sees a problem in an area of particulate suppression, report it immediately, have the equipment shut down, and fixed.

The people who live in and work in the area surrounding the HECA factory need protection. $50,000,000 should be set aside to track the air quality related diseases of the Tupman residents and farm personnel in the area. A baseline of all area residents and workers should be taken before construction starts and annual follow-up should be done until the land is fully restored after HECA is closed down. Treatment for identified ailments will be paid for as they manifest, even beyond the original $50,000,000. The people of Tupman are afraid with good reason because this gigantic factory will endanger their futures.

There are many sites in the HECA factory that have monitoring equipment but information on all emissions will not be collected, for example,PM2.5, SO2 and VOC. It seems to me that it would be simpler to combine all the emissions that the factory is generating by placing air quality monitoring equipment on the grounds of Tupman School. Tupman residents can know what they are breathing and be warned in case of "Fugitive Emissions" at the factory.

In looking over the Kern County Planning Department's recommendations, the Kern County Fire Department lists several hazardous and toxic products with flammable characteristics and the potential to produce large quantities of dense, black, toxic smoke. The fire personal will wear the best haz-mat protection there is when responding to a disaster at the HECA factory. But, the people of Tupman, 2 miles distance, and the farmers and workers in fields, even closer, will be in life-threatening danger and have **no** protection. A comprehensive plan to supply equipment, training and an early warning system to notify these residents must be included in the CEC plan. An automatic system that does not rely on HECA to activate it is needed.

Every chemical factory in the last 150 years has become a toxic waste site. Make a land restoration exit plan the cost of HECA doing business Kern County. A $200,000,000 bond or trust to insure that the land will be returned to its currant condition. The last owners of HECA won't be able to declare bankruptcy, abandon the site and walk away.

Leonard Scandura
SJVUAPCD
Via e mail to leonard.scandura@valleyair.org

April 18, 2013

re: Air Districts PDOC for HECA

Here are my comments as an individual and not as a member of any organization.

On Tuesday night, April 02, 2013, we were told that SJVUAPCD's only role with regard to HECA was to determine if HECA conforms to the rules and regulations of the SJVUAPCD. I think it is also the SJVUAPCD's responsibility to help the Valley obtain NAAQS as soon as feasible. Thus, in order for a project to conform to the rules and regulations, it must lead to cleaner air in the next few years. HECA collects coal and/or coke with limestone and collects workers via fossil fuel driven vehicles and also may dispose of coal ash. The SJVUAPCD says it is possible to do this without increasing air pollution because HECA's mitigation fee will reduce air pollution from other sources as much as HECA produces. What justifies SJVUAPCD's perfect confidence in its ability to reduce pollutants by spending mitigation dollars? Is there some way to improve our air by not allowing HECA and spending some money on reducing local production of criteria air pollutants?

How much criteria pollution will HECA have to mitigate, assuming it mitigates all its pollutants? In HECA's early years, is it assumed that HECA will gasify coal from New Mexico that arrives in railroad cars or trucks? What will prevent coal dust from escaping the railroad cars or trucks? Will coal be allowed to litter the ground near the tracks, as it now does along other Kern County tracks? How much pollution would come from the engines of those trains, from operating the facility and from workers and visitors? Will there be any health effects from these emissions?

Does gasifying coal for electricity produce ash and sludge that has significant amounts of arsenic, boron, cadmium, chromium, lead, mercury, and selenium? How much air pollution does it take to remove HECA's coal ash?

Decision makers at the SJVUAPCD may be pressured to determine that HECA conforms to the rules and regulations of the SJVUAPCD because HECA provides jobs. HECA would occupy over 450 acres of prime farmland and use 7500 acre-ft annually of usable agricultural water. The number of agricultural jobs now existing must be subtracted from the number of jobs HECA produces to determine the net increase in jobs to be credited to HECA. HECA will cost federal tax payers $408 million. We should use that money to make more efficient use of

energy. That might save more energy than HECA and burning the oil recovered by HECA, will produce.

How much greenhouse gas will HECA produce? How much greenhouse gas will the oil recovered by injecting HECA's carbon dioxide make when that oil is refined and consumed? How much will HECA have to pay in order to mitigate the greenhouse gas it will produce? Who will mitigate the greenhouse gas the oil recovered by injecting HECA's carbon dioxide makes?

I regret that information did not go out to minority communities in Spanish. Not until March were notices even posted anywhere in Spanish. The minority communities will be most affected in the fields and downwind from the plant. On April 02, 2013, we were told that all future information will be in both English and Spanish.

Thank you for the opportunity to comment,

Arthur Unger
2815 La Cresta Drive
Bakersfield, CA 93305-1719
(661) 323 5569
artunger@att.net preferred

Homero Ramirez

om: Leonard Scandura
Sent: Tuesday, May 14, 2013 12:05 PM
To: Homero Ramirez
Subject: FW: Harold Hanson board member San Joaquin Valley Air Pollution Board

FYI

-----Original Message-----
From: Dave Warner
Sent: Tuesday, May 14, 2013 11:48 AM
To: Leonard Scandura
Subject: FW: Harold Hanson board member San Joaquin Valley Air Pollution Board

Dave Warner
Director of Permit Services
San Joaquin Valley APCD

---Original Message-----
om: Chris Romanini [mailto:roman93311@aol.com]
Sent: Tuesday, May 14, 2013 11:46 AM
To: roman93311@aol.com; city_council@bakersfieldcity.us; hwhanson@cbbank.com
Cc: john.heiser@energy.ca.gov; blake.roberts@energy.ca.gov; Dave Warner; robert.worl@energy.ca.gov
Subject: Re: Harold Hanson board member San Joaquin Valley Air Pollution Board

I just heard back from Mr Hanson. So please, disregard my note from an hour ago, and do not docket. Unfortunately, Mr Hanson is busy with a city council meeting tomorrow during the Air hearing in Buttonwillow and has declined coming. I do hope Hanson has a representative from his council office to attent the hearing so he has a better understanding of what concerns people about HECA. The public puts in efforts to be understood; board members need to put in efforts to hear and represent them.
Chris Romanini

-----Original Message-----
From: Chris Romanini <roman93311@aol.com>
To: city_council <city_council@bakersfieldcity.us>; hwhanson <hwhanson@cbbank.com>
Cc: john.heiser <john.heiser@energy.ca.gov>; blake.roberts <blake.roberts@energy.ca.gov>; dave.warner <dave.warner@valleyair.org>; robert.worl <robert.worl@energy.ca.gov>
Sent: Tue, May 14, 2013 11:00 am
Subject: Harold Hanson board member San Joaquin Valley Air Pollution Board

Mr. Hanson
. m resending my email to you as I have not received a response that you received yesterday's. Since you are a board member of the San Joaquin Air district, please attend the Buttonwillow hearing on HECA so you can understand the public outcry against HECA before you vote,

again. Chris Romanini

docket 08 AFC 8A please post

-----Original Message-----
From: Chris Romanini <roman93311@aol.com>
To: HWHanson <HWHanson@cbBank.com>
Sent: Mon, May 13, 2013 10:10 am
Subject: Harold please attend the Air Hearing in Buttonwillow for HECA

Harold, You have SO much power over our air and health. You need to hear what the public thinks of this HECA project. You were not at the last hearing at the air district, so you did not see the 100 + people who attended and the scores who spoke AGAINST it. To represent us, with all your power, you should have a better understanding of what the people think.

HECA hearing by San Joaquin Valley Air District.....Buttonwillow School, May 15, at 6 pm.

In case you question it,,,,,we do have the WORST air in the nation.
See attached polluted city email.

Chris Romanini

, Bako has earned itself a dubious distinction. The whole central valley of CA, for that matter. Check it out.....
http://homes.yahoo.com/news/america%e2%80%99s-most-polluted-cities--182250757.html

Homero Ramirez

om: Leonard Scandura
Sent: Tuesday, May 14, 2013 7:36 AM
To: Homero Ramirez
Subject: FW: docket HECA 08 AFC 8A

HECA comment

-----Original Message-----
From: Chris Romanini [mailto:roman93311@aol.com]
Sent: Monday, May 13, 2013 7:16 PM
To: robert.worl@energy.ca.gov; Leonard Scandura; Dave Warner
Cc: DTracy10s@aol.com
Subject: docket HECA 08 AFC 8A

Donna Tracy asked me to forward her comments for docketing with the CEC and for comments to the Air District. For some reason they were returned to her.
Please Docket

-----Original Message-----
From: DTracy10S <DTracy10S@aol.com>
To: Roman93311 <Roman93311@aol.com>
Sent: Mon, May 13, 2013 5:42 pm
ıbject: Fwd: docket HECA 08 AFC 8A

Chris,
Here is my letter. I'm not the greatest at expressing myself, but at least it's another no that's being voiced. I rechecked the adresses you sent me.
From: DTracy10S@aol.com
To: Leonard.scandural@valleyair.org, dave.warner@valleyair.org, Robert.wort@energy.ca.gov
Sent: 5/13/2013 4:44:20 P.M. Pacific Daylight Time
Subj: docket HECA 08 AFC 8A

I am opposed to this project. As a Buttonwillow resident I believe it would only add to the pollution in our valley. I find it hard to understand in an area that has some of the worst air in the nation you would want to add to it. The other concern is this area has some of the most productive ag land in the nation and the proponents have not been able to show it would not be harmful. Whatever happened to the idea of placing these types of projects in a low populated, low producing part of our country?
Thank you for your time,
Donna Tracy

Homero Ramirez

From: Hertz Ramirez <hramirez@lcof.net>
Sent: Wednesday, May 15, 2013 8:29 PM
To: Homero Ramirez
Subject: HECA Project

Homero Ramirez,

My name is Hertz Ramirez and I am a resident of Kern County. I have taken a great interest in the HECA project that is to be built near Buttonwillow, CA. After attending the public comment hearing and looking at your presentation, I believe that HECA will comply with the SJVAPCD regulations and meet your standards for Air Quality. That being said, I urge that your decision favor moving forward with the project.

Sent from my iPhone

Homero Ramirez

From:	Mitchell, Julie <julie.mitchell@urs.com>
Sent:	Friday, May 17, 2013 12:35 PM
To:	Leonard Scandura; Homero Ramirez; Leland Villalvazo; Allan Phillips
Cc:	robert.worl@energy.ca.gov; Will Walters (WWalters@aspeneg.com); Marisa Mascaro; michael.carroll@lw.com; Shileikis, Dale; Paul.Detwiler@NETL.DOE.GOV
Subject:	HECA SJVAPCD PDOC Comments
Attachments:	HECA PDOC Comments.pdf

Please find attached a document that contains a table with HECA's comments on the SJVAPCD Preliminary Determination of Compliance and strike-out markup of HECA's requested changes to many of the sections of the PDOC. These include the main PDOC document and Appendices A, C, I and K. This file will also be docketed with the CEC. Please let me know if you have any questions.

Thank you,
Julie Mitchell
Senior Air Quality Scientist
San Diego Air Quality Team Manager
URS Corporation
4225 Executive Square, Suite 1600
La Jolla, CA 92037
858-812-9292 phone
858-812-8273 direct
858-812-9293 fax
Julie.Mitchell@urs.com

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Comments on the Preliminary Determination of Compliance
Hydrogen Energy California (08-AFC-8A)
[May 16, 2013]

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
			General	
1		General comment		Emissions from some sources have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments.
2		General comment		The urea HP and LP absorbers vents were combined into one Urea Absorber vent. The emissions remain the same. The stack parameters change and are presented in the updated air quality emissions and modeling report submitted with these comments.
3		General comment		It has been determined that fluxant will be needed to increase the calcium content of the feedstock to achieve vitreous "glass like" gasification solids. The baghouse associated with the material handling for the fluxant unloading, transfer and storage silo has been added to permit Unit 19.
4		General comment		The methanol storage tank was inadvertently left out of the permit application and will be added to Permit Unit 21.
5		General comment		Fugitive emission calculations were further refined identifying four different streams. Two of these streams will be associated with Permit Unit 21, and two will be associated with Permit Unit 33.
6		General comment		Please change "Coal Dryer" to "Feedstock Dryer" throughout the document.

[1] Printed page number from the PDF of the PDOC.
[2] Text from PDOC that is the subject of the applicant's comment.
[3] Applicant's comment.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
7		General comment		Minor changes to the PDOC have been noted directly in the PDOC in track changes mode.
8		General comment		Minor changes to numbers in the calculations have also been included in track change mode. More significant changes have an explanation in this table. All emissions and changes have been presented in the updated air quality emissions and modeling report submitted with these comments. Emission calculations presented in the PDOC may not exactly match emission calculations presented in the updated air quality emissions and modeling report due to rounding.
9		General comment		$PM_{2.5}$ emissions should be called out consistently for all permit units.
			I Proposal	
10	No comment			
			II Applicable Rules	
11	No comment			
			III Project Location	
12	No comment			
			IV Process Description	
13	All Sections			Minor changes to wording of process descriptions have been made for clarity.
14	Combined Cycle Power Generating System (S-7616-26-0)	4	Combustion Turbine Generator Specification Table	Some proprietary information from this table has been redacted, at the request of MHI.
15	Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)	8	(none)	The fluxant unloading and storage silo will be served by a baghouse to control PM emissions, has been added to this permit unit.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
16	Gasification System (S-7616-21-0)	11	(none)	The methanol storage tank and two additional fugitive streams have been added to this permit unit.
17	Gasification Solids Material Handling System (S-7616-22-0)	12	Example Composition of Gasification Solids	Updated composition has been provided.
18	Sulfur Recovery and Tail Gas Compression System (S-7616-23-0)	13	(None)	Two new maintenance events that will be served by the thermal oxidizer have been added and described – SRU passivation, and presulfiding of the tail gas hydrogenation catalyst.
19	Ammonia Synthesis Unit (S-7616-33-0):	17	However, the plant has also been designed with facilities to load liquid ammonia for sale onto railcars or into trucks for off-site shipment to allow for future operational flexibility.	The sale of ammonia has been removed from the project, thus there will be no offsite transport of ammonia.
20	Ammonia Synthesis Unit (S-7616-33-0):	17	(none)	Two additional fugitive streams have been added to this permit unit.
			V Equipment Listing	
21	Permit Unit S-7616-19-0	22 Permit unit description	FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS	Add fluxant silo and unloading vent baghouse to the unit description Change to "FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE),

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
				TWO ENCLOSED TRANSFER CONVEYORS, FLUXANT SILO AND UNLOADING VENT SERVED BY A DUST COLLECTOR"
22	Permit Unit S-7616-21-0	23 Permit unit description	GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, AND RECTISOL ACID GAS REMOVAL (AGR) UNIT	Add methanol tank to the unit description Change to "GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, RECTISOL ACID GAS REMOVAL (AGR) UNIT, AND METHANOL STORAGE TANK"
23	Permit Unit S-7616-26-0	23 Permit unit description	431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI 501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), AND A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE	Add feedstock dryer to the unit description Change to "431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI M501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), AND A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE AND FEEDSTOCK DRYER (WITH DRYING GAS FROM TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR)"
24	Permit Unit S-7616-31-0	24 Permit unit description	800 MMBTU/HR ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)	Change the rating of the flare to 2,100 MMBTU/HR ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)
25	Permit Unit S-7616-34-0	24 Permit unit description	UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A	Change Permit unit description to "UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS VENTED TO THE UREA ABSORBER VENT; PASTILLATION UNIT WITH A

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
			DUST COLLECTOR	DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR"
			VI Emission Control Technology Evaluation	
26	Power Block CTG/HRSG and Feedstock Dryer Operating Emissions	27	Table 3-3 (Maximum Short-Term Emissions From CTG/HRSG And Coal Dryer Stack During On-Peak Operations), which is located in Appendix F.	Table 3-3 was not included in Appendix F.
27	Power Block CTG/HRSG and Feedstock Dryer Operating Emissions	27-28	Annual emissions	Annual emissions are discussed, but not included in Appendix F. Would recommend adding Table 3-4 to Appendix F.
28	Material Handling Dust Collection:	28		Please add Fluxant unloading and transfer system to description.
29	Tail Gas Thermal Oxidizer	30		Please add description of thermal oxidizer maintenance activities.
30	CO_2 Recovery and Vent System (S-7616-24-0):	31	Table 3-13	Table 3-13 is referenced but not shown. Either label the table of page 31 Table 3-13 or remove the reference to the table number.
31	Ammonia Synthesis Unit with Ammonia Startup Heater (S-7616-33-0):	34	SO_2 emissions are calculated based on 12.65 ppmv total sulfur in pipeline natural gas.	Change to: "SO_2 emissions are calculated based on 1 gr/100 scf total sulfur in pipeline natural gas (per SJVAPCD Policy 1720)."
32	Urea Unit (S-7616-34-0) Urea Absorber	34		Please change description of the Urea Absorber, the HP and LP absorbers vent to a single Urea Absorber stack.
33	Fugitive Emissions:	37	Process Stream Table	Please add the four new fugitive streams, CO_2 product and purification compressors (18a), Urea CO_2 compressor (18b), Lower benzene concentration (22), and Higher benzene concentration (23). Streams 22 and 23 have been added to permit unit S-7616-21. Streams 18a and 18b are included within permit unit S-7616-33.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
34	Fugitive Emissions:	37	The following compounds were included as VOCs (not all compounds are found in the gas in each process stream): methanol, propylene, COS, and H_2S.	Change H_2S to Hydrogen Cyanide. H_2S is not a VOC.
			VII General Calculations	
35		General comment		Tables 3.3 and 3-4 were not included in Appendix F.
36		General comment		$PM_{2.5}$ emissions are not called out consistently for all permit units.
37	Combined Cycle Combustion Turbine Generator (S-7616-26-0):	38	Commissioning emissions will count towards the annual emission limits.	Change to: "Commissioning emissions of NO_X, VOC, SO_X, PM_{10} and $PM_{2.5}$ will count towards the annual emission limits. Commissioning emissions of CO will have a separate limit."
38	Combined Cycle Combustion Turbine Generator (S-7616-26-0):	38	Presented in Table 3-3 (Maximum Short-Term Emissions from CTG/HRSG and Coal Dryer Stack During On-Peak Operations), which is located in Appendix F.	Table 3-3 was not included in Appendix F. Also either label the table of page 40 as Table 3-3 or remove the reference to the table number.
39	Combined Cycle Combustion Turbine Generator (S-7616-26-0):	39	Presented in Table 3-4 (CTG/HRSG and Coal Dryer Maximum Annual Operation Emissions), which is located in Appendix F	Table 3-4 was not included in Appendix F.
40	Footnote of Short-term emission table	40	See Table 3.3 (Maximum Short-Term Emissions from CTG/HRSF and Coal Dryer Stack During On-Peak Operations) in Appendix F.	Table 3.3 was not included in Appendix F.
41	Combined Cycle Combustion Turbine Generator (S-7616-26-0):	41	Feedstock drying Startup Steps	During startup of the CTG/HRSG and feedstock dryer, the steps with feedstock emissions match with steps 2 and 3 in the CTG startup (not steps 1 and 2).
42	Material Handling (all)	49-50, 52, 66	Tables	Updated process weight of material per day and year.
43	Gasification System	51		Added streams #22 and #23 to the description as well as the potential fugitive emissions table. Additionally, the

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	(S-7616-21-0)			methanol tank has been added to this permit unit, and VOC emissions from the tank have been added to the table.
44	Sulfur Recovery and Tail Gas Compression System (S-7616-23-0)	53	Emission Factors for Tail Gas Thermal Oxidizer Tables	Emission factors for the SRU passivation and Presulfiding events have been added in new tables.
45	SRU Fugitive Emissions (S-7616-23-0)	54	Potential Fugitive Emissions for S-7616-23 Table.	Updated emissions reflect design refinements.
46	CO_2 Recovery and Vent System (S-7616-24-0)	54	Vent stream VOC concentration limit.	Short-term VOC emissions are based on 44 ppm (40 ppm methanol, 4 ppm benzene). Long-term emissions are based on 24 ppm (20 ppm methanol, 4 ppm benzene).
47	Cooling Towers (S-7616-27-0, -28-0, and -29-0)	56		It may be beneficial to describe how the $PM_{2.5}$ emissions are calculated here.
48	Cooling Towers	56	Fourth bullet: "Total dissolved solids (TDS) concentration shall not exceed 9,000 ppm for S-7616-21 and -28 (which is proposed by the applicant), which is equivalent to 75.06 lb/1,000 gallon."	Should apply to emission units S-7616-27 and -29 (process cooling tower and power block cooling tower).
49	Cooling Towers	56	Fifth bullet: "TDS concentration shall not exceed 3,000 ppm for S-7616-27…"	• Should apply to unit S-7616-28 (ASU cooling tower). • Should be 2,000 ppm, as shown in their table and what we proposed. • Footnote 11 should also be 2,000 ppm instead of 3,000 ppm. • 2,000 ppm-TDS = (2000/10^6)*(8.34 lb/gal) = 16.68 lb/1000 gal.
50	Gasification Flare (S-7616-30-0)	58	Footnote 15 21,936 MMBtu/hr	Please change the hour to year. Change to: "21,936 MMBtu/yr"
51	Gasification Flare (S-7616-30-0)	59	Table "Emission Factors for Gasification Flare" Footnote 17	SO_X, PM_{10} and VOC emission factors (lb/MMBtu) have been changed from 0.000, to be equal to the syngas emission factor. While these compounds are negligible,

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				they are not zero. Remove footnote 17.
52	SRU Flare (S-7616-31-0):	59	The SRU flare has a maximum flaring capacity of 36 MMBtu/hr with a 0.3 MMBtu/hr natural gas pilot.	Change to "The SRU flare has a maximum design flaring capacity of 2,100 MMBtu/hr, with maximum planned flaring of 36 MMBtu/hr plus a 0.3 MMBtu/hr natural gas pilot."
53	Rectisol Flare (S-7616-32-0):	60	The Rectisol flare is an elevated flare with a maximum rating of 430 MMBtu/hr during planned flaring events, waste gas plus natural gas assist flare, and 0.3 MMBtu/hr natural gas pilot.	Change to "The Rectisol flare is an elevated flare with a maximum design capacity of 5,500 MMBtu/hr, and a maximum rating of 430 MMBtu/hr during planned flaring events, of waste gas plus natural gas assist flare, and 0.3 MMBtu/hr natural gas pilot."
54	Ammonia Synthesis Unit (S-7616-33-0)	62		Added streams 18a and 18b to this permit unit, in the description as well as the table "Potential Fugitive Emissions for S-7616-33."
55	Urea Absorbers:	63		Global change: The urea HP and LP absorbers vents were combined into one Urea Absorber vent.
56	Ammonium Nitrate Unit (S-7616-36-0)	65	Annual operating hours	The annual operating hours have been increased to 8,052 hr/yr to match the operating schedule of the other equipment in the fertilizer complex.
57	Combustion Turbine Generator (S-7616-26-0)	68	Maximum hourly emissions during startup or shutdown tables	Please note that the emissions for the CTG/HRSG and feedstock dryer presented in these tables do not occur in the same hour.
58	Truck Unloading and Transfer System	75	Annual PE2 for S-7616-18-0 Table lists ACFM as 20,000.	Should be 80,000 acfm, same as in Daily PE2 for S7616-18-0. Emissions should be adjusted accordingly.
59	Feedstock Storage, Blending, and Reclaim System (S-7616-19-0)	76	Daily and Annual PE2 for S-7616-19-0 Tables.	Add fluxant emissions and operating parameters.
60	Gasification System (S-7616-21-0)	77	Potential Fugitive Emissions for S-7616-21 Table	Emissions include design refinements and new process streams 22 and 23.
61	Sulfur Recovery System's Tail Gas	80	Daily and Annual PE2 (S-7616-23-0) Tables	Added columns for emissions from the SRU Passivation

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	Thermal Oxidizer (S-7616-23-0)			and Presulfiding events.
62	CO_2 Recovery and Vent System (S-7616-24-0)	81	$PE2_{VOC}$ emission calculations	The VOC emissions are from methanol and benzene. Short-term emissions are based on 40 ppm methanol, 4 ppm benzene, and full venting rate. Long-term emissions are based on 20 ppm methanol at 85% of the full venting rate, and 4 ppm benzene at the full venting rate.
63	Cooling Towers (S-7616-27-0, -28-0, and -29-0):	82-83		$PM_{2.5}$ emission calculations are included for clarity for each cooling tower.
64	Cooling Towers	82	ASU Cooling Tower $PE(PM_{10})$ = 8.1 lb-PM_{10}/day	The TDS (lb/gallon) is wrong – based on 3,000 ppm instead of 2,000 ppm (see note for page 56) Correct value is 16.68 lb/1,000 gal $PE(PM_{10})$ = (0.000005)(16.68 lb/1,000 gal) (44,876 gal/min)(60 min/hr)(24hr/day) = 5.4 lb-PM_{10}/day = 1,867.0 lb-PM_{10}/yr
65	4,000 MMBtu/hr Gasification Flare (S-7616-30-0)	84	Daily and Annual Potential Emissions tables	Updated to reflect SO_X, PM_{10} and VOC syngas emission factors (instead of zero).
66	Ammonium Nitrate Unit (S-7616-36-0)	89	Annual PE2, 8,000 hr/yr	Annual hours of operation have been updated to 8,052 to be consistent with the rest of the fertilizer complex.
67	Post-Project Stationary Source Potential to Emit (SSPE2)	93	Post-Project Stationary Source Potential to Emit [SSPE2] Table	Table has been updated with revised numbers for all permit units and pollutants. The totals for each pollutant (lb/yr) have been carried through the rest of the document.
68	I. Significance of Project Emission Increase Determination for Each Attainment/ Unclassified Pollutant b. PSD Significant Emission Increase Determination For	97	Footnote 37. These emission increases are tabulated in Table 8-4 of the PSD application, which is found in Appendix F of this evaluation.	Table 8-4 is not in Appendix F.

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	Each Attainment/ Unclassified Pollutant			
			VIII Compliance	
69	3. Top-Down BACT Analysis Combustion Turbine Generator (S-7616-26-0)	112	NO_X: Selective catalytic reduction that does not exceed 2.5 ppmvd-NO_X @ 15% O_2 (1-hour average) when firing on hydrogen-rich fuel, except during startup/shutdown; and selective catalytic reduction that does not exceed 4.0 ppmvd-NO_X @ 15% O_2 (1-hour average) when firing on natural gas, except during startup/shutdown.	1-hour average should be changed to 3-hour average for 4.0 ppmvd-NO_X @ 15% O_2 when firing on natural gas.
70	3. Top-Down BACT Analysis S-7616-26-0 (Combustion Turbine Generator)	112	SO_X: PUC-regulated natural gas with no more than 0.75 grains-S/100 dscf, or 0.003 lb-SO_X/MMBtu when firing on hydrogen-rich fuel.	Change 0.003 to 0.0003 (as written in BACT guideline)
71	3. Top-Down BACT Analysis Railcar Unloading and Transfer System (S-7616-17-0) Truck Unloading and Transfer System (S-7616-18-0) Feedstock Grinding/ Crushing and Drying System (S-7616-20-0)	113	Petroleum coke handling: adequate moisture content of coke received, and loaded out, to prevent visible emissions in excess of 5% opacity. Water and surfactant applied to storage piles.	The feedstock will be stored in a barn, thus application of water or surfactant to control dust will not be necessary. Change to: "Petroleum coke handling: adequate moisture content of coke received, and loaded out, to prevent visible emissions in excess of 5% opacity."
72	S-7616-21-0 (Fugitive Emissions from Gasification System)	113	VOC: Leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. Leak defined as a reading of methane in excess of 500 ppmv above background for pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455.	Please remove this condition as it is not applicable to the HECA project, since there is negligible methane in any of the process streams.

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73	S-7616-23-0 (Fugitive Emissions from Sulfur Recovery System):	114	VOC: Leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455. Leak defined as a reading of methane in excess of 500 ppmv above background for pump and compressor seals when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455.	Please remove this condition as it is not applicable to the HECA project, since there is negligible methane in any of the process streams.
74	B. Offsets	116	(entire section)	Offsets calculations have been updated with revised total emissions for each pollutant. Also, the VOC offset ratio has been updated to 1.5:1, and the ERC certificate numbers for VOCs have been updated. Two VOC certificates will be surrendered, S-3305-1 and S-3557-1. Certificate S-3605-1 is not needed, thus will not be surrendered.
75	CO Offsets Required:	124	Ambient Modeling Results for CO Table	Modeled impact has been updated with most recent results. Further discussion of the modeling is provided in the updated air quality emissions and modeling report.
76	Global change to all material handling sources	128 (first occurrence)		Please remove all material handling conditions that limit daily and annual material handled, the remaining conditions will adequately limit PM emissions.
77	S-7616-23-0 (Sulfur Recovery and Tail Gas Compression System)	131		Add the SRU Passivation and Presulfiding events.
78	S-7616-30-0 (Gasification Flare)	133		Change PM_{10}, SO_X and VOC emission factors and emissions. Emissions will be negligible, but not zero.
79	S-7616-32-0 (Rectisol Flare)	133	Total time of planned flaring shall not exceed 8 hours per day nor 40 hours per calendar year.	Change to: "Maximum amount of gas combusted in the flare during shall not exceed 2,628 MMBtu/yr during pilot gas combustion nor 17,200 MMBtu/yr during other non-emergency combustion nor 3,440 MMBtu/day during other non-emergency combustion."
80	40 CFR 60 – Subpart	162-166		The time frame for compliance with 40 CFR 60 Subpart Ga

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
	Ga (Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011)			is a 30-day rolling average. All conditions and discussion should be based on this compliance time frame.
81	California Health & Safety Code 41700 (Health Risk Assessment)	177	HRA Summary Table	Please note that the values presented in this table do not match the recent modeling. Please update the Cancer Risk values. Further discussion of the modeling is provided in the updated air quality emissions and modeling report.
82	Rule 4311 – Flares	190-201	According to the application, the flare gas pressure of the gasification flare (S-7616-30) will be greater than or equal to 5 psig; therefore the requirements of Section 5.6 and 40 CFR 60.18 do not apply to flare S-7616-30. Flare gas pressure shall not be less than 5 psig when incinerating combustible gasses. [District Rule 4311, 5.6]	The gasification flare has an open flare tip, thus the pressure will be less than 5 psig and 40 CFR 60.18 will apply to this flare. This condition has been removed, as 40 CFR 60.18 will apply to the gasification flare. Language and conditions have been updated accordingly.
83	Rule 4311 – Flares	200-201	5 conditions	The conditions presented are not necessary since they are requirements of 40 CFR 60.18, and there is condition stating the flares will comply with 40 CFR 60.18.
84	S-7616-40-0 (Emergency Engine Powering Firewater Pump)	220	Requirements of Title 13 CCR, Section 2423 Table • {edited 3486} Emissions from this IC engine shall not exceed 0.01 g-PM_{10}/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]	Interim Tier 4 and Tier 4 standards are 0.015 g-PM_{10}/bhp-hr, thus changed the limit bullet and table accordingly.
85	PM Emissions and Hours of Operation Requirements for New Diesel Engine (S-7616-40-0):	224	1. Emits diesel PM at a rate less than or equal to 0.01 g/bhp-hr; • {edited 3486} Emissions from this IC engine shall not exceed 0.01 g-PM_{10}/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]	Interim Tier 4 and Tier 4 standards are 0.015 g-PM_{10}/bhp-hr, thus changed the 2 bullets accordingly.
IX Recommendation				

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86	No comments			
			X Billing Information	
87	No comments			
Appendix A – Determination of Compliance Conditions				
88	Global Change	All permit units		Offsets calculations have been updated with correct total emissions for each pollutant. Also, the VOC offset ratio has been updated to 1.5:1, and the ERC certificate numbers for VOCs have been updated.
89	Global Change	Permit Unit S-7616-17-0 A-1 Condition 5 (first occurrence)	Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40-32, -33, -34, -36, -37, -38, -39, and -40,	Please delete the duplicated unit numbers "-32, -33, -34, -36, -37, -38, -39, and -40"
90	Global change to all material handling sources	Permit Unit S-7616-17-0 A-2 Condition 20 (first occurrence)	20. Airflow for the following dust collector(s) shall not exceed: rail unloading station: 20,000 cfm. [District Rule 2201]	Please change all material handling conditions that limit fan size. Change "Airflow for the following dust collector(s) shall not exceed:" to "Airflow for the following dust collector(s) shall not exceed the name plate capacity:"
91	Global change to all material handling sources	Permit Unit S-7616-17-0 A-3 Conditions 24 and 25 (first occurrence)	24. The maximum process rates of material on a weight basis shall not exceed any of the following: rail unloading station: 6,107 ton/day. [District Rule 2201] 25. The maximum process rates of material on a weight basis shall not exceed any of the following: rail unloading station: 396,955 ton/yr. [District Rule 2201]	Please remove all material handling conditions that limit daily and annual material handled, the remaining conditions will adequately limit PM emissions.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
92	Global change to all sources with fugitive emissions	Permit Unit S-7616-21-0 A-23 Condition 19 (first occurrence)		The HECA project will have negligible VOC in any of the process streams. Please change all references to requiring Method 21 testing to require "Method 21 testing or equivalent test method with prior District approval"
93	Permit Unit S-7616-19-0	A-11 Permit unit description	FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS	It has been determined that fluxant will be needed to increase the calcium content of the feedstock to achieve vitreous "glass like" gasification solids. Add fluxant to the unit description, change to "FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS, FLUXANT SILO AND UNLOADING VENT SERVED BY A DUST COLLECTOR"
94	Permit Unit S-7616-19-0	A-12 Condition 8	8. Operation shall include the following dust collectors serving the following operation(s): feedstock transfer tower 1; feedstock transfer tower 2 [District Rule 2201]	Please change the condition to include the fluxant unloading vent. Change to "Operation shall include the following dust collectors serving the following operation(s): feedstock transfer tower 1; feedstock transfer tower 2; fluxant unloading vent [District Rule 2201]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
95	Permit Unit S-7616-19-0	A-12 Condition 18	18. Airflow for the following dust collector(s) shall not exceed the name plate capacity: feedstock transfer tower 1: 1,500 cfm; feedstock transfer tower 2: 1,500 cfm. [District Rule 2201]	Please change the condition to include the fluxant unloading vent. Change to "Airflow for the following dust collector(s) shall not exceed the name plate capacity: feedstock transfer tower 1: 1,500 cfm; feedstock transfer tower 2: 1,500 cfm; fluxant unloading vent: 1,500 cfm."
96	Permit Unit S-7616-19-0	A-12 Condition 20	20. PM_{10} emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 0.3 lb/day; feedstock transfer tower 2: 0.3 lb/day. [District Rule 2201]	Please change the condition to include the fluxant unloading vent. Change to "PM_{10} emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 0.3 lb/day; feedstock transfer tower 2: 0.3 lb/day; fluxant unloading vent: 0.3 lb/day."
97	Permit Unit S-7616-19-0	A-12 Condition 21	21. PM_{10} emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 40 lb/yr; feedstock transfer tower 2: 56 lb/yr. [District Rule 2201]	Please change the condition to include the fluxant unloading vent. Change to "PM_{10} emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 40 lb/yr; feedstock transfer tower 2: 56 lb/yr; fluxant unloading vent: 28 lb/yr."
98	Permit Unit S-7616-21-0	A-21 Permit unit description	GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, AND RECTISOL ACID GAS REMOVAL (AGR) UNIT	Add methanol tank to the unit description Change to "GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, RECTISOL ACID GAS REMOVAL (AGR) UNIT, AND METHANOL STORAGE TANK"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
99	Permit Unit S-7616-21-0	A-21 Condition 8	Components attributed to this unit shall include those components serving the following process streams: methanol, syngas, shifted syngas, propylene, sour water, H_2S-laden methanol, CO_2-laden methanol, acid gas, and ammonia-laden gas.	Please change the condition to include two new fugitive streams (#22 and #23): Components attributed to this unit shall include those components serving the following process streams: methanol, syngas, shifted syngas, propylene, sour water, H_2S-laden methanol, CO_2-laden methanol, acid gas, ammonia-laden gas, lower benzene concentration and higher benzene concentration.
100	Permit Unit S-7616-21-0	A-22 Condition 13	13. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]	Please consider removing this condition or changing to: Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan will be developed and submitted to the District for approval to determine sampling frequency and locations. [District Rule 2201]
101	Permit Unit S-7616-21-0	A-24 Condition 25	25. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]	Please change the response time to four hours instead of one hour: An operator shall minimize all component leaks immediately to the extent possible, but not later than four (4) hours after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]
102	Permit Unit S-7616-21-0	A-24 Condition 30	30. Sampling ports adequate for extraction of grab samples and measurement of gas flow rate shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]	Change to: "Sampling points adequate for extraction of grab samples shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]"

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103	Permit Unit S-7616-22-0	A-29 Conditions 23-26	23. Moisture content of the solids stacking material shall be maintained at 12% or greater, by weight, and moisture content of solids reclaim material shall be maintained at 8% or greater, by weight. [District Rule 2201] 24. The percent moisture the solids stacking material and the solids reclaim material shall be determined by weighing an approximately 2-lb sample of each material from in the material handling area, bringing the sample to dryness in a drying oven, then weighing the dried sample; the weight difference divided by the initial weigh of the sample; all multiply by 100% is the moisture content (% moisture = ((initial weight – dry weight)/initial weight) x 100%). [District Rule 2201] 25. Moisture content of the solids stacking material and the solids reclaim material shall be measured on monthly basis and when requested by the District. [District Rule 2201] 26. Records of monthly moisture content of the solids stacking material and the solids reclaim material shall be maintained, retained on-site for a period of at least five (5) years and made available for District inspection upon. [District Rule 2201]	Please remove these four conditions; they are onerous for a source that has only 0.06 ton/yr of particulate matter. Condition 28 shall ensure that emissions are minimized.
104	Permit Unit S-7616-23-0		General	The TGTO will also be used to dispose of sulfur bearing waste gas during intermittent post-shutdown SRU passivation and presulfiding of the tail gas hydrogenation catalyst. Each operation is expected to occur no more than once per year, for 24 hours each. Thus up to 48 hours per year of additional usage of the thermal oxidizer for these shutdown events is needed and has been added to the conditions.
105	Permit Unit S-7616-23-0	A-34 Condition 13	13. The operation shall include continuously recording H_2S monitor for incinerator inlet (on the TGU absorber overhead) and incinerator with continuously recording SO_2 and O_2 monitors. [District Rule 2201]	Note that there is no TGU absorber since the tail gas is recycled to the Shift Unit, thus please change to "The operation of the thermal oxidizer shall include continuously recording SO_2 and O_2 monitors. [District Rule 2201]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
106	Permit Unit S-7616-23-0	A-35 Condition 21	21. Startup is defined as the period beginning with the introduction (or increased utilization) of natural gas to the SRU to raise the temperature of the catalytic reactors to operating temperature (approximately 350 degrees F). Startup ends when the concentration of H_2S in the TGU absorber offgas does not exceed 10 ppmv (moving 3-hour average). [District Rule 2201]	Please change to: "Startup is defined as the period beginning with the introduction (or increased utilization) of natural gas to the SRU to raise the temperature of the reactor furnace and catalytic reactors to normal operating temperature (approximately 350 degrees F). Startup ends when the SRU is processing all acid gas and sour gas feeds and the desired tail gas H_2S: SO_2 ratio has stabilized, and the TGU off-gas is recycled back to the Shift unit. [District Rule 2201]"
107	Permit Unit S-7616-23-0	A-35 Condition 22	22. Except during shutdown, warm standby, startup, and breakdown (as defined in Rule 1100) conditions, concentration of H_2S in the TGU absorber offgas when feeding the TGU incinerator shall not exceed 10 ppmv H_2S (moving 3-hour average). [District Rule 2201]	Please change to: "Except during shutdown, warm standby, startup, and breakdown (as defined in Rule 1100) conditions, TGU tail gas shall be recycled to the Shift unit, and the Thermal Oxidizer will be maintained in hot standby. [District Rule 2201]"
108	Permit Unit S-7616-23-0	A-35 Condition 26	26. SO_X (as SO_2) emissions from the tail gas thermal oxidizer shall not exceed 0.0204 lb/MMBtu for the disposal of SRU startup gas nor 2.00 lb/hr for the disposal of the process vent gas. [District Rule 2201]	Please change to account for the SRU maintenance events (Passivation and Presulfiding): "SO_X (as SO_2) emissions from the tail gas thermal oxidizer shall not exceed 0.00204 lb/MMBtu for the disposal of SRU startup gas nor 2.0 lb/hr for the disposal of the process vent gas nor 75 lb/hr during plant shutdown for passivation nor 125 lb/hr for presulfiding of catalyst. [District Rule 2201]"
109	Permit Unit S-7616-23-0	A-35 Condition 28	28. The thermal oxidizer firing rate shall not exceed 13.0 MMBtu/hr of natural gas from normal operation (for the disposal of process vent gas). The thermal oxidizer firing rate shall not exceed 80.0 MMBtu/hr of natural gas from SRU startup operation (for the disposal of SRU startup gas). [District Rule 2201]	Please change to: The thermal oxidizer firing rate shall not exceed 13.0 MMBtu/hr (HHV) of natural gas from normal operation (for the disposal of process vent gas). Pre-startup firing of natural gas in the SRU reactor furnace for system warmup, with the products of combustion vented to the thermal oxidizer, shall not exceed 80.0 MMBtu/hr (HHV). Likewise, post-shutdown firing of natural gas in the SRU for plant maintenance shall not exceed 80.0 MMBtu/hr (HHV). [District Rule 2201]

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
110	Permit Unit S-7616-23-0	A-35 Condition 29	29. The thermal oxidizer shall not exceed 8,314 hours per calendar year of normal operation (for the disposal of process vent gas) nor 48 hours per calendar year of SRU startup operation (for the disposal of SRU startup gas). [District Rules 2201 and 2410]	Please change the limits to be based on heat input not hours, although these equate to the same emissions. Change to "The thermal oxidizer shall not exceed 108,082 MMBtu for normal operation (for the disposal of process vent gas) per calendar year nor 3,840 MMBtu per calendar year for SRU startup operation (for the disposal of SRU startup gas) nor 1,920 MMBtu per calendar year for SRU maintenance. [District Rules 2201 and 2410]"
111	Permit Unit S-7616-23-0	A-36 Condition 33	33. During SRU shutdown, SRU tail gas shall be directed to the TGU provided the O_2 content of the SRU tail gas is less than or equal to 0.5% by weight as measured with portable O_2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer. During such periods, SRU tail gas shall be directed to the TGU. During the final 12 hours of SRU shutdown, the SRU tail gas may bypass the TGU and be introduced directly to the incinerator. [District Rule 2201]	Please change to: 33. During SRU shutdown, SRU tail gas shall be directed to the TGU provided the O_2 content of the SRU tail gas is less than or equal to 0.5% by weight as measured with portable O_2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer, provided the exotherm across the TGU catalytic reactor does not become excessive. During the final 12 hours of SRU shutdown, or should the TGU catalytic reactor temperature rise above 750 degrees Fahrenheit, the SRU tail gas may bypass the TGU and be introduced directly to the Thermal Oxidizer. [District Rule 2201]
112	Permit Unit S-7616-23-0	A-37 Condition 45	45. For the sulfur recovery unit, a continuous emissions monitoring system shall be installed, calibrated, operated, and reported. Operator shall report all 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system exceeds 10 ppm (dry basis, zero percent excess air). [District Rule 2201]	Because the SRU tail gas will be hydrogenated and recycled to syngas treating, no H_2S-containing streams will normally be fed to the Thermal Oxidizer, thus HECA requests this condition be removed.
113	Permit Unit S-7616-23-0	A-37 Condition 52	52. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]	Please consider removing this condition or changing to: "Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan will be developed and submitted to the District for approval to determine sampling frequency and locations."

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114	Permit Unit S-7616-23-0	A-38 Condition 56	56. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]	Please remove this condition as it is not applicable to the HECA project, since there is negligible methane in any of the process streams.
115	Permit Unit S-7616-23-0	A-39 Condition 64	64. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]	Change from 1 hour to 4 hours. "An operator shall minimize all component leaks immediately to the extent possible, but not later than four (4) hours after detection of leaks in order to stop or reduce leakage to the atmosphere."
116	Permit Unit S-7616-24-0	A-42 Condition 10	10. Venting shall not exceed 504 hours per rolling 12-month period. [District Rules 2201 and 2410]	Change to "Venting shall not exceed 193,394 ton/yr CO_2 per rolling 12-month period. [District Rules 2201 and 2410]"
117	Permit Unit S-7616-26-0	A-53 Permit unit description	431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI 501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), AND A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE	Change Permit unit description to "431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI M501 GAC G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), AND A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE AND FEEDSTOCK DRYER (WITH DRYING GAS FROM TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR)"

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118	Permit Unit S-7616-26-0	A-55-56 Condition 23	23. The total mass emissions of NO_X, SO_X, PM_{10}, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in this document. NO_X and CO total mass emissions will be determined from CEMs data and SO_X, PM_{10}, and VOC total mass emissions will be calculated. [District Rule 2201]	During commissioning CTG/HRSG and feedstock dryer CO emissions will be higher than during normal operations. Change to: "The total mass emissions of NO_X, SO_X, PM_{10}, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in this document. NO_X total mass emissions will be determined from CEMs data and SO_X, PM_{10}, and VOC total mass emissions will be calculated. [District Rule 2201]"
119	Permit Unit S-7616-26-0	A-56 New Condition 23a	New Condition 23a	During commissioning CTG/HRSG and feedstock dryer CO emissions will be higher than during normal operations. To ensure compliance with the commissioning emissions presented in the ATC application and in the PDOC, add the following new condition. "The total mass emissions of CO that are emitted from the CTG/HRSG stack during the commissioning period shall not exceed 332.1 tons. CO total mass emissions will be determined from CEMs data. [District Rule 2201]"
120	Permit Unit S-7616-26-0	A-56 Condition 24	24. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction.	Remove "Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst." There is no inlet air blower.

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121	Permit Unit S-7616-26-0	A-56 Condition 29	29. This unit shall be fired on hydrogen-rich fuel or on PUC-regulated natural gas backup fuel. Firing on backup PUC-quality natural gas shall only occur during CTG startups (with firing on natural gas not to exceed 5 total hours per calendar year), CTG shutdowns (with firing on natural gas not to exceed 10 hours per calendar year), or during periods of unplanned equipment outages (with firing on natural gas not to exceed 336 hours per calendar year). [District Rule 2201 and 2410]	Remove "(with firing on natural gas not to exceed 5 total hours per calendar year)" and "(with firing on natural gas not to exceed 10 hours per calendar year)"
122	Permit Unit S-7616-26-0	A-57 Condition 34	34. Ammonia (NH_3) emissions shall not exceed either of the following limits: 18.50 lb/hr or 5.0 ppmvd @ 15% O_2 (based on a 24 hour rolling average).	Change to "Ammonia (NH_3) emissions from the CTG/HRSG stack shall not exceed either of the following limits when firing on natural gas or hydrogen-rich fuel: 18.50 lb/hr or 5.0 ppmvd @ 15% O_2 (based on a 24 hour rolling average) nor ammonia (NH_3) emissions from the feedstock dryer stack shall not exceed either of the following limits: 3.2 lb/hr or 5.0 ppmvd @ 15% O_2 (based on a 24 hour rolling average)."
123	Permit Unit S-7616-26-0	A-58 Condition 41	41. CTG/HRSG and feedstock dryer shall each be limited to two startups and two shutdowns per calendar year. [District Rule 2201]	Please remove this condition. Annual emission limitations will adequately limit these emissions.
124	Permit Unit S-7616-26-0	A-61 Condition 65	65. CEMS shall continuously measure and record the parameters required in the condition above for both the CTG/HRSG exhaust and the feedstock dryer exhaust. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]	Change to "One CEMS shall continuously measure and record the parameters required in the condition above for both the CTG/HRSG exhaust and the feedstock dryer exhaust."
125	Permit Unit S-7616-26-0	A-63 Condition 81	81. Sampling ports adequate for extraction of grab samples and measurement of gas flow rate shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]	Please remove this condition as it is identical the Unit S-7616-21-0 Condition 30.

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126	Permit Unit S-7616-26-0	A-63 Condition 82	82. Operator shall monitor the syngas flow rate and the CO, CO_2, and CH_4 concentration in the gas upstream and downstream of the acid gas removal (AGR) unit using laboratory sample analysis at least once every month. [District Rules 1081 and 2410]	Change to: "Operator shall monitor the syngas flow rate and the CO, CO_2, and CH_4 concentration in the gas upstream and downstream of the acid gas removal (AGR) unit using an analytical process gas measurement systems approved by the District at least once every month. [District Rules 1081 and 2410]"
127	Permit Unit S-7616-26-0	A-63 Condition 83	83. Compliance with the 90 percent (by weight) reduction in the pre-combustion carbon content in the gasified fuel stream shall be demonstrated by the results of the laboratory sample analysis and flow rates once every month. [District Rules 1081 and 2410]	Change to: "Compliance with the 90 percent (annual average by weight) reduction in the pre-combustion carbon content in the gasified fuel stream shall be demonstrated by the monitoring results of the analytical process gas measurement system [District Rules 1081 and 2410]"
128	Permit Unit S-7616-26-0	A-63 Condition 86	86. The permittee shall demonstrate compliance with the emission performance standard of 400 lb/MWh using the calculation methodology established by SB 1368 (Greenhouse Gases Emission Performance Standard) for each calendar month. The permittee shall calculate the facility's emission performance value and maintain records of this value. [District Rule 2410]	Please consider removing condition or changing to "The permittee shall demonstrate compliance with the emission performance standard established by SB 1368 (Greenhouse Gases Emission Performance Standard) for a rolling 12-month period. The permittee shall calculate the facility's emission performance value and maintain records of this value. [District Rule 2410]" CEC is still determining which emissions need to be included in the EPS calculation, thus the performance of HECA may appear different due to these calculations. HECA will comply with the EPS set forth in SB1368.
129	Permit Unit S-7616-26-0	A-63 Condition 87	87. CO2e emissions from entire stationary source (S-7616) shall not exceed 595,917 tons per calendar year. The permittee shall calculate the CO2e emissions for each calendar month and shall maintain such records onsite for District review. [District Rule 2410]	Per the request of EPA, HECA suggests changing the compliance period from annual to a rolling 12-month period. Change condition to: "CO2e emissions from entire stationary source (S-7616) shall not exceed 595,048 tons per rolling 12-month period. The permittee shall calculate the CO2e emissions for each calendar month and shall maintain such records onsite for District review. [District Rule 2410]"

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130	Permit Unit S-7616-27-0	A-67 Condition 17	17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained.	Since a flow meter is not practical, please change the condition to: "Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps."
131	Permit Unit S-7616-28-0	A-71 Condition 17	17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained.	Since a flow meter is not practical, please change the condition to: "Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps."
132	Permit Unit S-7616-29-0	A-75 Condition 17	17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained.	Since a flow meter is not practical, please change the condition to: "Operator shall monitor and record the design circulation water flow rate associated with the operation of the cooling tower basin pumps."
133	Permit Unit S-7616-30-0	A-79 New Condition 10a	New Condition 10a	During commissioning emissions will be higher than during normal operations. To ensure compliance with the commissioning emissions presented in the ATC application, add the following new condition. "During the commissioning period, emission rates from the flare shall not exceed any of the following limits: NO_X (as NO_2) – 50 tons; SO_X – 1.4 tons; PM_{10} – 0.2 ton; CO – 523 tons; or VOC – 0.1 ton. [District Rule 2201]"
134	Permit Unit S-7616-30-0	A-80 Condition 19	19. Maximum amount of gas combusted in the flare during planned flaring shall not exceed any of the following: 21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; 43,434 MMBtu/yr of shifted gas. [District Rules 2201 and 2410]	Change to: "Maximum amount of gas combusted in the flare during planned flaring shall not exceed any of the following: 21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; 43,434 MMBtu/yr of shifted gas, except during commissioning. [District Rules 2201 and 2410]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
135	Permit Unit S-7616-30-0	A-80 Condition 21	21. Emissions from the flare, during the non-emergency combustion of syngas and waste gas, shall not exceed any of the following (based on total gas combusted): PM_{10}: 0.000 lb/MMBtu; NO_X (as NO_2): 0.068 lb/MMBtu; VOC: 0.000 lb/MMBtu; CO: 2.0 lb/MMBtu on unshifted syngas and 0.37 lb/MMBtu on shifted syngas; or SO_X: 0.000 lb/MMBtu. [District Rule 2201]	Emissions of PM_{10}, VOC and SO_X will be negligible from this flare, but may not be zero. Please change the condition to use the syngas emission factors from the turbine, as this represents the maximum these emissions could be. Change to "Emissions from the flare, during the non-emergency combustion of syngas and waste gas, shall not exceed any of the following (based on total gas combusted): PM_{10}: 0.008 lb/MMBtu; NO_X (as NO_2): 0.068 lb/MMBtu; VOC: 0.0015 lb/MMBtu; CO: 2.0 lb/MMBtu on unshifted syngas and 0.37 lb/MMBtu on shifted syngas; or SO_X: 0.002 lb/MMBtu"
136	Permit Unit S-7616-30-0	A-80 Condition 23	23. Emissions from the flare shall not exceed any of the following: NO_X: 2,399.0 lb/day; SO_X: 18.8 lb/day; PM_{10}: 26.4 lb/day; CO: 20,335.2 lb/day; or VOC: 11.4 lb/day. [District Rule 2201]	Change to: "Emissions from planned flaring shall not exceed any of the following: NO_X: 2,399.0 lb/day; SO_X: 79.7 lb/day; PM_{10}: 238.2 lb/day; CO: 18,282 lb/day; or VOC: 51.2 lb/day, except during commissioning. [District Rule 2201]"
137	Permit Unit S-7616-30-0	A-81 Condition 29	29. Flare gas pressure shall not be less than 5 psig when incinerating combustible gasses. [District Rule 4311, 5.6]	Please remove and replace with the same conditions as for the SRU and Rectisol flares to meet the requirements of 40 CFR 60.18. Change to: "Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
138	Permit Unit S-7616-30-0	A-82 Condition 41	41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]	Please remove; this requirement is already covered by Condition 31. If condition is not removed change the notification requirements to 24 hours.
139	Permit Unit S-7616-31-0	A-85 Permit unit description	800 MMBTU/HR ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)	Please change to: 2,100 MMBTU/HR (LHV) ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)
140	Permit Unit S-7616-31-0	A-86 Condition 19	19. Total time of planned flaring shall not exceed 40 hours per calendar year. [District Rule 2201 and 2410]	Change to "Maximum amount of gas combusted in the flare during shall not exceed 2,628 MMBtu/yr during pilot gas combustion nor 1,440 MMBtu/yr during other non-emergency combustion." The emissions and limitation are exactly the same, HECA just requests the limitation on amount of gas flared.
141	Permit Unit S-7616-31-0	A-87 Condition 20	20. During planned flaring events, no more than 36 MMBtu/hr shall be combusted, plus pilot gas of 0.3 MMBtu/hr. [District Rules 2201 and 2410]	Change to "During planned flaring events, no more than 36 MMBtu/hr shall be combusted, plus pilot gas of 0.3 MMBtu/hr."

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
142	Permit Unit S-7616-31-0	A-89 Condition 41	41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]	Please remove; this requirement is already covered by Condition 31. If condition is not removed change the notification requirements to 24 hours.
143	Permit Unit S-7616-31-0	A-89 Condition 43	43. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]	Change to: "Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]"
144	Permit Unit S-7616-31-0	A-90 Conditions 45-49		Please remove Conditions 45-49, since Condition 43 adequately addresses all of the compliance requirements of 40 CFR 60.18.
145	Permit Unit S-7616-32-0	A-94 Condition 19	19. Total time of planned flaring shall not exceed 8 hours per day nor 40 hours per calendar year. [District Rules 2201 and 2410]	Change to "Maximum amount of gas combusted in the flare during shall not exceed 2,628 MMBtu/yr during pilot gas combustion nor 17,200 MMBtu/yr during other non-emergency combustion nor 3,440 MMBtu/day during other non-emergency combustion." The emissions and limitation are exactly the same, HECA just requests the limitation on amount of gas flared.
146	Permit Unit S-7616-32-0	A-95 Condition 20	20. During planned flaring events, no more than 430 MMBtu/hr shall be combusted. [District Rule 2201 and 2410]	Change to "During planned flaring events, no more than 430 MMBtu/hr shall be combusted plus pilot gas of 0.3 MMBtu/hr."

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
147	Permit Unit S-7616-32-0	A-97 Condition 41	41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]	Please remove; this requirement is already covered by Condition 31. If condition is not removed change the notification requirements to 24 hours.
148	Permit Unit S-7616-32-0	A-97 Condition 43	43. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]	Change to: "Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be designed and operated in accordance with 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]"
149	Permit Unit S-7616-32-0	A-98 Conditions 45-49		Please remove Conditions 45-49, since Condition 43 adequately addresses all of the compliance requirements of 40 CFR 60.18.
150	Permit Unit S-7616-33-0	A-105 Condition 37	37. Components attributed to this unit shall include those components serving the following process streams: low NH_3 concentration, moderate NH_3 concentration, high NH_3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO_3), and PSA off gas. [District Rule 2201]	Two additional fugitive streams were added to this permit unit. Please change to: "Components attributed to this unit shall include those components serving the following process streams: low NH_3 concentration, moderate NH_3 concentration, high NH_3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO_3), PSA off gas, CO_2 product and purification compressors and urea CO_2 compressor. [District Rule 2201]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
151	Permit Unit S-7616-33-0	A-106 Condition 41	41. The VOC content of the gas in the following streams shall not exceed 10% by weight: low NH_3 concentration, moderate NH_3 concentration, high NH_3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO_3), and PSA off gas. [District Rule 2201]	Please change to: 41. The VOC content of the gas in the following streams shall not exceed 10% by weight: low NH_3 concentration, moderate NH_3 concentration, high NH_3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO_3), PSA off gas, CO_2 product and purification compressors and urea CO_2 compressor. [District Rule 2201]
152	Permit Unit S-7616-33-0	A-106 Condition 42	42. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]	Please consider removing this condition or changing to: "Operator shall conduct gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. A Fugitive Emissions Monitoring Plan will be developed and submitted to the District for approval to determine sampling frequency and locations."
153	Permit Unit S-7616-33-0	A-106 Condition 46	46. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]	Please remove this condition as it is not applicable to the HECA project, since there is negligible methane in any of the process streams.
154	Permit Unit S-7616-33-0	A-108 Condition 54	54. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]	Please change the response time to four hours instead of one hour: An operator shall minimize all component leaks immediately to the extent possible, but not later than four (4) hours after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
155	Permit Unit S-7616-34-0	A-111 Permit unit description	UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR	Change Permit unit description to "UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS VENTED TO THE UREA ABSORBER VENT; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR"
156	Permit Unit S-7616-35-0	A-117 New Condition 9a	New Condition 9a	During commissioning daily NO_X emissions will be higher than during normal operations. To ensure compliance with the commissioning emissions presented in the ATC application, add the following new condition. "During the commissioning period the NO_X emission rate shall not exceed 504 lb/day. [District Rule 2201]"
157	Permit Unit S-7616-35-0	A-117 Condition 10	10. The production rate of nitric acid shall not exceed 501 tons of nitric acid in one day. [District Rule 2201]	Change to: "The production rate of nitric acid shall not exceed 168,086 tons of nitric acid (100% basis) per year."
158	Permit Unit S-7616-35-0	A-117 Condition 12	12. NO_X emissions from the nitric acid unit shall not exceed 100.2 lb-NO_X/day, except during commissioning. [District Rule 2201]	Change to: "NO_X emissions from the nitric acid unit shall not exceed 100.2 lb-NO_X/day, except during commissioning. [District Rule 2201]"
159	Permit Unit S-7616-35-0	A-117 Condition 15	15. N_2O emission rate shall not exceed 0.54 lb-N_2O per ton of HNO_3 produced. [District Rule 2410]	Change to: "N_2O emission rate shall not exceed 0.54 lb-N_2O per ton of HNO_3 produced (based on an annual average). [District Rule 2410]"
160	Permit Unit S-7616-35-0	A-117-119 Conditions 20, 31, 32		The time frame for compliance with 40 CFR 60 Subpart Ga is a 30-day rolling average. Change the compliance periods to a 30-day rolling average.
161	Permit Unit S-7616-36-0	A-124 Condition 12	12. PM_{10} emission from scrubber vent shall not exceed 0.0075 lb-PM_{10} per ton of ammonium nitrate produced. [District Rule 2201]	Please change to: "PM_{10} emission from scrubber vent shall not exceed 1,610 lb-PM_{10} per year. [District Rule 2201]"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
162	Permit Unit S-7616-36-0	A-124 Condition 13	13. Production of ammonium nitrate shall not exceed 636 tons per day nor 212,000 tons during any consecutive 12-month period. [District Rule 2201]	Please change to: "Production of ammonium nitrate shall not exceed 232,140 tons during any consecutive 12-month period. [District Rule 2201]"
163	Permit Unit S-7616-36-0	A-124 Condition 14	14. Operation of the ammonium nitrate unit shall not exceed 8,000 hours per calendar year. [District Rule 2201]	Please remove this condition as the remaining conditions will adequately limit PM emissions.
164	Permit Unit S-7616-37-0	A-129 Condition 20	20. PM_{10} emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 113 lb/yr; urea transfer tower 2: 28 lb/yr; urea transfer tower 3: 56 lb/yr; urea transfer tower 4: 28 lb/yr; urea transfer tower 5: 27 lb/yr; urea loading building baghouse: 357 lb/yr. [District Rule 2201]	Please change to: 20. PM_{10} emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 113 lb/yr; for the combined urea transfer towers 2, 3, and 4: 113 lb/yr;; urea transfer tower 5: 27 lb/yr; urea loading building baghouse: 357 lb/yr. [District Rule 2201]
165	Permit Units S-7616-38, -39 and -40	A-133 Permit unit description (first occurrence)	2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING APPLICABLE AT THE TIME OF INSTALLATION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #1 (OR EQUIVALENT)	Please change emergency engine descriptions and conditions to reflect the highest tier rating applicable at the time of purchase instead of installation: 2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING APPLICABLE AT THE TIME OF PURCHASE, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #1 (OR EQUIVALENT)
Appendix B– BACT Guidelines				
166	Emission unit: Combustion Turbine Generator	13th page of Appendix B	SOx achieved in practice or contained in SIP: …0.0003 lb-SOx/MMBtu when firing on H2-rich fuel exclusively.	Change to be consistent with BACT analysis in Appendix C: …0.003 lb-SOx/MMBtu when firing on H2-rich fuel exclusively.
167	Emission unit: Coal/coke gasification CO_2 recovery	14th page of Appendix B	Technologically feasible control for both CO and VOC "up to 504 hours per rolling 12-month period."	Change to "up to 200,000 ton/yr CO_2 per rolling 12-month period."

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
168	Emission unit: Nitric acid unit	15th page of Appendix B	Equipment rating: up to 501 tons of nitric acid produced per day (expressed as 100 percent nitric acid)	Please remove the production rate of "501 tons of nitric acid produced per day"
169	Emission unit: Nitric acid unit	15th page of Appendix B	Achieved in Practice and Technologically Feasible limits	The time frame for compliance with 40 CFR 60 Subpart Ga is a 30-day rolling average. Change both the Achieved in Practice and Technologically Feasible compliance periods to a 30-day rolling average.
170	Emission unit: Ammonium nitrate unit	16th page of Appendix B	Equipment rating: up to 636 tons per day of ammonium nitrate solution produced	Please remove the production rate of "636 tons per day of ammonium nitrate solution produced"
Appendix C – Top Down BACT Analyses				
171	Top Down BACT Analysis for the CO_2 Recovery System (S-7616-24)	C-17	General for this unit (in 4 places)	Change "504 hr" to "193,394 ton CO_2" for unit limitation
172	Top Down BACT Analysis for the Nitric Acid Plant (S-7616-35)	C-35	General for this unit	The time frame for compliance with 40 CFR 60 Subpart Ga is a 30-day rolling average. Change the compliance periods in the technologies to a 30-day rolling average.
Appendix D – Process Flow Diagrams				
173	No comments			
Appendix E – Fugitive Emission Calculations				
174	General comment			Fugitive emissions have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments.
Appendix F – Emission Information				
175	General comment			Please rename appendix "CTG/HRSG and Feedstock Dyer Emission Information"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
176		2nd page of Appendix F	Table 3-5	CTG/HRSG Startup Step 3 duration needs to change from 50 hours to 2 hours. Emissions need to change to match those presented in Section VII General Calculations.
177		2nd page of Appendix F	Table 3-5	Feedstock Drying Startup Step 3 duration needs to change from 50 hours to 2 hours. Emissions need to change to match those presented in Section VII General Calculations.
Appendix G – Calculation Methodology for General Conformity Mitigation Agreement				
178		2nd page of Appendix G		Please replace the calculations with those presented in Mitigation Agreement agreed to with SJVAPCD and presented in the updated air quality emissions and modeling report submitted with these comments.
Appendix H – Hazardous Air Pollutant Summary				
179	General comment			HAP emissions have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments.
Appendix I – Greenhouse Gas BACT Analysis				
180	Appendix I Section I. Proposal	2	Table 1	CO_2e emissions have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments. The updated emissions have also been included in Table 1.
181	Appendix I Section B. Project Purpose and Design	6	Figure	Hatching was added to the figure to make it more clear when printed in black and white.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
182	Appendix I Section C. Overview of Emissions	8	Although such standard is not a SJVAPCD requirement, in order to help demonstrate compliance with GHG BACT requirements, section V.A of the evaluation will limit CO_2 emission to 400 lb-CO_2/MWh for the combustion turbine generator as one of the various requirements to demonstrate with the GHG BACT.	Please change the language to "Although such standard is not a SJVAPCD requirement, in order to help demonstrate compliance with GHG BACT requirements, section V.A of the evaluation will limit CO_2 emission to 1,100 lb-CO_2/MWh for the combustion turbine generator. Although the project was assessed on emissions no higher than 400 lb-CO_2/MWh (based on the calculations presented in Table 2) for the combustion turbine generator as one of the various requirements to demonstrate with the GHG BACT" CEC is still determining which emissions need to be included in the EPS calculation, thus the performance of HECA may appear different due to these calculations. HECA will comply with the EPS set forth in SB1368.
183	Appendix I Section V. Top Down BACT Analysis A. Top Down BACT Analysis for Combined Cycle Power Generation System	24	Emissions from the low-carbon fuel used in the CTG/HRSG shall also be demonstrated through compliance with SB 1368 (Greenhouse Gases Emission Performance Standard), whereby HECA will calculate the CO_2 emissions per MWh from power production to compare against the Emission Performance Standards of 1,100 lb/MWh. The maximum CO_2 power-related emissions, based on the SB 1368 calculation methodology, will be limited to 400 lb/MWh.	Please change the language to "Emissions from the low-carbon fuel used in the CTG/HRSG shall also be demonstrated through compliance with SB 1368 (Greenhouse Gases Emission Performance Standard), whereby HECA will calculate the CO_2 emissions per MWh from power production to compare against the Emission Performance Standards of 1,100 lb/MWh. The maximum CO_2 power-related emissions, based on the SB 1368 calculation methodology, will be limited to 1,100 lb/MWh, although the actual emissions are expected to be closer to 400 lb/MWh (based on the calculations presented in Table 2)."
184	Appendix I Section V. Top Down BACT Analysis B. Top Down BACT Analysis for CO_2 Recovery and Vent System	29	DOC conditions will limit the venting only to periods when the compression and transportation system is unavailable or CO_2 delivery system is unavailable due to cold gasification block startup, CO_2 compressor unplanned outage, CO_2 pipeline unplanned outage, or CO_2 off-taker unable to accept, and such venting shall not exceed 504 hours per rolling 12-month period.	Change to "DOC conditions will limit the venting only to periods when the compression and transportation system is unavailable or CO_2 delivery system is unavailable due to cold gasification block startup, CO_2 compressor unplanned outage, CO_2 pipeline unplanned outage, or CO_2 off-taker unable to accept, and such venting shall not exceed 193,394 ton/yr CO_2, which is equivalent to 504 hours per rolling 12-month period."

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
185	Appendix I Section V. Top Down BACT Analysis D. Top Down BACT Analysis for Tail Gas Thermal Oxidizer	35	The thermal oxidizer fires an additional 80 MMBtu/hr of natural gas for the periodic oxidation of vent gas during SRU startups (which will be limited to 48 hours per year).	Please change the language to "The thermal oxidizer fires an additional 80 MMBtu/hr of natural gas for the periodic oxidation of vent gas during SRU startups (which will be limited to 48 hours per year) and plant maintenance (which will be limited to 48 hours per year)."
186	Appendix I Section V. Top Down BACT Analysis D. Top Down BACT Analysis for Tail Gas Thermal Oxidizer	36	Venting associated with startup operations of the SRU will fire an additional 80 MMBtu/hr of natural gas, but such operation will be limited to 48 hours per year by DOC condition.	Please add the following "Venting associated with plant shutdown for annual maintenance of the SRU (passivation) will fire an additional 80 MMBtu/hr of natural gas, but such operation will be limited to 24 hours per year by DOC condition."
187	Appendix I Section V. Top Down BACT Analysis D. Top Down BACT Analysis for Tail Gas Thermal Oxidizer	37	Compliance with these BACT requirements will be ensured with DOC conditions that require that the unit be fired solely on PUC-quality natural gas, by limiting the venting from SRU startups to 48 hours per calendar year, and require that the fuel flow rate to the thermal oxidizer be monitored.	Please change the language to "Compliance with these BACT requirements will be ensured with DOC conditions that require that the unit be fired solely on PUC-quality natural gas, by limiting the venting from SRU startups to 3,840 MMBtu per calendar year which is equivalent to 48 hours per calendar year, and from SRU maintenance to 1,920 MMBtu per calendar year which is equivalent to 24 hours per calendar year and require that the fuel flow rate to the thermal oxidizer be monitored."
188	Appendix I Section V. Top Down BACT Analysis G. Top Down BACT Analysis for Urea Absorbers	45	General	The high and low pressure urea absorbers now vent to a single stack, the Urea Absorber.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
189	Appendix I Section V. Top Down BACT Analysis J. Top Down BACT Analysis for Fugitive Emissions	52	General	Fugitive emissions have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments and are reflected in the edits to this section.
190	Appendix I-A Facility CO_2e Calculations	62-67	General	Project GHG emissions have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments.
Appendix J – Notification of Federal Land Managers				
191	No comments			
Appendix K – Ambient Air Quality Impact and Health Risk Report				
192	General comment			Project emissions and modeling have been updated to reflect the current design refinements. These changes have been outlined in the updated air quality emissions and modeling report submitted with these comments.
193	Executive Summary	Page 1	The proposed emission limits will not cause or contribute to any exceedance of the National Ambient Air Quality Standards (NAAQS) for NO_2, SO_2, CO, and PM_{10}.	Please change the statement to include $PM_{2.5}$. HECA will not cause or contribute to a $PM_{2.5}$ NAAQS exceedances because HECA will offset $PM_{2.5}$ emissions, see discussion on page 121 of PDOC.
194	Section 6.5.5	Page 17-18, Paragraph 1	The applicant performed initial "load screening" modeling… The choice of "worst case" can be different for each pollutant and averaging time, because different pollutant' emissions respond differently to temperature and flow rate.	This type of screening modeling was not performed; instead, sensitivity modeling was done as stated in the second paragraph of Section 6.5.5. The last sentence of this paragraph does not make sense. Suggest deleting and/or clarifying the first paragraph of Section 6.5.5.
195	Section 6.5.5	Page 18, last paragraph of Section 6.5.5	Sensitivity modeling was completed for CO 1-hour… Finally, maximum NO_2 1-hour NAAQS impacts occur when the CTG/HRSG and coal dryer are operating in on-peak power mode rather than off-peak power mode.	Some new sensitivity modeling was prepared; please refer to the updated emissions and modeling report for those analyses.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
196	Section 6.5.5	Page 18	Table 6-3 Source Stack Parameters	This table has no introduction indicating what stack parameters it is presenting. It actually only shows the sources and stack parameters used to model the 1-hour NO_2 NAAQS analysis. The table does not show source parameters for all HECA sources, nor differing source parameters for different source operating conditions/modeling scenarios. The table also should indicate the flare stack height/diameter shown are calculated *effective* stack heights/diameters for modeling, to differentiate from *actual* flare stack parameters. Next, the stack parameters presented for the emergency engines and ammonia startup heater are for all operating conditions when these sources are running. Lastly, some stack parameters may need to be updated with new project information. Please refer to updated emissions and modeling report.
197	Section 6.5.6	Page 19		GEP Analysis was redone with new project information, and therefore these statements will need to be updated as a result. Please refer to the updated emissions and modeling report.
198	Section 6.5.6	Page 20	Figure 6-5	Figure will need to be updated with new project information and plot plan. Please refer to updated modeling files submitted with the updated emissions and modeling report.
199	Section 6.6.1	Page 20-21	Table 6-4	Project Emissions need to be updated with new project information. Please refer to the updated emissions and modeling report. Please consider changing the title of the table to: "Table **Error! No text of specified style in document.**-1 Criteria Pollutant Emitted Compared to PSD Significance Thresholds"

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
200	Section 6.6.2	Page 21	Table 6-5	Please consider changing the column titled "Project Impact Significant?" to "Project Impact Greater than SIL?" since CO 1-hour and NO_2 1-hour project impacts from more refined analyses were determined to be not significant. Project modeled impacts need to be updated with new project information. Please refer to the updated emissions and modeling report.
201	Section 6.6.2	Page 22	The NO_2 1-hour concentration greater than the SIL of 7.5 $\mu g/m^3$ and required a cumulative and a PSD increment impact analysis.	There is no increment for NO_2 1-hour, suggest deleting this part of the sentence.
202	Section 6.6.3.1	Page 22	Peak rates that occur during startup determine the HECA significant impact area for hourly pollutants.	This statement is not necessarily true for 1-hour NAAQS with statistical forms, as startup emissions may not occur frequently enough to contribute to the statistical forms of those standards. For example, for the NO_2 1-hour NAAQS SIL and regional analyses, the turbine emissions did not represent startup mode. Please consider rewording or removing this sentence.
203	Section 6.6.3.1	Page 23	The applicant proposed that NO_2 sources with a ratio less than 2.0 (based on the ratio of annual emissions to the distance to the limits of significant impact) be eligible for exclusion from the relevant inventories.	Sentence should clarify that the Q/D ratio used was based on the ratio in tons/year based on daily emission rates to the distance to the project site.
204	Section 6.6.3.3	Page 25	Table 6-7 HRSG Stack NO_2/NO_X Ratio = 0.2	The HRSG Stack NO_2/NO_X Ratio used in NO_2 modeling was 0.3.
205	Section 6.6.3.4	Page 27	Start-up emissions for the CTG/HRSG are limited to 105 hours per year…Start-up emissions for the coal dryer are limited to 104 hours per year.	Start-up hours for the CTG/HRSG and the feedstock dryer have been shortened. The CTG/HRSG has 9 hours per year of startups. The feedstock dryer has 8 hours per year of startups. Please refer to the updated emissions and modeling report.
206	Section 6.6.3.5	Page 27	Table 6-8	Cumulative impact with background has changed because of project updates. Please see updated emissions and modeling report.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
207	Section 6.7.1	Page 28	....concentrations would fall below the Class I SIL out 20 to 30 km southwest of HECA, in the direction toward San Rafael Wilderness Area...	This distance range applies for $PM_{2.5}$ Class I SIL isopleths only, as other pollutant concentrations fall below Class I SILs in a much shorter distance (see Revised Figures 6-1 through 6-5 in the updated emissions and modeling report). Please clarify text.
208	Section 6.7.2.1	Page 29	Table 6-10	All emission rates and consequently, annual emissions and Q/d values have changed with project updates. However, conclusions will not change. Please refer to updated emissions and modeling report.
209	Section 6.7.2.1	Page 30	Table 6-11	All emission rates and consequently, Q/d values have changed with project updates. However, conclusions will not change. Please refer to updated emissions and modeling report.
210	Section 7.1	Page 31	Table 7-1	Predicted concentrations and consequently, total concentrations have changed with project updates. Please refer to updated emissions and modeling report.
211	Section 7.2	Page 32-33	For Class II areas, the applicant evaluated visibility impairment for two federal Class II areas within ~50 km of the project site...EPA Region IX since has requested that a Class II visibility analysis be performed for the following areas: Sequoia...Los Padres.	A Class II visibility analysis was performed for the Elk Hills area that lies 11 to 15 km south of the facility, not for Sequoia National Forest, or Los Padres National Forest, which are ~50 km away. Suggested language to more accurately represent the analysis conducted has been provided in Appendix K.
212	Section 7.2	Page 33	Table 7-2	The modeled results in this table have changed based on new project emissions. Please refer to updated emissions and modeling report.
213	Section 8.2.6	Page 41	Load screening	Section is the same as Section 6.5.5. See comments for Section 6.5.5 above and apply to this section as well.
214	Section 8.2.6	Page 42	Table 8-2	Table is the same as Table 6-3. See comments for Table 6-3 above and apply to this table as well.
215	Section 8.2.7	Page 43	GEP	Section is the same as Section 6.5.6. See comments for Section 6.5.6 above and apply to this section as well.

Comment Number	PDOC Section Title	PDOC Page Number[1]	PDOC Statement[2]	Comments to San Joaquin Valley Air Pollution Control District[3]
216	Section 8.2.7	Page 44	Figure 8-2	Figure is the same as Figure 6-5. See comments for Figure 6-5 above and apply to this figure as well.
217	Section 8.2.8	Page 44-45	Table 8-3	The permit ID and Lbs/Day for the equipment have changed based on new project emissions. Please refer to updated emissions and modeling report.
218	Section 8.2.9.1	Page 47	Table 8-4	Table is the same as Table 6-7. See comments for Table 6-7 above and apply to this table as well.
219	Section 8.2.9.2	Page 49	Table 8-5	Please explain the modeling that was conducted to get the modeled impact of 111 $\mu g/m^3$ (27) for NO_2, 1-hour and why Project Impact Significant AAQS = Yes. NO_2 modeled impacts for CAAQS and NAAQS were determined to be insignificant. HECA will not have a significant PM_{10} AAQS impact because the area is in attainment for the federal standards and modeled impacts are less than the SILs, plus HECA is offsetting PM_{10} emissions. HECA will not have a significant $PM_{2.5}$ AAQS/SIL impact because HECA is obtaining offsets. Please update modeled impacts from the updated emissions and modeling report.
220	Section 9.3.3.1	Page 56	Table 9-1	Table is the same as Table 6-3. See comments for Table 6-3 above, apply to this table.
221	Section 9.3.6	Page 57	Table 9-2	Impacts in this table have changed due to project updates. Please refer to updated emissions and modeling report.
222	Section 9.3.6	Page 58-60	Table 9-3	Impacts in this table have changed due to project updates. Please refer to updated emissions and modeling report.

1 of 3 pages

RECEIVED Docket # LLC 08-AFC-8A
MAY 21 2013 HECA
5-20-13
Southern Region
HECA Project
Public Scoping Meeting for EIS

UPDATED COMMENTS for

PUBLIC SCOPING MEETING COMMENT FORM

Mr. Pozzuto, and the S.J.V.A.P.D.

Must be received on or before July 27, 2012
(Please print clearly)

Using the West, Texas explosion as the example; I am no longer reluctant to express exactly what my concerns are pertaining to the HECA plant (propcsed)

They will pollute everything; the AIR, the WATER, the hAND, farmers CROPS; Plus be a severe threat to human and animal life in the area.

If this plant is permitted to be built at Palm Farms and be so very, very near TUPMAN, and BUTTONWILLOW "Death On Our Doorsteps!!!"

Then (I) blame the FED. Government for their Greed and lack of Concern for us.

Name: SARAH E GOATCHER
Mailing Address: PO BOX 37
City: TUPMAN, CA.
State: CALIFORNIA
Zip: 93276-0037
Phone: 661-304-0014
Email:

Sarah Goatcher
PO Box 37
Tupman, CA 93276-0037

Comment forms may be mailed to:

Mr. Fred Pozzuto
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

Comment forms may be sent by e-mail to:

fred.pozzuto@netl.doe.gov

Copies of "3" letters I have sent to Mr. Pozzuto, Jennifer Jennings and to you! S.J.V.A.P.D.

WE ARE NOT GUIENA PIGS

the AMERICAN CITIZENS (I) consider this action by the FED. GOV. as a Terrorist threat to my life and property.

Building this plant in the name of progress, is a lie, it is in the name of Greed. Then our "BLOOD" will be on their hands.

Thank You

Sarah E Goatcher
PO Box 37
Tupman, CA. 93276

Please fold here and tape before sending.

Return Address:

Sarah Goatcher
PO Box 37
Tupman, CA 93276-0037

P.S. And just for the record:
Yes; let it be known; through-out this land.
I have pleaded for our lives!

Attn: Fred Pozzuto
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

...with Alexander, and her ... sex- ... a sho ... contention that he had grown physically violent.

Sarah Leather 5-20-13

HECA

Another CASE in POINT

Proposition 65
WARNING

San Joaquin Refining Co., Inc., Tricor Refining, LLC, and Kern Oil & Refining Co. provide the following warning:

Docket #LLC 08-AFC-8A

Chemicals known to the State of California to cause cancer and chemicals known to the State of California to cause birth defects or other reproductive harm are found in crude oil, other reproductive products and their vapors, and in petroleum products and their vapors, and in other chemicals that can be found in and around our facilities.

The foregoing warning is provided pursuant to Governor of Proposition 65. This law requires the California to publish a list of chemicals "known to the State to cause cancer or reproductive toxicity." This list is compiled in accordance with a procedure established by the Proposition, and can be obtained from the California Environmental Protection Agency. Proposition 65 requires that a clear and reasonable warning be given to persons who may be exposed to the listed chemicals.

San Joaquin Refining Co., Inc. 3542 Shell Street Bakersfield, CA 93388

Tricor Refining, LLC 1134 Manor Street Bakersfield, CA 93308

Kern Oil & Refining Co. 7724 E. Panama Lane Bakersfield, CA 93307-9210

page 2
Sarah E. Leather

Docket #LLC 08-AFC-8A
HECA

Jennifer

The Bakersfield Californian **Saturday, May 11, 2013**

Please Read

World

5-20-13

Carbon dioxide levels soar to milestone level

This Article

BY DOYLE RICE
USA Today

For the first time in recorded human history, levels of carbon dioxide in the atmosphere have surpassed 400 parts per million (ppm), according to data released Friday morning from the National Oceanic and Atmospheric Administration from the Mauna Loa Observatory in Hawaii.

The average level of carbon dioxide over the past five days is 400.03 ppm. Carbon dioxide is the greenhouse gas that is responsible for 63 percent of the warming attributable to all greenhouse gases, according to NOAA's Earth System Research Laboratory in Boulder, Colo.

Increasing amounts of carbon dioxide and other gases caused by the burning of the oil, gas and coal that power our world are enhancing the natural "greenhouse effect," causing the planet to warm to levels that climate scientists say can't be linked to natural forces.

CO2 levels were around 280 ppm prior to the Industrial Revolution, when we first began releasing large amounts into the atmosphere through the burning of fossil fuels.

"That increase is not a surprise to scientists," said NOAA senior scientist Pieter Tans of the Earth System Research Lab. "The evidence is conclusive that the strong growth of global CO2 emissions from the burning of coal, oil, and natural gas is driving the acceleration."

During the last 800,000 years, CO2 fluctuated between about 180 ppm during ice ages and 280 ppm during interglacial warm periods. Today's rate of increase is more than 100 times faster than the increase that occurred when the last ice age ended.

The last time that carbon dioxide reached 400 ppm was millions of years ago. How do scientists know this?

Scientists can analyze the gases trapped in ice to reconstruct what climate was like in prehistory, but that record only goes back 800,000 years, according to the Scripps Institute of Oceanography in San Diego. It is harder to estimate carbon dioxide levels before then, but in 2009, one research team reported in the journal Nature Geoscience that it had found evidence of CO2 levels that ranged between 365 and 415 ppm, roughly 4.5 million years ago.

"They based their finding on the analysis of carbon isotopes present in compounds made by tiny marine phytoplankton preserved in ancient ocean sediments," according to Scripps.

"Crossing the 400 ppm threshold is more than a new data point about greenhouse gas levels in our atmosphere," says World Wildlife Fund chief scientist Jon Hoekstra. "It's a sobering reminder that the planet we know today will not be the planet we know tomorrow."

Page 3
Sarah E. Stachon

MICHAEL AINSWORTH / XINHUA VIA ZUMA PRESS

A policeman stands guard at an apartment building that was destroyed when a fertilizer plant exploded, devastating West, Texas, last month.

Texas launches criminal probe into plant explosion

ANGELA K. BROWN AND RAMIT PLUSHNICK-MASTI
The Associated Press

WACO, Texas — Texas law enforcement officials on Friday launched a criminal investigation into the massive fertilizer plant explosion that killed 14 people last month, after weeks of largely treating the blast as an industrial accident.

The announcement came the same day federal agents said they found bomb-making materials belonging to a paramedic who helped evacuate residents the night of the explosion. Bryce Reed was arrested early Friday on a charge of possessing a destructive device, but law enforcement officials said they had not linked the charge to the April 17 fire and blast at West Fertilizer Co.

"It is important to emphasize that at this point, no evidence has been uncovered to indicate any connection to the events surrounding the fire and subsequent explosion ... and the arrest of Bryce Reed by the ATF," the McLennan County Sheriff's Office said in a statement.

Texas Department of Public Safety said earlier Friday that the agency had instructed the Texas Rangers and the sheriff's department to conduct a criminal probe into the explosion. The agencies will join the State Fire Marshall's Office and the Bureau of Alcohol, Tobacco, Firearms and Explosives, which have been leading the investigation and never ruled out that a crime may have been committed.

"This disaster has severely impacted the community of West, and we want to ensure that no stone goes unturned and that all the facts related to this incident are uncovered," DPS Director Steven McCraw said.

Reed was in federal custody. A criminal complaint unsealed Friday afternoon said he was arrested after McLennan County deputies were called earlier this week to a home in Abbott, a town about five miles from West, and found bomb-making materials — including a galvanized metal pipe, canisters filled with fuses, a lighter, a digital scale and a variety of chemical powders.

"After further investigation, it was determined that the resident had unwittingly taken possession of the components from Reed on April 26," says the complaint signed by ATF special agent Douglas Kunze.

An ATF explosives specialist and a chemist examined the items and agreed the "combination of parts can be readily assembled into a destructive device," the complaint says.

Reed made an initial appearance in federal court in Waco on Friday, but did not enter a plea.

Officials have largely treated the West explosion as an industrial accident, though investigators still searching for the cause of a fire that preceded the blast have said they would treat the area as a crime scene until all possibilities were considered.

The State Fire Marshal's Office released a statement Friday saying it decided to continue pursuing a criminal probe because roughly 250 leads have developed and more than 400 people have been interviewed.

Authorities have focused on ammonium nitrate, a chemical commonly used as a fertilizer, but that also can be explosive in the right conditions, as the cause of the explosion

Homero Ramirez

From: listenergia@listserver.energy.ca.gov
Sent: Wednesday, May 22, 2013 2:07 PM
To: HYDROGENENERGY@LISTSERVER.ENERGY.CA.GOV
Subject: ::: Subscription E-Mail :::HYDROGENENERGY-LIST: Intervenor HECA Neighbors' Link to KGET TV 17 - Coal on Rail Road in Wasco

The Intervenor HECA Neighbors' Link to KGET TV 17 News Coverage - Coal on Rail Road in Wasco, is now available.

For more information:
http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/index.html#other
(If link above doesn't work, please copy entire link into your web browser's URL)

_/

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****

Nancy Hassman
California Energy Commission
Web Team

_/

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See our YouTube: http://www.youtube.com/calenergycommission

To unsubscribe from this list
http://www.energy.ca.gov/listservers/unsubscribe.php?lstnm=hydrogenenergy

Homero Ramirez

From: Leonard Scandura
Sent: Thursday, May 23, 2013 9:30 AM
To: Homero Ramirez
Subject: FW: coal on the rail tracks and in the air PDOC comments
Attachments: pos_March_4-1-1-1.doc

-----Original Message-----
From: Chris Romanini [mailto:roman93311@aol.com]
Sent: Thursday, May 23, 2013 9:10 AM
To: mmascaro@scsenergyllc.com; trau@heca.com; glandman@heca.com; dale_shileikis@urscorp.com; michael.carroll@lw.com; marc.campopiano@lw.com; e-recipient@caiso.com; marni.weber@conservation.ca.gov; tenslow@adamsbroadwell.com; tom.frantz49@gmail.com; andrea.issod@sierraclub.org; matt.vespa@sierraclub.org; toconnor@edf.org; gperidas@nrdc.org; bmcfarland@kerncfb.com; robert.worl@energy.ca.gov; john.heiser@energy.ca.gov; lisa.decarlo@energy.ca.gov; publicadviser@energy.ca.gov; docket@energy.ca.gov
Cc: Dave Warner; Leonard Scandura; roman93311@aol.com
Subject: coal on the rail tracks and in the air PDOC comments

May 23, 2013 08 AFC 8A
Comments on the PDOC for HECA by the SJVAPCD

The San Joaquin Valley Air district has not adequately studied the effect of coal and coal dust coming from the trains in Kern County littering the ground, polluting the air, and contaminating crops. On May 15, 2013, as documented by Channel 17 news, there was coal between 4 and 6 inches deep between the rail tracks as far as the eye could see going south out of Wasco from the coal unloading depot. When disturbed, the wind blew it decidedly to the south east, as documented by Channel 17. It appears the coal is leaking out of the bottom of the rail cars. It is also evident that open pipes about 6 inches in diameter are on the side of the rail cars with loose coal ready to fall out. These pipes dump the coal on the outside of the rails. The volume on the ground is alarming. HECA said they will not cover their rail cars but will put a spray on the top of the cars to hold down dust. But that will not stop the drainage from the bottom of the cars as was witnessed.

I am wondering what information Dave Warner has that is not public? He was quoted in the same 17 News report saying the rail cars will be totally enclosed. Where is this information coming from? That statement was also repeated by a speaker in the audience that same evening at the hearing in Buttonwillow.
Mr. Warner did not correct the speaker, letting the audience believe that coal is enclosed in the rail cars. I request Mr. Warner clarify the enclosed rail car statements.

They speak of the enclosed unloading building capturing coal dust.
But the problem is not the building. It is the tracks where the rail cars are sitting. Whether the coal is unloaded in Wasco or at the HECA site, the rail cars will sit in the open waiting to be unloaded or waiting to return to the coal mine. During this time they leak coal onto the ground in rge quantities as we see in Wasco. Coal is also spilled from these cars as they journey through California.

Recognizing now that there is

a problem with coal getting out of the
train, what new studies is the air district doing knowing the problem will escalate with the huge increase for HECA? What will be the increase of the air pollution in Wasco? Kern County? What are the risks of loose coal contaminating crops? What is the danger to people working daily breathing the dust from all that stuff on the ground and in the air? What is the recourse if ANY coal gets dumped in a right of way or near private property? And what agency is responsible for overseeing coal leaking from rail cars? This new information should require additional mitigation knowing our air will be more polluted.

We have not had experience with what could go wrong with leakage from trucks, as is HECA's alternate delivery method. We ask that the air district or the CEC investigate what could go wrong. Could coal dribble out the bottom of the coal trucks? What agency is responsible to oversee such loose coal pollution? If coal is on the roads or in a field, is that a violation?
Is there a penalty if it happens? Who is responsible for cleaning it up? Can that agency stop all operation of HECA until the problem is corrected?

No one is taking care of the mess on the tracks now, even with repeated complaints to SJVAPCD. How are we to believe anyone will be doing anything more once HECA is built and the problem escalates?

Appreciate your response to these issues.
Chris Romanini
HECA Neighbors

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
PROOF OF SERVICE
(Revised 3/4/13)

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COMMISSION – DOCKET UNIT
Attn: Docket No. 08-AFC-08A
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OTHER ENERGY COMMISSION PARTICIPANTS (LISTED FOR CONVENIENCE ONLY):

After docketing, the Docket Unit will provide a copy to the persons listed below. Do not send copies of documents to these persons unless specifically directed to do so.

KAREN DOUGLAS
Commissioner and Presiding Member

ANDREW McALLISTER
Commissioner and Associate Member

Raoul Renaud
Hearing Adviser

Galen Lemei
Adviser to Presiding Member

Jennifer Nelson
Adviser to Presiding Member

*Hazel Miranda
Adviser to Associate Member

David Hungerford
Adviser to Associate Member

Patrick Saxton
Adviser to Associate Member

Eileen Allen
Commissioners' Technical
Adviser for Facility Siting

DECLARATION OF SERVICE

I, Chris Romanini_____, declare that on _May 23_, 2013, I served and filed copies of the attached coal on the rail tracks__, dated May 23__, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

The document has been sent to the other persons on the Service List above in the following manner:

(*Check one*)

For service to all other parties and filing with the Docket Unit at the Energy Commission:

__x__ I e-mailed the document to all e-mail addresses on the Service List above and personally delivered it or deposited it in the US mail with first class postage to those persons noted above as "hard copy required"; **OR**

____ Instead of e-mailing the document, I personally delivered it or deposited it in the US mail with first class postage to all of the persons on the Service List for whom a mailing address is given.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, and that I am over the age of 18 years.

Dated: May 23, 2013_____ Chris Romanini
HECA Neighbors

Homero Ramirez

om: Leonard Scandura
Sent: Thursday, June 06, 2013 7:41 AM
To: Homero Ramirez
Subject: FW: Kern County Health and HECA please post

From: Trudy Douglass [mailto:trudydouglass@att.net]
Sent: Friday, May 31, 2013 6:46 PM
To: Roberts, Blake@Energy; rworl@energy.ca.gov; Leonard Scandura
Subject: Kern County Health and HECA please post

To:CEC and SJAPCD regarding HECA

From: Trudy Douglass

DOC 08-AFC-8A

May 25, 2013

The California Environmental Protection Agency has released the 10 most polluted zip codes in our state. Even after many years of mitigation and legal actions by our SJVAPCD we are still at the top of state and national lists for worst air pollution. 7/10 of the zip codes mentioned are in the San Joaquin Valley. Bakersfield 93307 is the 2nd one listed and it will be the first area to be impacted by HECA's emissions. How can you think that our air will be benefited by adding coal, coke, trains, and 300? trucks to the pollution that is already in our valley?

The National Disease Cluster Alliance has identified Kern County as having clusters of brain, kidney, and muscle cancer. In addition, a group of childhood cancers has also been recognized. An increase in thyroid cancer in Kern County is being studied. When the whole San Joaquin Valley is looked at, clusters of birth defects and another childhood cancer have been identified. Emissions of coal, coke, urea, sulfur, ammonium nitrate, mercury, lead, and waste particulates will not make our environment more healthy.

Please put a stop to the HECA chemical/gasification factory. You can prevent the development of additional disease clusters by just saying "NO".

Homero Ramirez

From:	Bradley Angel <bradley@greenaction.org>
Sent:	Tuesday, May 28, 2013 4:28 PM
To:	Dave Warner; Homero Ramirez
Cc:	Tom Frantz; Chris Romanini; ana@greenaction.org; alatmig@netzero.com; Andrea Issod; Evan Gillespie; Ingrid Brostrom; ccejn; 'Dolores Weller'; Deldi Reyes; Mataka, Arsenio; Monica Fish
Subject:	Request for Translation of Key Documents and Need for Equitable and new Public Comment Period on HECA
Attachments:	Greenaction letter to APCD requesting HECA translation and equitable.pdf

Dear Mr. Warner, Mr. Ramirez and the APCD,

Attached please find a letter and comments from Greenaction for Health and Environmental Justice regarding the PDOC decision and process being conducted by the Valley Air District.

We are calling on the District to translate into Spanish the key documents for the HECA permit process in order to provide a meaningful opportunity for public participation for the many Spanish-speaking Latino residents living near the proposed project site.

Additionally we call on the District to extend the public comment period due to the fact that English speakers have been given more notice about public participation opportunities than was provided to Spanish-speakers. In addition, we are alarmed to discover that the email address given to Spanish speakers to submit comments electronically is wrong, and any comments submitted to that address will not be received...a fatal flaw in your notice that requires an entirely new comment period.

We look forward to your prompt response to these concerns, and this request, and please consider this letter as formal comments on the PDOC.

Bradley Angel
Greenaction for Health and Environmental Justice

GREENACTION
for Health & Environmental Justice

May 28, 2013

Dave Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
(via email)

REQUEST FOR TRANSLATION OF ADDITIONAL DOCUMENTS INTO SPANISH AND AN EXTENSION OF THE COMMMENT PERIOD FOR THE PROPOSED HYDROGEN ENERGY CALIFORNIA PLANT

Dear Mr. Warner,

I am writing on behalf of our Spanish-speaking and Latino constituents living near the site of the proposed Hydrogen Energy California (HECA) project that would be built in an area of Kern County that is heavily polluted and is home to a large Spanish-speaking Latino population.

As you know, there is strong interest about the HECA project among Spanish-speaking, Latino residents as evidenced by the turnout of approximately100 Spanish speakers at the May 15th hearing. These residents have a strong interest in reviewing the relevant information and participating in the permitting process.

As state and federal law and the Air District's own policies support the principle of equitable public participation for all people affected by agency decisions, we are concerned that Spanish-speaking residents are not being afforded an equal opportunity to meaningfully participate in the APCD's decisions on the HECA project including the Determination of Compliance.

Kern County, which the American Lung Association ranks first in most polluted by Short-Term Particle Pollution, second in most polluted by Year-Round Particle Pollution, and fifth in most Ozone-polluted counties[1], is the site of the proposed Hydrogen Energy California (HECA) plant. Kern County also has a Latino population of 49%.[2] HECA is planned to be sited 6.5 miles from Buttonwillow, a community with a Latino population of approximately 78%, and 7 miles from Bakersfield, a community with a Latino population of approximately 46%.[3] Despite these demographics, only recently have a few notices and introductory documents about HECA been translated into Spanish and made available on the San Joaquin Valley Air Pollution Control District's (Valley Air District's) website, making it virtually impossible for a Spanish-speaking person to meaningfully engage in the public comment period.

[1] American Lung Association, *State of the Air 2013* http://www.lung.org/associations/states/california/assets/pdfs/sota-2013/sota-2013-full-report.pdf (May 28, 2013).
[2] United States Census Bureau, *2010 Demographic Profile* http://www.census.gov/popfinder/ (last visited May 28, 2013).
[3] *Id.*

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From information gathered on the Valley Air District's website, agency electronic notices about HECA began June 21, 2010. It is our understanding that the first three set of notices were solely in English. The first two were from 2010 and include a one page newspaper notice soliciting public comment on the proposed issuance of determination of compliance (DOC) to HECA and a Public Notice Package of 329 pages of the District's preliminary determination of compliance (PDOC) that was in English only. The third notice dated February 7, 2013 includes a one page newspaper notice soliciting public comment on the proposed issuance of determination of compliance (DOC) to HECA, a 642 page evaluation by the Valley Air District of the PDOC for HECA, and a 144 page document regarding Emission reduction Credits (ERCs) proposed to be used as offsets for the HECA project that give copies of Emission Reduction Credits (ERCs) proposed to be used by HECA emission offsets; listing of the pollutants, the facility and location where the emission reduction occurred, the method of generating the emission reduction, and the original District project number; and copies of the application reviews that quantified emission reduction and resulted in the issuance of ERCs to the original owner of the ERCs, all of which were also only in English.

It was not until April 4, 2013 and April 11, 2013 when Spanish language documents about the HECA project were first put on the Air District's website. Moreover, the Spanish documents are limited to a one page Notice of Preliminary Decision soliciting comment on the proposed issuance of PDOC to HECA and a 1 ¼ page summary of PDOC for HECA. These short documents omit most of the essential background information about the proposed project, including the full scope of the project, . HECA.

In addition, your Spanish language notice has a significant, fatal and enormous mistake: the email address given to Spanish speakers to submit their comments is wrong – while English speakers are told the correct address. The two Spanish language notices state that comments should be submitted to homero.ramriez@valleyair.org which is incorrect. The correct email for Homero Romirez is homero.ramirez@valleyair.org. As a result, comments submitted to the incorrect email address placed in your Spanish language notice would never be received.

In addition, we believe the Air District should have published Spanish-language notices in Spanish language media, just as you did for the English notice being published in an English language paper.

We believe that meaningful public participation requires the Air District to translate all relevant permit documents into Spanish. However at a minimum, the PDOC documents should have at least been translated into a Spanish language Executive Summary that provides essential information to readers. A one page summary sheet does not qualify as an Executive Summary and does not allow readers to make meaningful comments on the key permit document.

In addition, we are concerned that the February 7, 2013 public notice issued by the APCD was apparently in English only. Failure to translate this notice violates the federal Civil Rights Settlement Agreement between Greenaction and the Valley Air District dated February 1, 2013. The plain language of the Settlement Agreement holds the Valley Air District responsible for translating all public notices into Spanish, with the English and Spanish text on a single page.

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When searching for Spanish material from the Spanish version of the website, the same amount of Spanish language material is available: none of the 642 page Notice of Preliminary Determination of Compliance or the 144 page document regarding Emission reduction Credits (ERCs) proposed to be used as offsets for the HECA project were translated or put into an executive summary form in Spanish.

Another major concern is the fact that Spanish-speakers who make up such a large percentage of the affected population were given less time to comment than English speakers. Although the comment period was extended two times after the one page Notice of Preliminary Decision and the two paged summary of the project in Spanish were made available, and a meeting in Spanish was scheduled and conducted, Spanish speakers had only 56 days compared to 112 days for their English speaking counterparts to review material that still was not translated into Spanish – the Notice of Preliminary Determination of Compliance and the Emission reduction Credits (ERCs) report proposed to be used as offsets for the HECA project.

In light of the above facts, Latino Spanish-speaking residents have been denied an equal opportunity and a meaningful opportunity to participate in the permit process. We are therefore calling on the Air District to (1) translate into Spanish and publish the Notice of Preliminary Determination of Compliance and the document regarding Emission reduction Credits (ERCs), at a minimum in executive summary form, and (2) extend the comment period to allow Spanish-speaking residents the same amount of time as English speakers to comment on the proposed decisions for the HECA project.

We look forward to your prompt response to this request.

In addition, please include this letter as public comment on the Determination of Compliance.

Sincerely,

Bradley Angel
Executive Director

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Association of Irritated Residents
Tom Frantz, President

May 29, 2013

Dave Warner
Director of Permit Services

Re: PDOC for HECA and other private mitigation agreements
Facility # S-7616 Project # S-1121903
CEC application # 08-AFC-08A

15 Comments to the San Joaquin Valley Air District

1. The coal spilling off the rail cars has not been addressed. In either Wasco, or at the alternative HECA site, the rail cars will sit on a siding waiting to be unloaded or waiting to be taken away. While these cars sit on the siding there is ample evidence in Wasco currently that large quantities of coal falls out the bottom and bottom sides of these rail cars. This coal is in the form of fine dust and larger pieces that will ultimately weather and break down into dust. This coal dust easily blows in the wind and is a nuisance to nearby residents and to nearby crops. HECA has never said they will use another type of rail car other than what currently is going to Wasco.

There is also the question of coal spilling off of these rail cars in lesser quantities along the entire route the trains will travel.

Pieces of coal can be found along the railroad tracks throughout Kern County from the coal trains that continue to arrive in Wasco. Every few feet along these tracks, on average, there are several pieces of coal. This coal is continually breaking down into dust through oxidation and weathering. This dust is ultimately blowing away into the surrounding areas.

The air district has told the public that no coal will come off of these trains. The air district says the unloading of coal will be in an enclosed room so there will be no coal dust. The air district has failed to tell the public that significant amounts of coal falls off these rail cars while they are being moved around on the siding and while they travel through the county. There is no doubt that this coal is dusty and blows in the wind.

There must be mitigation to stop or minimize this coal and coal dust from entering the environment. It is wrong for the air district to ignore this problem and imply it doesn't exist. There must be mitigation imposed and the public must have a chance to comment on this mitigation.

2. The background values of NO2 were taken from the Shafter monitor. The air district has correctly claimed that the Shafter monitor is more conservative (higher) in these measurements than the Arvin Bear Mtn monitor.

Although the Shafter monitor is a little bit closer to the proposed HECA site than the other monitors in Kern County, there is little in the two locations that make them similar. The Shafter monitor is in the middle of town. The only industry upwind of Shafter for dozens of miles is agriculture. Highway 43 does not nearly have the traffic counts of Highways 99, 58, and Interstate 5 in other parts of the county. There are no hills near Shafter. HECA is downwind of I-5 and also downwind of massive oil field activity along Hwy 33 such as boilers, flares, generators, and waste water ponds. HECA is also backed up against the hills. The only similarity with Shafter is nearby agriculture.

Since there is nothing particularly similar between Shafter and HECA, it makes sense for the most conservative monitor in Kern County to be used to gather background NO2 readings. For this reason, an analysis must be made to find the most conservative monitor in Kern County and compare the results from using that monitor to the results with the Shafter monitor. This must be done to see if any monitor is more conservative and if this leads to any violation of federal or state NO2 standards such as the one-hour standard. It is not enough to say Shafter is more conservative than Arvin. The public needs to know if Shafter is more conservative than Oildale, California, Edison, and Maricopa as well. The air district should definitely be using the most conservative monitor and must give evidence that it did.

3. There does not seem to be any mitigation for the VOC's and PM10 (including PM 2.5) from the trucking related emissions for this project. The voluntary or private agreement only addresses the NOx emissions. All emissions must be mitigated, not just NOx. The air district claims all emissions are mitigated so show the public that is true.

4. Some of the project emissions are only mitigated down to the threshold with the purchase of emission reduction credits. How are the emissions below the threshold being mitigated? It is not enough to say the 1.5 distance ratio covers these extra emissions. That should be done for the emissions below the threshold as well. All emissions must be mitigated. Why is the 1.5 distance ratio not applied for the NOx emissions covered by the voluntary agreements? Can the air district guarantee that all future emission reductions obtained by that extra mitigation agreement(s) be used within 15 miles of the project?

5. The air district has other money for grant and incentive programs. Will the approximately 8 million dollars from these extra HECA agreements be pooled with other district money designated for incentive funding or will it be kept separate. Most incentive money is used throughout the San Joaquin Valley for qualifying projects. Will the HECA funds also be used throughout the San Joaquin Valley or will they be designated just for Kern County and not displace other funding that would also be destined for Kern County?

6. Has the air district considered the pollution from the CO2 injection process which will be operated by Occidental Petroleum? At the Kern Board Supervisors meeting, Mr. Sadredin said this injection process was actually a net benefit to air quality in the region

because it would displace much dirtier steam injection. Is that the reason the air district did not consider this additional 50 tons of criteria air pollutants?

This assumption that the injection process is good for air quality is wrong and the air district should correct this earlier public statement by Mr. Sadredin. Occidental officials have made clear to the public that steam injection is no longer viable as a means of getting the oil out of the ground where the CO2 injection will take place. In other words, there would be no steam injection in this oil field if the HECA project did not take place. Therefore, the emissions from the CO2 injection must be considered new pollution. The air district needs to explain why it is not looking at this new pollution as part of the HECA project. Permitting the Occidental operation separately is wrong because it is part and parcel of the HECA project and is also before the CEC currently. It also allows the Occidental operation to slip under the thresholds of major sources for some pollutants and not mitigate all of the related emissions the same way as if it was lumped together with the greater project. Please confirm that the total mitigation required for the CO2 injection process will be less when that operation is considered separately than if that operation were considered together with all other HECA pollution. Also, please explain why the extra mitigation agreement did not include this extra pollution from the project.

7. The air district has claimed several times that this project is fully mitigated. Mr. Sadredin even claimed that air quality in Kern County (the area of the project) would actually improve if the project was built. Please give a numerical accounting of the total pollution from this project and what parts are mitigated by what means and what agreements. Also, please show clearly how air quality will actually improve in Kern County, and by how many tons of which pollutants, from this project. It is assumed the air district is neutral on this project so public claims of air quality improvement from the project must be backed up with firm and clear numbers which the public can understand.

8. More than once, air district officials stated publicly that environmentalists and the CEC like this project. Please give a reference to which environmentalists or groups like this project and which statements from the CEC show they like this project. To be fair, please also list the environmental groups which do not like this project.

9. Supervisor Couch, from Kern County and a member of the local air board, voted against approving the voluntary emission reduction agreements. Supervisor Couch had the advantage of having attended several public meetings where HECA had been discussed in detail by the applicant, the air district, and the public, prior to his vote. Please explain why the air district refused to have a public comment period on the voluntary emission reduction agreements so that the other air board members could have had a chance to also hear some discussion from the public about the project before casting their vote?

10. Why does the air district not consider air cooling to be BACT for controlling particulate emissions from the cooling towers? Have other power plants in the San Joaquin Valley used air cooling technology? Do these other power plants have far less particulate emissions in relation to the amount of power produced?

11. Is the NOx boiler emission rate of 2.5 ppm the best that other power plants in the San Joaquin Valley have done? Is it true that other power plants have actually been permitted at 2 ppm?

12. The trading of SOx emission reduction credits for PM10 has been done incorrectly. The ratio is wrong. EPA says 4:1 is the minimum and they recommend 40:1 yet the air district insists on using a 1:1 ratio. Is our air quality so good that the air district can justify the less conservative ratio even though it would be fully justifiable to use the higher one? Second, please explain how SOx credits can offset PM10 emissions. Third, please explain how these SOx emission credits are valid since there are currently very strict rules limiting SOx emissions that were not in place at the date the credits were formed. The air district has said very clearly that if future rules will force emission reductions then the credits from an earlier time are not valid.

13. Please show the progress that has been made in reducing ozone levels over the past 6 years in Kern County (2007-2012) using all monitors available. Is the improvement the last six years at a reasonable rate of progress that shows Kern County will reach federal standards by current deadlines? Six years should be a valid time frame to show at least some improvement. The air district claims a lot of improvement from 20 years ago which is true. But, it seems the rate of improvement has either slowed dramatically or even stopped in recent years. In this regard, how can the air district justify the continued use of emission reduction credits as even partial mitigation for large polluting projects such as HECA?

14. The air district claims the total transportation emissions are around 60 tons less than the emissions totaled by HECA and submitted to the CEC. Please explain the difference in detail and why the air district insists on using the less conservative number while the CEC uses the more conservative number. Why would the air district not use the higher number if it is truly being health protective towards the public? The higher number is clearly a legitimate number accepted by both HECA and the CEC. Yet, the air district contrives a lower number to the benefit of HECA. There should be at least $10 million more in mitigation money from HECA for these higher emissions.

15. Dave Warner said recently in Buttonwillow that HECA was possibly the dirtiest power plant in terms of output, that he has seen in many years and that it will be located in the county with possibly the dirtiest air in the nation and that this air is harming and killing people. He also said that if the voluntary emission agreement was shown not to be strong enough that the air district would strengthen it and take it back to the board for approval again. It is clearly not strong enough because the erc's are too old, reasonable progress towards the standards is not being made, and not all emissions from the project are being mitigated. Therefore, please take the agreement back and make it stronger. The amount of money needs to at least be tripled and there has to be a guarantee that every cent will be spent in Kern County on top of any other incentive funding Kern would ordinarily receive through the air district.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
PROOF OF SERVICE
(Revised 05/10/2013)

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COMMISSION DOCKET UNIT
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Attn: Docket No. 08-AFC-08A
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OTHER ENERGY COMMISSION PARTICIPANTS (LISTED FOR CONVENIENCE ONLY):

After docketing, the Docket Unit will provide a copy to the persons listed below. Do not send copies of documents to these persons unless specifically directed to do so.

KAREN DOUGLAS
Commissioner and Presiding Member

ANDREW McALLISTER
Commissioner and Associate Member

Raoul Renaud
Hearing Adviser

Galen Lemei
Adviser to Presiding Member

Jennifer Nelson
Adviser to Presiding Member

Hazel Miranda
Adviser to Associate Member

David Hungerford
Adviser to Associate Member

Patrick Saxton
Adviser to Associate Member

Eileen Allen
Commissioners' Technical Adviser for Facility Siting

DECLARATION OF SERVICE

I, _____Tom Frantz_____, declare that on ____May 29___, 2013, I served and filed copies of the attached _____PDOC comments_____ dated ____May 29____, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

The document has been sent to the other persons on the Service List above in the following manner:

(Check one)

For service to all other parties and filing with the Docket Unit at the Energy Commission:

__#__ I e-mailed the document to all e-mail addresses on the Service List above and personally delivered it or deposited it in the U.S. mail with first class postage to those persons noted above as "hard copy required"; **OR**

___ Instead of e-mailing the document, I personally delivered it or deposited it in the U.S. mail with first class postage to all of the persons on the Service List for whom a mailing address is given.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, and that I am over the age of 18 years.

Dated: _____**May 29**_____
___, 2013 _____Tom Frantz_____

Homero Ramirez

From:	Bradley Angel <bradley@greenaction.org>
Sent:	Thursday, May 30, 2013 11:36 AM
To:	Dave Warner; Homero Ramirez
Cc:	Tom Frantz; Chris Romanini; Andrea Issod; Evan Gillespie; anna@greenaction.org; alatmig@netzero.com; 'Dolores Weller'; Cesar mpos; reyes.deldi@epa.gov; Mataka, Arsenio
Subject:	Greenaction Comments on HECA PDOC
Attachments:	Greenaction comments on PDOC for HECA.pdf; Greenaction letter to APCD requesting HECA translation and equitable.pdf

Please find attached comments from Greenaction for Health and Environmental Justice on the Air District's PDOC for the proposed HECA project.

GREENACTION
for Health & Environmental Justice

May 30, 2013

Dave Warner
Director of Permit Services
San Joaquin Valley APCD
(via email)

ADDITIONAL COMMENTS IN OPPOSITION TO THE PROPOSED ISSUANCE OF DETERMINATION OF COMPLIANCE FOR HYDROGEN ENERGY CALIFORNIA

Dear Mr. Warner,

On behalf of our Kern County members and constituents including Spanish-speaking Latino residents living close to the site of the proposed Hydrogen Energy California (HECA) facility, we submit these comments to the Valley Air District in opposition to the proposed Determination of Compliance (DOC) for the HECA project:

We urge the district to not issue the Determination of Compliance for numerous reasons, including those stated in our May 28th comment letter raising issues of clearly defective and inadequate notice and inadequate translation which resulted in Spanish-speaking Latino residents being effectively excluded from meaningful participation in the Air District's public process.

The fact that your Spanish language notice instructed Spanish speakers to send their comments to a non-existent email address, while giving the correct address to English speakers, requires the Air District to initiate a completely new and correctly noticed public comment period.

Proceeding to issue a DOC despite the defective notice and inadequate translation of key documents would violate Title VI of the United States Civil Rights Act and California Government Code 1113, as the residents who are directly impacted by the defective notice and inadequate translation are a class of people protected by our state and federal civil rights laws. (See attachment).

In addition to the defective notice and translation concerns, there are numerous other reasons the PDOC should be rejected. The HECA plant would have a negative, significant and disparate impact on a protected class of people whose health is already being compromised by the current levels of pollution and who have had to bear a disproportionate amount of pollution in this area. Residents in the area of the proposed project are already exposed to terrible air quality in a non-attainment area, massive diesel truck traffic pollution, a Class I hazardous waste landfill, pesticides, fracking and other oilfield operations. The Air District's analysis failed to evaluate the cumulative impacts of the proposed project on a vulnerable population that already has significant pollution sources and health problems. The proposed approval of the HECA project which would add large amounts of new pollution from a coal and petcoke-burning experimental plant next to an environmental justice community that is heavily impacted by multiple pollution sources is unacceptable and reckless.

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We endorse and incorporate Sierra Club's extensive comments on the PDOC that document serious procedural issues and environmental and health impacts of the proposed HECA project.

We are also alarmed by and do not accept the pro-HECA bias and callous and complacent stance the Valley District has taken regarding the health and well-being of Kern County residents who would be impacted by this project. For example, in the May 15th hearing, you agreed with a concerned resident that Kern County's air quality is one of the worst in the nation, agreed that pollution is shortening lives, and that you have probably never issued an approval for a dirtier power plant project[1]- yet the District proposes to approve the DOC despite the clear pollution impacts on an already over-polluted population.

Further, as the Director of Permit Services, you demonstrated bias by an irrelevant and cavalier response to a concerned Tupman resident at the hearing by saying you'd rather live in Tupman after HECA was built than follow a diesel truck all the way up the I-5.[2] This comparison is ridiculous, and implies that residents should be happy having more pollution than they already have. Residents should not have to choose between being polluted by a diesel truck or a coal-burning plant.

The biased and defective permit process, and the PDOC, violate the core value of your agency which is "Protection of Public Health...protect(ing) the health of Valley residents through efforts to meet health-based state and federal ambient air-quality standards, based on science and prioritized where possible using health-risk reduction strategies."[3]

We call on the Air District to uphold your core value and mission, to comply with state and federal civil rights mandates, to follow applicable laws, and reject the HECA project.

We request and expect specific responses to each of the points raised in our comments.

For health and environmental justice,

Bradley Angel
Executive Director

[1] YouTube, *HECA hearing May 15, 2013 Buttonwillow, Kern County* http://www.youtube.com/watch?v=VzUsntJNMGI&feature=youtu.be (last visited May 30, 2013).
[2] http://www.youtube.com/watch?v=YAwSOLqh6aE
[3] San Joaquin Valley Air District, *About the District*, http://www.valleyair.org/general_info/aboutdist.htm#Mission (last visited May 30, 2013).

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Homero Ramirez

From:	Bradley Angel <bradley@greenaction.org>
Sent:	Thursday, May 30, 2013 1:08 PM
To:	Dave Warner; Homero Ramirez
Cc:	Tom Frantz; Chris Romanini; Andrea Issod; Evan Gillespie; anna@greenaction.org; alatmig@netzero.com; 'Dolores Weller'; Cesar mpos; reyes.deldi@epa.gov; Mataka, Arsenio
Subject:	Re: Greenaction Comments on HECA PDOC - corrected version
Attachments:	Greenaction comments on PDOC for HECA.pdf; Greenaction letter to APCD requesting HECA translation and equitable.pdf

Please find attached comments from Greenaction for Health and Environmental Justice on the Air District's PDOC for the proposed HECA project. Please note this contains the corrected version to replace the documents send earlier today which contained a typo.

GREENACTION
for Health & Environmental Justice

May 28, 2013

Dave Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
(via email)

REQUEST FOR TRANSLATION OF ADDITIONAL DOCUMENTS INTO SPANISH AND AN EXTENSION OF THE COMMMENT PERIOD FOR THE PROPOSED HYDROGEN ENERGY CALIFORNIA PLANT

Dear Mr. Warner,

I am writing on behalf of our Spanish-speaking and Latino constituents living near the site of the proposed Hydrogen Energy California (HECA) project that would be built in an area of Kern County that is heavily polluted and is home to a large Spanish-speaking Latino population.

As you know, there is strong interest about the HECA project among Spanish-speaking, Latino residents as evidenced by the turnout of approximately100 Spanish speakers at the May 15th hearing. These residents have a strong interest in reviewing the relevant information and participating in the permitting process.

As state and federal law and the Air District's own policies support the principle of equitable public participation for all people affected by agency decisions, we are concerned that Spanish-speaking residents are not being afforded an equal opportunity to meaningfully participate in the APCD's decisions on the HECA project including the Determination of Compliance.

Kern County, which the American Lung Association ranks first in most polluted by Short-Term Particle Pollution, second in most polluted by Year-Round Particle Pollution, and fifth in most Ozone-polluted counties[1], is the site of the proposed Hydrogen Energy California (HECA) plant. Kern County also has a Latino population of 49%.[2] HECA is planned to be sited 6.5 miles from Buttonwillow, a community with a Latino population of approximately 78%, and 7 miles from Bakersfield, a community with a Latino population of approximately 46%.[3] Despite these demographics, only recently have a few notices and introductory documents about HECA been translated into Spanish and made available on the San Joaquin Valley Air Pollution Control District's (Valley Air District's) website, making it virtually impossible for a Spanish-speaking person to meaningfully engage in the public comment period.

[1] American Lung Association, *State of the Air 2013* http://www.lung.org/associations/states/california/assets/pdfs/sota-2013/sota-2013-full-report.pdf (May 28, 2013).
[2] United States Census Bureau, *2010 Demographic Profile* http://www.census.gov/popfinder/ (last visited May 28, 2013).
[3] *Id.*

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From information gathered on the Valley Air District's website, agency electronic notices about HECA began June 21, 2010. It is our understanding that the first three set of notices were solely in English. The first two were from 2010 and include a one page newspaper notice soliciting public comment on the proposed issuance of determination of compliance (DOC) to HECA and a Public Notice Package of 329 pages of the District's preliminary determination of compliance (PDOC) that was in English only. The third notice dated February 7, 2013 includes a one page newspaper notice soliciting public comment on the proposed issuance of determination of compliance (DOC) to HECA, a 642 page evaluation by the Valley Air District of the PDOC for HECA, and a 144 page document regarding Emission reduction Credits (ERCs) proposed to be used as offsets for the HECA project that give copies of Emission Reduction Credits (ERCs) proposed to be used by HECA emission offsets; listing of the pollutants, the facility and location where the emission reduction occurred, the method of generating the emission reduction, and the original District project number; and copies of the application reviews that quantified emission reduction and resulted in the issuance of ERCs to the original owner of the ERCs, all of which were also only in English.

It was not until April 4, 2013 and April 11, 2013 when Spanish language documents about the HECA project were first put on the Air District's website. Moreover, the Spanish documents are limited to a one page Notice of Preliminary Decision soliciting comment on the proposed issuance of PDOC to HECA and a 1 ¼ page summary of PDOC for HECA. These short documents omit most of the essential background information about the proposed project, including the full scope of the project, . HECA.

In addition, your Spanish language notice has a significant, fatal and enormous mistake: the email address given to Spanish speakers to submit their comments is wrong – while English speakers are told the correct address. The two Spanish language notices state that comments should be submitted to homero.ramriez@valleyair.org which is incorrect. The correct email for Homero Romirez is homero.ramirez@valleyair.org. As a result, comments submitted to the incorrect email address placed in your Spanish language notice would never be received.

In addition, we believe the Air District should have published Spanish-language notices in Spanish language media, just as you did for the English notice being published in an English language paper.

We believe that meaningful public participation requires the Air District to translate all relevant permit documents into Spanish. However at a minimum, the PDOC documents should have at least been translated into a Spanish language Executive Summary that provides essential information to readers. A one page summary sheet does not qualify as an Executive Summary and does not allow readers to make meaningful comments on the key permit document.

In addition, we are concerned that the February 7, 2013 public notice issued by the APCD was apparently in English only. Failure to translate this notice violates the federal Civil Rights Settlement Agreement between Greenaction and the Valley Air District dated February 1, 2013. The plain language of the Settlement Agreement holds the Valley Air District responsible for translating all public notices into Spanish, with the English and Spanish text on a single page.

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When searching for Spanish material from the Spanish version of the website, the same amount of Spanish language material is available: none of the 642 page Notice of Preliminary Determination of Compliance or the 144 page document regarding Emission reduction Credits (ERCs) proposed to be used as offsets for the HECA project were translated or put into an executive summary form in Spanish.

Another major concern is the fact that Spanish-speakers who make up such a large percentage of the affected population were given less time to comment than English speakers. Although the comment period was extended two times after the one page Notice of Preliminary Decision and the two paged summary of the project in Spanish were made available, and a meeting in Spanish was scheduled and conducted, Spanish speakers had only 56 days compared to 112 days for their English speaking counterparts to review material that still was not translated into Spanish – the Notice of Preliminary Determination of Compliance and the Emission reduction Credits (ERCs) report proposed to be used as offsets for the HECA project.

In light of the above facts, Latino Spanish-speaking residents have been denied an equal opportunity and a meaningful opportunity to participate in the permit process. We are therefore calling on the Air District to (1) translate into Spanish and publish the Notice of Preliminary Determination of Compliance and the document regarding Emission reduction Credits (ERCs), at a minimum in executive summary form, and (2) extend the comment period to allow Spanish-speaking residents the same amount of time as English speakers to comment on the proposed decisions for the HECA project.

We look forward to your prompt response to this request.

In addition, please include this letter as public comment on the Determination of Compliance.

Sincerely,

Bradley Angel
Executive Director

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GREENACTION
for Health & Environmental Justice

May 30, 2013

Dave Warner
Director of Permit Services
San Joaquin Valley APCD
(via email)

ADDITIONAL COMMENTS IN OPPOSITION TO THE PROPOSED ISSUANCE OF DETERMINATION OF COMPLIANCE FOR HYDROGEN ENERGY CALIFORNIA

Dear Mr. Warner,

On behalf of our Kern County members and constituents including Spanish-speaking Latino residents living close to the site of the proposed Hydrogen Energy California (HECA) facility, we submit these comments to the Valley Air District in opposition to the proposed Determination of Compliance (DOC) for the HECA project:

We urge the district to not issue the Determination of Compliance for numerous reasons, including those stated in our May 28th comment letter raising issues of clearly defective and inadequate notice and inadequate translation which resulted in Spanish-speaking Latino residents being effectively excluded from meaningful participation in the Air District's public process.

The fact that your Spanish language notice instructed Spanish speakers to send their comments to a non-existent email address, while giving the correct address to English speakers, requires the Air District to initiate a completely new and correctly noticed public comment period.

Proceeding to issue a DOC despite the defective notice and inadequate translation of key documents would violate Title VI of the United States Civil Rights Act and California Government Code 11135, as the residents who are directly impacted by the defective notice and inadequate translation are a class of people protected by our state and federal civil rights laws. (See attachment).

In addition to the defective notice and translation concerns, there are numerous other reasons the PDOC should be rejected. The HECA plant would have a negative, significant and disparate impact on a protected class of people whose health is already being compromised by the current levels of pollution and who have had to bear a disproportionate amount of pollution in this area. Residents in the area of the proposed project are already exposed to terrible air quality in a non-attainment area, massive diesel truck traffic pollution, a Class I hazardous waste landfill, pesticides, fracking and other oilfield operations. The Air District's analysis failed to evaluate the cumulative impacts of the proposed project on a vulnerable population that already has significant pollution sources and health problems. The proposed approval of the HECA project which would add large amounts of new pollution from a coal and petcoke-burning experimental plant next to an environmental justice community that is heavily impacted by multiple pollution sources is unacceptable and reckless.

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We endorse and incorporate Sierra Club's extensive comments on the PDOC that document serious procedural issues and environmental and health impacts of the proposed HECA project.

We are also alarmed by and do not accept the pro-HECA bias and callous and complacent stance the Valley District has taken regarding the health and well-being of Kern County residents who would be impacted by this project. For example, in the May 15th hearing, you agreed with a concerned resident that Kern County's air quality is one of the worst in the nation, agreed that pollution is shortening lives, and that you have probably never issued an approval for a dirtier power plant project[1]- yet the District proposes to approve the DOC despite the clear pollution impacts on an already over-polluted population.

Further, as the Director of Permit Services, you demonstrated bias by an irrelevant and cavalier response to a concerned Tupman resident at the hearing by saying you'd rather live in Tupman after HECA was built than follow a diesel truck all the way up the I-5.[2] This comparison is ridiculous, and implies that residents should be happy having more pollution than they already have. Residents should not have to choose between being polluted by a diesel truck or a coal-burning plant.

The biased and defective permit process, and the PDOC, violate the core value of your agency which is "Protection of Public Health...protect(ing) the health of Valley residents through efforts to meet health-based state and federal ambient air-quality standards, based on science and prioritized where possible using health-risk reduction strategies."[3]

We call on the Air District to uphold your core value and mission, to comply with state and federal civil rights mandates, to follow applicable laws, and reject the HECA project.

We request and expect specific responses to each of the points raised in our comments.

For health and environmental justice,

Bradley Angel
Executive Director

[1] YouTube, *HECA hearing May 15, 2013 Buttonwillow, Kern County* http://www.youtube.com/watch?v=VzUsntJNMG1&feature=youtu.be (last visited May 30, 2013).
[2] http://www.youtube.com/watch?v=YAwSOLqh6aE
[3] San Joaquin Valley Air District, *About the District*, http://www.valleyair.org/general_info/aboutdist.htm#Mission (last visited May 30, 2013).

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Mr. David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

California Energy Commission
DOCKETED
08-AFC-8A
TN # 71052
MAY 30 2013

NRDC
THE EARTH'S BEST DEFENSE

30th May, 2013

Comments of the Natural Resources Defense Council on the Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903

Dear Mr. Warner,

Thank you for the opportunity to provide comments on the Preliminary Determination of Compliance (PDOC) for Hydrogen Energy California (HECA), Facility # S-7616, Project # S-1121903. The Natural Resources Defense Council (NRDC) is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has 1.4 million members and online activists nationwide, served from offices in New York, Washington D.C., San Francisco, Los Angeles, Chicago and Beijing.

Introduction

NRDC believes that carbon capture and geologic sequestration of carbon dioxide (CCS), correctly implemented, is an important component of the international and U.S. portfolio in order to reduce harmful carbon pollution from fossil fuel use in a timely manner that is consistent with climate stabilization. While we believe that renewable energy and increasing energy efficiency should be utilized first, CCS can also make significant contributions to reducing emissions. We have supported deployment of CCS technologies and have been active in advocating for the establishment of environmental safeguards and economic incentives for the technology. We also believe that the technology could help California achieve its greenhouse gas reduction goals by reducing power sector and refinery emissions, among others. However, any specific project proposal must be evaluated thoroughly and on an individual basis, not just for its potential climate benefits but for a far broader suite of issues that include air quality, water use and pollution, local impacts and environmental justice.

In these comments we address alternative fossil fuel blends for the plant's feedstock, air quality and carbon emissions in the PDOC.

Alternative fossil fuel blends

The current HECA proposal has moved away from the originally proposed use of petroleum coke (petcoke), a waste product from oil refining, as its predominant feedstock.[1] In place of petcoke, HECA currently proposes to use a mix of 75% western subbituminous coal that originates in New Mexico and 25% petcoke.[2] Petcoke from the West Coast of the U.S. is commonly shipped to Asia, where it is burned, resulting in the release of high concentrations of toxic pollutants. Gasification of the petcoke is an environmentally preferable alternative since it practically eliminates those emissions and binds the pollutants in an inert form. The Applicant's BACT analysis does not consider whether the project can use petcoke as the main or only feedstock for plant operation. It is our understanding that one of the reasons for introducing coal as a feedstock is the availability of a manufacturer performance guarantee for the gasifier, and the current unattainability of one for petcoke. However, it is plausible and even expected that using higher portions or 100% petcoke in the gasifier would prove feasible after plant operations begin in a manner that makes a commercial guarantee obtainable. We urge the San Joaquin Valley Air Pollution Control District (District) to analyze the use of alternative fossil blends that exclude coal, which would not redefine the source, and the Applicant to discuss conditions and timelines for reducing or eliminating the use of coal in the future, including the immediate term, the period after the Department of Energy demonstration phase and associated coal use requirements expire, and the longer term.

Air quality and the use of offsets

The proposed HECA facility would be situated in the San Joaquin Valley air basin, which is currently designated as nonattainment with the state and national ambient air quality standards for small particulate matter ("PM2.5"); nonattainment with the state standard for coarse particulate matter ("PM10" or "respirable particulates"); nonattainment with the 3 hour state standard for ozone, severe nonattainment with the 1-hour state standard for ozone, and extreme nonattainment with the 3 hour national standard for ozone.[3]

However, the District proposes in the PDOC to offset the HECA Project's emissions with banked emission reduction credits (ERCs) for emission reduction that occurred at other facilities decades ago. In particular, the PDOC proposes to offset NOx emissions with NOx ERCs, VOC emissions with VOC ERCs, and particulate matter emissions with SOx ERCs. Both the Clean Air Act and local rules prohibit new sources from using banked offsets if an attainment plan has not been approved for the area in question. The District does not have an approved attainment plan for either the federal 1-hour ozone standard or the 2006 federal PM2.5 standard. As such, the District cannot claim "reasonable further progress" towards attainment.

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[1] Hydrogen Energy International LLC, Application for Certification, Hydrogen Energy California, July 2008 (hereafter "08-AFC-08"), p. 1-1; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/original_afc/Volume_01/Master_Section_1.0.pdf.

[2] PDOC, p. 1, and Application, p. 2-23.

[3] PDOC, Appendix K, p. 7.

Moreover, several of the proposed ERCs appear to be invalid and not meeting the requirements of the District's rules and the Clean Air Act. As is outlined in the comments to the PDOC by the Sierra Club, "[...] about 92% of the ERCs for NOx offsets were generated by the shutdown of a catalytic cracker, fluid coker, and CO boiler on November 30, 1983 and about 8% by the installation of a selective catalytic reduction system ("SCR") and scrubber and the conversion of the source from fuel oil to natural gas in 2008. Thus, the majority of NOx offsets proposed for HECA were generated close to three decades ago.

About 63% of the ERCs for SOx used for PM10 offsets were generated by the shutdown of a tail gas incinerator on March 1, 1992, more than two decades ago, and about 37% from the installation of an SCR and scrubber and conversion from fuel oil to natural gas in 2008.

All VOC ERCs originate from the shutdown of an entire stationary source in December 1981, i.e., more than three decades ago."

The Sierra Club also asserts that certain types of offsets are not valid or were issued or sold unlawfully. We therefore urge the District to comment on the above assessment and either provide evidence to the contrary or clearly outline different options for offsetting these emissions. The Applicant should further discuss mitigation measures and expenditures in light of the above.

Carbon dioxide emission limits and enforceability

We commend the Applicant for proposing to incorporate a limit on the majority of carbon dioxide emissions from the facility in the permit, as well as the District for looking into ways in which they could enforce this. This goes beyond the vast majority of permitted facilities in the U.S. right now, but enforceability of such a limit is critically important for HECA to be able to claim credibly that it generates low-carbon output and for compliance with the emissions performance standard under SB1368.

In the Record of Teleconference Regarding SB 1368 Compliance and Applicant's Response to USEPA Comments on the SJVAPCD's PDOC[4], the District asserts that "they have reconsidered their [i.e. the District's] approach to reviewing GHG BACT requirements and concluded that the 400 lb/MWh limit in the PDOC was outside their scope of authority and would be removed from the Final DOC". Given the importance of such a limit, we urge the District to justify clearly why it believes it lacks authority and why such a course of action is preferred. We also urge the District to explain how it will deal with the issues raised in the US EPA comment letter of April 11, 2013.

If a limit in annual, monthly (or otherwise) emissions is not specified explicitly, then the District and Applicant should demonstrate that the proposed alternative formulation (expressed as a capture percentage along with assurances of underground injection and retention) is indeed tantamount to the same thing, both quantitatively, and in terms of enforceability. This should take into account auxiliary equipment, process and other relevant emissions and not just the amount of carbon dioxide captured at the gasifier. The means of monitoring performance and enforcing it should also be clearly discussed.

[4] http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2013-05-10_ROC_re_SB_1368_Compliance_and_Applicant_Response_to_USEPA_Comments_on_the_SJVAPCD_PDOC_TN-70829.pdf

We further urge the District and Applicant to present options for enforcing an increasing level of carbon dioxide performance as the plant's operations mature. While we consider it acceptable to permit carbon dioxide emissions at a higher level in the first few months that takes into account upsets during early operations and allows flexibility to gain needed experience, we do not consider it necessary for this period or highly specific conditions and circumstances to dictate the plant's permitted performance level for the rest of its lifetime. We propose a discussion of decreasing levels of plant carbon dioxide emissions according to specific milestones or timelines, or equivalent. Finally, we urge the District to discuss the level and mode of disclosure and enforceability of the plant's ongoing carbon emissions, and ensure that members of the public can obtain this information during operations as well and that the public has recourse should limits be exceeded.

Conclusion

In light of the issues raised above, we believe that the District should make revisions to the PDOC, and that the District and Applicant need to supply additional information on the issues raised. We request that sufficient time be allowed for public comment and remain at your disposal if you have further questions.

Respectfully submitted,

George Peridas, Ph.D.
Scientist, Climate Center, Co-Deputy Director, Science Center
Natural Resources Defense Council
111 Sutter St. 20th Floor, San Francisco, CA 94104
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BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
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AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
PROOF OF SERVICE
(Revised 05/10/2013)

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OTHER ENERGY COMMISSION PARTICIPANTS (LISTED FOR CONVENIENCE ONLY):

After docketing, the Docket Unit will provide a copy to the persons listed below. Do not send copies of documents to these persons unless specifically directed to do so.

KAREN DOUGLAS
Commissioner and Presiding Member

ANDREW McALLISTER
Commissioner and Associate Member

Raoul Renaud
Hearing Adviser

Galen Lemei
Adviser to Presiding Member

Jennifer Nelson
Adviser to Presiding Member

Hazel Miranda
Adviser to Associate Member

David Hungerford
Adviser to Associate Member

Patrick Saxton
Adviser to Associate Member

Eileen Allen
Commissioners' Technical Adviser for Facility Siting

DECLARATION OF SERVICE

I, Lucian Go, declare that on May 30th, 2013, I served and filed copies of the attached **Comments of the Natural Resources Defense Council on the Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903,** dated May 30th, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

The document has been sent to the other persons on the Service List above in the following manner:

(C*heck one*)

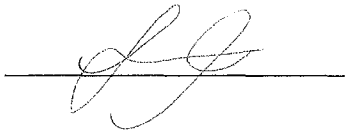
For service to all other parties and filing with the Docket Unit at the Energy Commission:

X I e-mailed the document to all e-mail addresses on the Service List above and personally delivered it or deposited it in the U.S. mail with first class postage to those persons noted above as "hard copy required"; **OR**

___ Instead of e-mailing the document, I personally delivered it or deposited it in the U.S. mail with first class postage to all of the persons on the Service List for whom a mailing address is given.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, and that I am over the age of 18 years.

Dated: May 30th, 2013



Homero Ramirez

From: Jane Parsons <JaneP@bhkcpas.com>
Sent: Thursday, May 30, 2013 2:37 PM
To: Homero Ramirez
Subject: HECA project
Attachments: 20130530143523665.pdf

I understand today is the last day to submit comments regarding the HECA project. Please add my comments already collected.
Thank you, Jane Parsons

BHK
BARBICH HOOPER KING DILL HOFFMAN

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Comments
HECA

My understanding is that the air pollution offsets being used are spread throughout the San Joaquin Valley. Has the impact of the increased emissions from the transportation and facility been considered for the southern end of the San Joaquin Valley where there may be little to no benefit from these offsets?
If some of these offsets are more than 20 years old and we are still considered to have the worst air quality in the valley, how can there be any positive benefits from these old offsets available for increased emissions in the valley?
You have discussed using the air quality monitoring stations located 13 miles from the facility. How will the air quality and increased emissions be monitored for those of us living, working and farming in less than that 13 mile radius?
You have also stated that the CO2 injection part of the entire process has not been approved, or even considered, as Occidental Petroleum has not filed for the permits for this portion of the project. How can a portion of the project be approved without considering the total impact? What will happen if this portion of the project is not approved or if the entire project, when up and running, is found to exceed acceptable standards under the guidelines you are working with?

Jan Parsons
5/30/13

Homero Ramirez

From: alatmig@netzero.net
Sent: Thursday, May 30, 2013 4:03 PM
To: Homero Ramirez
Cc: david.warner@valleyair.org
Subject: Comment Re: HECA Project

May 30, 2013

Homero Ramirez
Permit Services
San Joaquin Valley Air Pollution Control District (Via email)

Dear Mr. Ramirez:

I am writing to express my concern regarding the proposed Hydrogen Energy California (HECA) facility in Kern County. As a member of People for Clean Air & Water of Kettleman City, I would like to submit these comments in opposition to the proposed Determination of Compliance for the HECA project.

One of the reasons I am concerned about this project is the fact that many affected residents were left out of the comment period by the lack of translation of key documents. This lack of translation is a clear violation of Title VI of the Civil Rights Act which prevents discrimination by government agencies that receive federal funds.

Of additional concern is the fact that the Spanish language link that the Air District provided for on-line comment is unusable. When one clicks on the link to submit comment, it goes to an error page. This means that anyone that wanted to comment in Spanish, on-line, was unable to do so. As such, the District should definitely extend the comment period so that everyone that wants to participate in the process, is given that opportunity.

Another issue with this project is the fact that Air District staff has admitted that this plant will "increase global warming" and is the "dirtiest plant (they've) ever permitted" (Dave Warner, San Joaquin Valley Air Pollution Control District, community meeting in Buttonwillow, California, May 15, 2013). The effects of global warming may not be felt immediately, but they are certainly reason enough to rethink the permitting of this plant. Increasingly, researchers are finding that global warming causes rising sea levels, extreme weather conditions and crop failure. In an area that is already in the top 5 most polluted areas in the nation (American Lung Association, April 2013), it is irresponsible to even consider adding to the environmental burden. This is even truer given the fact that this whole process is experimental. The only thing that comes close to it is the Weyburn project in North Dakota. Unfortunately, an independent analysis of that project found that farm land around the plant has unnaturally high levels of CO2 in the soil that can be traced back to the plant. (Paul Lefleur, Petro-Find GeoChem). Since the Central Valley is a high agricultural area, can we really afford to welcome a project that may put that industry at risk?

Furthermore, Co2 capture is known to be labor intensive and expensive. This is why many projects are being abandoned. Carbon capture projects: require expensive equipment, make fuels needs go up between 25-40%, and require high capital and maintenance cost. Additionally, there is the fact that the carbon capture has to be piped somewhere else. The HECA project has already used federal funds for the permitting process. How much more are tax payers going to have to cough up for this untried and expensive project? Additionally, will permitting such a project kill the promotion of other higher energy efficiency projects like wind/solar?

With so many unanswered questions and significant issues, we urge the Air District to deny the Determination of Compliance for the good of all residents of the Central Valley.

Sincerely,

Maricela Mares-Alatorre, Member
People for Clean Air & Water of Kettleman City

BlackBerry&#174 10
Find out more about the new BlackBerry 10 smartphone.
http://thirdpartyoffers.netzero.net/TGL3241/51a7dac6ccbd5ac60d14st03duc

California Energy Commssion
DOCKETED
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TN # 71051
MAY 30 2013

By email

May 30, 2013

Robert Worl, Project Manager
California Energy Commission

Re: Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903

Dear Mr. Worl:

Please accept these comments submitted on behalf of the Sierra Club regarding the Preliminary Determination of Compliance ("PDOC"), noticed on February 7, 2013 by the San Joaquin Valley Air Pollution Control District for Hydrogen Energy California, LLC, Facility # S-7616, Project # S-1121903. These comments were prepared with the technical assistance of Petra Pless, D. Env., Bill Powers, MS, P.E., and Camille Sears, MS.

Sincerely,

Andrea Issod
Staff Attorney
Sierra Club
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andrea.issod@sierraclub.org

May 30, 2013

By email

Mr. David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308
Email: David.Warner@valleyair.org
cc: Homero.Ramirez@valleyair.org

Re: Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903

Dear Mr. Warner,

Please accept these comments submitted on behalf of Sierra Club[1] regarding the Preliminary Determination of Compliance ("PDOC"), noticed on February 7, 2013 by the San Joaquin Valley Air Pollution Control District ("District" or "SJVAPCD") for Hydrogen Energy California, LLC ("HECA" or "Applicant"), Facility # S-7616, Project # S-1121903 ("Project" or HECA Project").[2]

The Sierra Club is the oldest and largest grassroots environmental group, with over 1.3 million members and supporters. Sierra Club members live, work, attend school, travel and recreate in areas adversely affected by power plant emissions. Our members enjoy and are entitled to the benefits of natural resources that are adversely affected by interstate pollution, including air, water and soil; forests and cropland; parks, wilderness areas and other greenspace; and flora and fauna. The activities enjoyed by our membership that would be affected by the proposed HECA Project include breathing, enjoyment of scenic views, walking, gardening, hiking and work-related activities. Our membership and their families include members of sensitive

[1] These comments were prepared with the technical assistance of Petra Pless, D. Env., Bill Powers, MS, P.E., and Camille Sears, MS.

[2] SJVAPCD, Notice of Preliminary Determination of Compliance, Facility# S-7616, Project # S-1121903, February 14, 2013; http://www.valleyair.org/notices/public_notices_idx.htm.

populations such as asthmatics, the elderly and children who are at elevated risk for the deleterious health effects posed by power plant emissions.

Sierra Club understands that the California Energy Commission ("CEC") has the authority to approve the HECA Project through its Application for Certification ("AFC") process,[3] the District's PDOC is functionally equivalent to an Authority to Construct ("ATC") review, and the PDOC is intended to provide comments and guidance to the CEC on the proposed Project's compliance with air quality requirements.

Sierra Club appreciates the District's extensive efforts in drafting the PDOC for this complex project; however, Sierra Club finds that the document fails to demonstrate the Project's compliance with the requirements of the federal Clean Air Act ("CAA" or "the Act") and state Clean Air Act and implementing District regulations.

Among other issues detailed below, the PDOC impermissibly authorizes the use of invalid emission reduction credits (ERCs) to offset HECA's emissions of nonattainment pollutants. The HECA Project may not use banked ERCs to offset ozone precursors and particulate matter equal to or smaller than 2.5 micrometers ("PM2.5" or "fine particulate") because it does not have valid attainment plans in place to assure that allowing emission increases from HECA is consistent with "reasonable further progress" towards attainment. Even if the District were permitted to use banked ERCs to offset emissions from the HECA Project, several of the proposed ERCs are invalid and do not meet the requirements of the District's rules and the federal Clean Air Act.

The PDOC also fails to demonstrate compliance with national and state ambient air quality standards. Sierra Club has corrected modeling errors in the PDOC and has found that the 24-hour PM10 impacts from the proposed HECA Project will exceed the 24-hour PM10 PSD increment of 30 µg/m3 and the 50 µg/m3 24-hour PM10 CAAQS. The San Joaquin Valley already experiences very high PM10 levels, which are very close to putting the region back into nonattainment status for this pollutant. The PM10 impacts from the HECA Project only add to this concern and could jeopardize the current PM10 attainment status in the southern San Joaquin Valley. It is therefore essential that the 24-hour PM10 emission rates must be corrected and completely reassessed with updated modeling analyses in the PDOC.

Sierra Club also finds that the PDOC is inadequate in that it:

- Relies on numerous assumptions that are not adequately supported;
- Does not adequately analyze alternatives;

[3] *See* CEC, Hydrogen Energy California Power Plant Project, Docket 08-AFC-8A (Amended Application for Certification); http://energy.ca.gov/sitingcases/hydrogen_energy/index.html.

- Underestimates the Project's potential to emit ("PTE") for criteria pollutants, greenhouse gases ("GHGs"), hazardous air pollutants ("HAPs") and toxic air contaminants ("TACs");
- Fails to ensure that all emission limits would be practically enforceable;
- Fails to establish best available control technology ("BACT") for cooling towers, flares, fugitive equipment leaks, and fails to establish BACT emission limits for PM2.5 and GHGs;
- Erroneously defines the HECA Project as a synthetic minor source of HAPs;
- Fails to demonstrate compliance with the new mercury and air toxics standard ("MATS");
- Fails to address the potential for nuisance and injury or damage to business or property;
- Is impenetrable, internally inconsistent, inconsistent with information provided by the Applicant, contains a number of erroneous statements and is not adequate to inform the public of the consequences of this complex facility.

Sierra Club requests that the District substantially redraft the PDOC terms and conditions to address these issues and renotice the revised PDOC to provide adequate and correct guidance to the CEC and to provide the public with a meaningful opportunity to comment.

Sierra Club endorses Greenaction's request dated May 28, 2013, to translate all the permitting materials into Spanish and to extend the comment period to allow the Spanish speaking community living nearby the proposed plant site equal opportunity to review and comment on this major new source of air pollution.

Sierra Club will gladly provide the District with a copy of any document referenced in these comments upon request. Please do not hesitate to contact me with any questions.

Respectfully Submitted,

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I. PROJECT DESCRIPTION

The HECA Project would consist of a power generation facility, an integrated fertilizer manufacturing complex, and carbon dioxide ("CO_2") capture for off-site enhanced oil recovery ("EOR") and sequestration. The facility would use integrated gasification combined cycle ("IGCC") technology to convert a fuel blend of 75 percent western sub-bituminous coal and 25 percent petroleum coke ("petcoke") into hydrogen-rich syngas, which will be used to generate electricity in a combined-cycle power block and to manufacture nitrogen-based fertilizer.[4]

The proposed facility would be located about seven miles west of the outermost edge of the City of Bakersfield and one and a half miles northwest of the unincorporated community of Tupman in western Kern County in the San Joaquin Valley portion of the Central Valley.[5] The San Joaquin Valley air basin is currently designated as nonattainment with the state and national ambient air quality standards for fine particulate matter or PM2.5; nonattainment with the state standard for particulate matter equal to or smaller than 10 micrometers ("PM10" or "respirable particulates"); nonattainment with the 3-hour state standard for ozone, severe nonattainment with the 1-hour state standard for ozone, and extreme nonattainment with the 3-hour national standard for ozone.[6]

According to the PDOC, the HECA Project would be major source of air pollutants emitting nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), which are both ozone precursors, as well as PM10 and carbon monoxide ("CO") in excess of the District's applicable major source thresholds pursuant to SJVAPCD Rule 2201.[7] In addition, the HECA Project would be a major source for nitrogen dioxide ("NO_2"), CO, and CO_2-equivalent ("CO_2e") greenhouse gas emissions for purposes of prevention of significant deterioration ("PSD") of air quality pursuant to 40 CFR 52.21 (b)(1)(i)[8] and would emit NO_2, CO, particulate matter ("PM"), PM10 and CO_2e in excess of the applicable PSD significant emission increase thresholds.[9] The HECA Project would also emit TACs, as defined under California Title 17, CCR, §93000, and HAPs, as defined by the federal Clean Air Act §112(b)(1), including acetaldehyde,

[4] PDOC, pp. 1 and 3.

[5] *Ibid.*

[6] PDOC, Appx. K, p. 7.

[7] PDOC, p. 94.

[8] PDOC, p. 96.

[9] PDOC, p. 97.

ammonia ("NH_3"), carbonyl sulfide ("COS"), hydrogen sulfide ("H_2S"), methanol ("MeOH"), propylene, sulfuric acid and sulfates, and diesel particulate matter.[10]

The Project's surrounding area is classified as PSD Class II but there are three Class I areas – parks or wilderness areas given special protection under the federal Clean Air Act – near the Project site with one area being located within 100 kilometers ("km") of the Project site: San Rafael Wilderness (60 km); Domelands Wilderness Area (105 km), and Sequoia National Park (120 km).[11]

II. THE PDOC IS NOT ADEQUATELY SUPPORTED, INTERNALLY INCONSISTENT, AND INCONSISTENT WITH INFORMATION PROVIDED BY THE APPLICANT

As discussed below, the PDOC fails to provide adequate documentation for the District's conclusions and determinations; is inconsistent with updated emission information provided by the Applicant; and provides for the potential future expansion of the HECA Project to allow for offsite transport of liquid ammonia in contradiction to assurances made by the Applicant before the CEC.

II.A Failure to Provide Supporting Documentation

The District published the PDOC as a standalone document without including for public review the Applicant's application for Authority to Construct ("ATC") and PSD permits for the HECA Project ("Application").[12] Yet many of the PDOC's determinations, *e.g.,* its BACT determinations, reference and rely upon the Application[13] and cannot be reviewed or understood without access to information contained therein. Where the PDOC incorporates assumptions from and draws conclusions based upon the Application, it must provide either a separate standalone discussion or incorporate

[10] PDOC, Appx. H.

[11] PDOC, Appendix K, p. 29.

[12] Hydrogen Energy California LLC (HECA), Authority to Construct (ATC) Permit Application and Supplemental Information for the Prevention of Significant Deterioration (PSD) Permit Application, Hydrogen Energy California (HECA) Project, May 2012.

[13] For example, PDOC, footnotes to tables on p. 45 (*See* DOC Application, p. 2 of 32 in Appendix D"); Footnote 37, p. 97 ("These emission increases are tabulated in Table 8-4 of the PSD application, which is found in Appendix F of this evaluation."); Appx. K, p. 18 ("Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application."); Appx. K, p. 28, ("… Figure 6-1 through 6-5 of the PSD application indicates…"); Appx. K, p. 41 ("… as seen in Figure 4-1 & 4-2 of the Project application…"); Appx. K, p. 42 ("Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application."); etc.

the Applicant's document into an appendix. These materials should be provided in both English and Spanish.[14]

Further, the PDOC does not provide all detailed calculations supporting its emission estimates, thereby preventing public review of their accuracy. For example, the PDOC, p. 93, presents a summary table for the post-project stationary source potential to emit ("SSPE2") in units of pounds per year ("lbs/yr"). The PDOC provides portions of emission calculations in the main body of the text (*e.g.,* in Section VII "General Calculations" and in Appendix F for various combustion turbine generator/heat recovery steam generator ("HRSG") and coal dryer stack emission scenarios) but does not document all necessary assumptions or show comprehensively how each emission estimate was derived:

- For example, while the PDOC, Appendix F, provides detailed spreadsheets summarizing assumptions for estimating emissions from the HRSG and coal drying stack during commissioning and startup/shutdown, it does not provide similar detailed spreadsheets for operational emissions during normal operations to support the assumptions and calculations presented in the main body of the document.

- Similarly, in Appendix H the PDOC presents a summary table for annual emissions of hazardous air pollutants ("HAPs") in units of lbs/yr for HECA's emission units including the combustion turbine generator ("CTG") stack, coal dryer stack, cooling towers, auxiliary boiler, ammonia plant startup heater, emergency generator, fire water pump, flares, tail gas thermal oxidizer, CO_2 vent, manufacturing complex, etc., but does not provide the associated emission calculations for each emission unit nor does it document how individual emission rates for each unit were derived.

- Likewise, the PDOC's ambient air quality impact and health risk assessment report ("AAQI/HRA Report") describes emission scenarios and summarizes source stack parameters[15] but does not quantify the emission rates from the respective sources that were modeled. Thus, the results of the ambient air quality modeling and the PDOC's conclusion that HECA Project emissions would not result in significant health impacts are not adequately supported.

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[14] The District claims that as part of its Environmental Justice Mission it "provides outreach materials… in multiple languages," "will work to provide easy to understand summaries of plans and reports of interest in multiple languages," and "provides, as requested, real-time interpretation services for high-profile and EJ-focused forums or meetings." SJVAPCD, Environmental Justice Strategy, Amended: June 21, 2012, pp. 10-11; http://www.valleyair.org/programs/environmentaljustice/AmendedEJStrategy_June2012.pdf.

[15] PDOC, Appx. K, pp. 18, 42, and 56.

Sierra Club recommends that the District amend the PDOC to include detailed emission calculations, *i.e.*, a copy of all spreadsheets it relied upon, in appendices (comparable to Appendices D and F provided with the Application) and recirculate the document for public review.

Finally, the PDOC provides no vendor guarantees for the many assumptions it incorporates into its emission calculations, as discussed in more detail in Comment V.A.

II.B Inconsistencies in Emission Estimates

The emission estimates presented by the PDOC are internally inconsistent as well as inconsistent with more recent revised emission estimates provided by the Applicant to the CEC and Sierra Club on January 10, 2013 ("1/10/2013 HECA Updated Emissions Data"),[16] which were presumably also provided to the District. For example:

- The PDOC, p. 93, summarizes total **NOx** emissions from the facility at 371,310 lbs/year (*i.e.*, 185.7 tons/year) in contrast to p. 96 in the same document, which summarizes total NOx emission from the facility at 158.7 tons/year. Both amounts are inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total NOx emissions from the facility at 158.8 tons/year.

- The PDOC, pp. 93 and 96, summarizes total **PM10** emissions from the facility at 178,863 lbs/year and 89.4 tons/year. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total PM10 emissions from the facility at 90.1 tons/year, 0.7 tons/year higher than the PDOC.

- The PDOC, p. 93, summarizes total **PM2.5** emissions from the facility at 158,151 lbs/year (79.1 tons/year). This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total PM2.5 emissions from the facility at 79.9 tons/year, 0.8 tons/year higher than the PDOC.

- The PDOC, pp. 93 and 96, summarizes total **VOC** emissions from the facility at 75,379 lbs/year and 37.7 tons/year. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total VOC emissions from the facility at 38.4 tons/year, 0.7 tons/year higher than the PDOC.

[16] Michael Carroll, Latham & Watkins, Letter to Robert Worl, CEC, Re: Hydrogen Energy California Power Plant (08-AFC-08A), January 10, 2013, CEC Docket Log ID 69092; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-01-10_Applicant_Letter_to_CEC_re_Non_Confidential_Emissions_Data_TN-69092.pdf.

- The PDOC, Appendix H, Table 5-2, summarizes total **TAC** and **HAP** emissions from the facility at 181.47 tons/year and 15.94 tons/year, respectively. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total TAC and HAP emissions from the facility at 186.44 tons/year and 19.12 tons/year. Emissions of methanol, for example, increased from 7.09 tons/year in the PDOC to 9.83 tons/year by including methanol emissions from the CO_2 vent.

These inconsistencies amount to significant differences that could have major impacts on other analyses in the PDOC. Sierra Club recommends that the District review and confirm the Applicant's revised assumptions and most recent emission estimates for the HECA Project and incorporate updates into a revised PDOC and modeling as appropriate, taking into account Sierra Club's comments below.

II.C Inappropriate Authorization for Future Installation of Liquid Ammonia Loading Facility

The PDOC states that "the plant has been designed with facilities to load liquid ammonia for sale onto railcars or into trucks for off-site shipment to allow for future operational flexibility."[17] In the proceedings before the CEC, Sierra Club raised concerns regarding risks to the surrounding population due to an accidental release of liquid (anhydrous) ammonia caused by a traffic accident involving a delivery vehicle on non-highway delivery routes and requested preparation of a risk analysis for transportation of anhydrous ammonia resulting from a delivery vehicle accident taking into account the agricultural nature of the surrounding area and the likely presence of slow-moving and oversized agricultural vehicles on the roads.[18] In response, the Applicant stated, and confirmed several times, that it "has revised the Project to eliminate the off-site transport and sale of anhydrous ammonia. Because of this change, only urea and urea ammonium nitrate for agricultural use will be transported off-site for sale. Therefore, non-highway delivery routes and a risk analysis for the transportation of anhydrous ammonia is [sic] not applicable to the Project."[19] Therefore,

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[17] PDOC, p. 17.

[18] Sierra Club Data Request No. 85, August 2, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2012-08-03_sierra_clubs_data_requests_set_01_TN-66429.pdf.

[19] HECA Response to Sierra Club Data Request No. 85, 60-Day Extension, November 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf;

Transcript of the January 16, 2013 Status Conference, p. 39; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2013-01-16_Transcript_of_Status_Conference_TN-2918.pdf; and

the PDOC's reference to a potential future ammonia loading facility that would accommodate future operational flexibility should be removed and the flow diagram for the ammonia synthesis unit in Appendix E, Figure 2-29, should be revised to eliminate the loading facility. Sierra Club requests that the District honor the concerns regarding risks to the surrounding population and include a condition of compliance stipulating that a liquid ammonia loading facility may not be added to the HECA Project at any time in the future.

III. THE PDOC DOES NOT ADEQUATELY ADDRESS ALTERNATIVES

As discussed in the following, the PDOC fails entirely to provide an alternatives analysis to satisfy the requirements under Clean Air Act, Section 173(a)(5) and SJVAPCD Rule 2201, Section 4.15.1. Further, the alternatives analysis provided by the Applicant as part of its BACT analysis for the Application, upon which the PDOC relies to determine compliance with the requirements of the Clean Air Act at 40 CFR 52.21(j) for attainment pollutants and 40 CFR 51.165(a) for nonattainment pollutants as well as SJVAPCD Rules 2410 and 2201, is deficient.

III.A The PDOC Fails to Analyze Alternatives Under Clean Air Act Section 173(a)(5) and SJVAPCD Rule 2201, Section 4.15.1

New sources intending to locate in nonattainment areas such as the District must conduct an additional alternatives analysis that demonstrates the benefits of the proposal significantly outweigh the social and environmental impacts. Specifically, Clean Air Act Section 173(a)(5) requires "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source [that] demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification."[20] SJVAPCD Rule 2201, Section 4.15.1, implements this section as follows:

> For those sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the National Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the Public Resources Code.

The PDOC completely ignores these clear statutory and regulatory requirements. The PDOC does not even mention alternative sites, sizes and production processes. For

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HECA Response to Sierra Club Data Request No. 135, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[20] Emphasis added.

example, the PDOC does not evaluate siting the HECA Project on the Elk Hills Oil Field instead of prime agricultural land. Nor does the PDOC analyze the environmental and social costs of locating this facility around farmland and environmental justice communities already significantly overburdened by the worst air quality in the nation. The District must issue a revised PDOC before making a final decision. The PDOC must include the District's review of an alternatives analysis, as well as its determination that the benefits of the HECA Project significantly outweigh the environmental and social costs. It is critical that the District give the public an opportunity to review and comment on its analysis of the environmental and social costs of the HECA Project.

A nonattainment alternatives analysis is a broad inquiry into "the environmental and social costs" of a project.[21] Because this is a separate and distinct requirement of the Clean Air Act, it is not limited to whether or not the Project complies with other requirements of the Act such as best available control technology (in other words the alternatives section contained in the Applicant's BACT analysis does not satisfy the requirements of Clean Air Act Section 173(a)(5) besides not having been made publicly available.). One fundamental tenet of statutory construction is that every word and clause must be given effect. The District must give effect to every word in Clean Air Act Section 173(a)(5) including the broad terms "environmental and social costs" and "significantly outweigh." To adequately evaluate "environmental and social costs," the District must analyze public health and economic impacts from locating a new major source of air pollution in the dirtiest air basin in the country, impacts on sensitive populations including the nearby Elk Hills School, impacts on environmental justice communities, as well as impacts from the rail and truck emissions.

III.A.1 The Alternatives Analysis Must Consider Public Health and Economic Impacts from Increased Air Pollution in the Dirtiest Air Basin in the Country

Kern County in California's San Joaquin Valley has the worst air quality in the nation.[22] It is designated as an extreme non-attainment area for the federal 8-hour ozone standard, a nonattainment area for the state 1-hour ozone standard, a severe nonattainment area for the state 3-hour ozone standard, a nonattainment area for PM2.5 under both federal and state standards, as well as a state nonattainment area for PM10. Jared Blumenfeld, Regional Administrator for the U.S. Environmental Protection Agency ("EPA"), acknowledged the gravity of the situation when he recently stated:

[21] Clean Air Act Section 173(a)(5); SJVAPCD Rule 2201, Section 4.15.1.

[22] *See* American Lung Association, State of the Air 2013, pp. 16-18 (2013); http://www.stateoftheair.org/2013/assets/ala-sota-2013.pdf.

"Four times more people die in the San Joaquin Valley from air pollution than they do from traffic fatalities."[23]

Residents of Kern County regularly experience air pollution levels known to harm health and to increase the risk of early death. In Kern County, each person is on average exposed to unhealthy levels of ozone on over 50 days a year.[24] Ozone pollution can cause a range of impacts including school absences, hospitalizations, and even premature death. Exposure to fine particles is also very dangerous and can lead to a range of impacts including loss of work days, chronic bronchitis, and premature death.[25] Recent studies have found that asthma emergency room admissions are strongly linked to increasing fine particulate and ozone pollution across the region, and children face the highest risk.[26]

Residents also pay a high economic price for the region's poor air quality. A recent study found the cost of air pollution in the San Joaquin Valley overall is more than $1,600 per person per year in health care costs, which translates into a total of nearly $6 billion dollars a year.[27] These numbers do not include other economic impacts that residents must bear. For example, EPA has imposed a penalty on the San Joaquin Valley for not meeting progress goals towards attainment with the federal 1-hour ozone standard by the 2010 statutory deadline. That failure triggered a per-ton fee on ozone-related emissions from major industrial sources. The District, however, gutted this mandated incentive by adopting an ozone fee rule that exempts most industrial sources and instead passed on the fine to residents who must now pay a surcharge on their vehicle registration every year collecting a total of $29 million annually.[28] In addition, farmers face some of the most severe regulations and costs for compliance in the nation. The HECA Project would further increase levels of pollution in this already overburdened region and have direct and serious public health and economic impacts.

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[23] Alex Breitler, EPA Plan Keeps Valley Front, Center; Recordnet.com, January 25, 2012; http://www.recordnet.com/apps/pbcs.dll/article?AID=/20120125/A_NEWS/201250326&cid=sitesearch.

[24] Jane V. Hall, Victor Brajer, and Frederick W. Lurmann, The Benefits of Meeting Federal Clean Air Standards in the South Coast and San Joaquin Valley Air Basins, hereafter "Benefits of Meeting Federal Clean Air", November 2008; http://www.aqmd.gov/news1/2008/JaneHallStudy2008.pdf.

[25] *Ibid.*

[26] John Amson Capitman and Tim R. Tyner, The Impacts of Short-term Changes in Air Quality on Emergency Room and Hospital Use in California's San Joaquin Valley, June 2011, p. ii; http://www.fresnostate.edu/chhs/cvhpi/documents/aqr-web.pdf.

[27] Benefits of Meeting Federal Clean Air, p. 5.

[28] Steven Mayer, The Bakersfield Californian, District Sticks Drivers with Air Pollution Bill, October 21, 2010; http://www.bakersfieldcalifornian.com/local/x1485766515/District-sticks-drivers-with-air-pollution-bill; *see* also, San Joaquin Valley Pollution Control District, Air Alert 2011; http://www.valleyair.org/AirAlert/AirAlertMediaOverviewandRecap.pdf.

The alternatives analysis for the HECA Project must consider all of these public health and economic impacts.

III.A.2 The Alternatives Analysis Must Evaluate Impacts on Sensitive Populations, Including Children at Nearby Elk Hills School

One in six children in the San Joaquin Valley is diagnosed with asthma before the age of 18, an epidemic level.[29] Because of the poor air quality, children in Kern County are already restricted from playing outside many days of the year. The alternatives analysis must analyze the HECA Project's impacts on sensitive population including children as well as the elderly and residents with compromised health.

Further, the Elk Hills School is located only five miles from the HECA Project site. Children at Elk Hills School already experience dangerously elevated levels of air pollution on a regular basis. The alternatives analysis must evaluate air quality impacts and other impacts the plant might have on the Elk Hills School, such as emergency evacuation procedures.

III.A.3 The Alternatives Analysis Must Evaluate Impacts on Environmental Justice Communities

Adverse impacts of air pollution are not distributed equally in Kern County. Blacks and Hispanics experience somewhat more frequent exposures to elevated levels of fine particulate matter than non-Hispanic whites do.[30] A March 2012 study on health inequalities in the San Joaquin Valley found that life expectancy varies by as much as 21 years depending on zip code. The rate of premature deaths (years of potential life lost before the age 65) in the lowest-income zip codes of the San Joaquin Valley is nearly twice that of those in the highest-income zip codes. Additionally, areas of the San Joaquin Valley with the highest levels of respiratory risk have the highest percentage of Hispanic residents (55%), while areas with the lowest level of respiratory risk have the lowest percentage of Hispanic residents (38%).[31]

The District's alternatives analysis must fully analyze the impacts that the HECA Project would have on environmental justice communities surrounding the project site, the rail lines, as well as the areas around the roads that will experience heavy truck traffic. The project site is located close to the environmental justice communities of Tupman, Buttonwillow, and Wasco and the coal trains would run through southeast

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[29] Joint Center for Political and Economic Studies, Place Matters for Health in the San Joaquin Valley: Policy Brief, hereafter "Place Matters for Health", March 2012, p. 1; http://www.jointcenter.org/sites/default/files/upload/research/files/PM%20English.pdf.

[30] Benefits of Meeting Federal Clean Air, p. 3.

[31] Place Matters for Health, p. 1.

Bakersfield and negatively impact the environmental justice communities of Arvin and Lamont.

Coal is most commonly transported via open top rail cars, and these cars lose huge volumes of coal dust during transportation. Trucks carrying petcoke would similarly result in fugitive dust blowing from their open beds. Coal dust causes a number of well-known respiratory diseases, including pneumoconiosis (commonly known as Black Lung Disease), bronchitis and emphysema, and transportation of coal is identified by the Occupational Health and Safety Administration ("OSHA") as one of the methods for human exposure to coal dust.[32] Coal dust also contains varying amounts of heavy metals, including lead, mercury, chromium and uranium. Fugitive emissions of coal dust from transportation also cause increases in levels of coarse inhalable particulates in the air, which also present significant threats to human health. Apart from the direct health threats, fugitive coal dust along rail lines and near terminals can cause nuisance conditions for neighboring businesses and residences, resulting in economic losses due to the need for frequent cleaning.

Diesel emissions from transportation of coal, petcoke and products via both rail and truck also threaten to degrade air quality and impact human health. Fine particulate matter emissions associated with diesel engine exhaust can cause lung damage, aggravate respiratory disease such as asthma and diesel exhaust is known to cause cancer.[33] Diesel emissions have a high potential to impact people who are sensitive to the health effects of fine particles (*e.g.*, children, the elderly, and those with existing heart or lung disease, asthma or other respiratory problems).

For example, the small, rural community of Arvin in Kern County (south of Bakersfield) , which has 19,000 residents of which 93% are Latino or Hispanic[34], suffers from some of worst air quality in the nation. In addition to the persistent fine particulate matter pollution throughout the San Joaquin Valley, the community suffers from possibly more ozone violations than any other city in the country: every four days. The District expects Arvin to be the last place in the San Joaquin Valley to attain the federal 8-hour ozone standard.[35] Combustion emissions of ozone precursors from the heavy-duty diesel locomotives for rail transport of coal and truck transport of raw and waste

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[32] OSHA, Occupational Safety and Health Guideline for Coal Dust (< 5% SiO_2); http://web.archive.org/web/20120925154038/http://www.osha.gov/SLTC/healthguidelines/coaldust-less5percentsio2/recognition.html.

[33] American Cancer Society, World Health Organization Says Diesel Exhaust Causes Cancer, June 15, 2012; http://www.cancer.org/cancer/news/news/world-health-organization-says-diesel-exhaust-causes-cancer.

[34] Wikipedia, Arvin, California; http://en.wikipedia.org/wiki/Arvin,_California.

[35] EPA, Community for a Better Arvin, CA, Environmental Justice (EJ) Grant; http://www2.epa.gov/sfbay-delta/community-successes#arvin.

materials as well as fugitive coal dust from the uncovered rail cars will further aggravate the existing, already extremely unhealthy air. The alternatives analysis must evaluate the impacts of fugitive coal dust, diesel soot, and other combustion pollutants on Arvin's overburdened population, as well as other communities along the rail line from New Mexico to Wasco.

As mentioned before, residents of the San Joaquin Valley airshed pay a fine to EPA for the poor air quality in the region via their annual vehicle registration. This fine disproportionally impacts members of low income communities. The District must consider how increasing air pollution and payment of this EPA-imposed fine impacts environmental justice communities.

III.B The Applicant's BACT Analysis for Alternative Generating Technologies Is Deficient Because It Does Not Adequately Consider Clean Fuel Alternatives

The Applicant's Application, upon which the PDOC relies, provides an analysis of alternative generating technologies under Clean Air Act Sections 52.21(j) and 51.165(a), which are implemented by SJVAPCD Rules 2410 and 2201.[36] This analysis is deficient because it failed to consider cleaner fuels such as natural gas, biomass, and alternative blends. The fundamental first step in a BACT analysis is to identify all available options for reducing emissions from a proposed source. A BACT analysis must include consideration of clean fuels to lower emissions limits. BACT is defined as "an emissions limitation based on the maximum degree of reduction achievable… through… [pollution control methods] including… clean fuels…"[37] As the Environmental Appeals Board has explained:

> [C]lean fuels are an available means of reducing emissions to be considered along with other approaches in identifying BACT level controls. EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.[38]

[36] Application, Appx. B, Section 4.0.

[37] 42 U.S.C. § 7479(3); *see Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007) ("The Act is explicit that 'clean fuels' is one of the control methods that the EPA has to consider."); *Hawaiian Elec. Co., Inc. v. EPA*, 723 F.2d 1440, 1442 (9th Cir. 1984) (low sulfur fuel likely to be BACT for a facility proposing to burn high sulfur fuel).

[38] *In re Inter-Power of New York, Inc.*, 5 E.A.D. 130, 134 (EAB March 16, 1994) (internal citations omitted); http://www.epa.gov/region7/air/nsr/nsrmemos/inter-p.pdf.

The Clean Air Act "promotes clean fuels with particular vigor."[39] Failure to conduct a proper clean fuels analysis is reversible legal error, and the Environmental Appeals Board has overturned many permits on this basis.[40]

III.B.1 Use of Cleaner Fuels Would Not Redefine the Source

The only limit on the Clean Air Act's clean fuel mandate recognized by the courts is where a fuel change would fundamentally change the physical scope of the project. In other words, the "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a different type of facility- such as substituting a power plant for a municipal waste combustor.[41] The Administrator in *Hibbing Taconite* explained that a change in fuel type does not redefine the source:

> Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project… [The redefining the source] argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (*e.g.*, "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice.[42]

Any other interpretation that avoids more stringent limits based on the Applicant's desires would allow the "redefining the source" exception to swallow the rule that clean fuels must be considered as part of BACT.

> [s]ome adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal… but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a control technology.[43]

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[39] *In re N. Mich. Univ.*, PSD Appeal No. 08-02, slip op. at 18-19 (EAB February 18, 2009), p. 27; http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Recent~Additions/06DBEC31EBFD8C3E852575620052318B/$File/Denying%20and%20Remanding...79.pdf.

[40] *In re Miss. Lime Co.*, PSD Appeal No. 11-01, at 17 (EAB August 9, 2011) (remanding PSD permit for failure to properly consider natural gas as BACT for startup fuel), http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Decision~Date/8B66074F309B507C852578E70072E50F/$File/Remand%20Order...24.pdf; *In re N. Mich. Univ.*, PSD Appeal No. 08-02, slip op. at 18-19 (EAB February 18, 2009) (remanding permit for failure to properly consider burning more wood or lower sulfur coal as clean fuel); *Hibbing Taconite Co.*, 2 E.A.D. 838, 1989 WL 266359, *8 (EAB July 19, 1989) (remanding permit because agency failed to justify rejection of burning natural gas as a viable pollution control strategy); also found here: http://www.epa.gov/region7/air/nsr/nsrmemos/taconite.pdf.

[41] *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 843 and n.12 (Adm'r 1989).

[42] *Id.* (emphasis added).

[43] *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007).

In such cases, BACT must be based on burning the cleaner fuel; otherwise permitting agencies would effectively "read [clean fuels] out of the definition of [best available control technology.]" *Id.*

The PDOC fails entirely to address alternative fuels in its BACT analyses for criteria pollutants. The PDOC's GHG BACT analysis adopts the Applicant's unjustified conclusion that petcoke and coal are "key project features" that are critical to the design of the source without any further analysis.[44] HECA cannot avoid the requirements of the Clean Air Act by narrowly defining the scope of the project or because it is receiving funding from the Department of Energy.

Further, the PDOC's description of feedstock for the Project is faulty on many different levels.

> Feedstock. Large amounts of petcoke are produced in California and exported overseas. Petcoke and coal are raw materials that are historically inexpensive per British thermal unit [Btu] and widely available in the U.S. A purpose of this project is to use these readily available traditional solid raw materials/fuels, and demonstrate their use for the generation of clean, low-carbon electricity.[45]

The fact that large quantities of petcoke are produced in California cuts against the HECA Project's current proposal to use only 25% petcoke and use 75% coal that has to be shipped over 600 miles from New Mexico.[46] Additionally, the claim that petcoke and coal are "historically inexpensive" ignores the historic low price point of natural gas, the low cost of biofuels, and the increasing cost of coal.

III.B.2 Natural Gas as Alternative Fuel

EPA recently held that BACT requires a coal gasification plant similar to the HECA Project, the Cash Creek Generation Project in Kentucky, to evaluate natural gas as a clean fuel.[47] EPA objected to the Cash Creek permit because "[t]he BACT analysis for this permit considers different technologies and fuels at different times in the plant's operation, but the analysis does not specifically include any consideration of using natural gas instead of syngas as the primary fuel."[48] EPA instructed that even if the

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[44] PDOC, Appx. I, p. 5.

[45] *Ibid*.

[46] Application, p. 2-23 and PDOC, p. 1.

[47] EPA, In the Matter of Cash Creek Generation, LLC, Order Responding to Issues Raised in January 31, 2008 and February 13, 2008 Petitions and Denying in Part and Granting in Part Requests for Objection to Permit, December 15, 2009, p. 7; http://www.epa.gov/region7/air/title5/petitiondb/petitions/cashcreek_response2008.pdf.

[48] *Ibid*.

agency ultimately chooses to reject the natural gas option, it still must provide a "reasoned explanation that demonstrates why the option of using exclusively natural gas is not 'available' for this facility."[49]

The PDOC's BACT analysis does not adequately consider the use of natural gas as an alternative fuel. Natural gas is a technically feasible and obvious option at HECA because the facility is designed to operate on natural gas both at startup and as a secondary fuel.[50] Instead of conducting a proper BACT analysis, the Applicant offers a legal opinion describing why it believes natural gas would redefine the source and provides an unsupported conclusion that natural gas would require substantial redesign of the facility.[51]

The Applicant states that many of the unit operations and processes that have been designed for HECA are specific to the use of coal/petcoke feedstocks, and to the removal of sulfur and CO_2 from the syngas, and the production of nitrogen-based products from the hydrogen-rich syngas and claims that use of natural gas as a feedstock would require substantial re-design of the facility.[52]

The Applicant, however, provides no discussion whatsoever why and how these processes would be affected to require substantial redesign of the facility. Sierra Club has previously asked the Applicant for information how exactly these processes would be affected but the Applicant refused to answer.[53] Some of the processes would not be necessary for a natural-gas fired facility including the solid fuel handling systems and baghouses, gasifier, sour shift/gas cooling, mercury removal, acid gas removal, sulfur recovery unit and tail gas treating unit, and flares for the sulfur recovery unit, gasification system, and Rectisol unit, and could simply be eliminated. Other processes including the CO_2 absorption and compression and the CO_2 pipeline could be equally implemented for a natural-gas fired facility.

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[49] *Id*., p. 8; *see also* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, at 27 (March 2011) ("any decision to exclude an option on 'redefining the source' grounds must be explained and documented in the permit record, especially where such an option has been identified as significant in public comments."); http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

[50] PDOC, Appx. I, p. 15.

[51] Application, Appx. B, p. 13.

[52] *Ibid*.

[53] Michael Carroll, Latham & Watkins LLP, Counsel to Applicant, Applicant's Response to Sierra Club's Motion to Compel Production of Information in Response To Data Requests, Docket No. 08-AFC-8A, October 8, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-16_Applicant_Response_to_Sierra_Club_Motion_to_Compel_Production_of_Information_in_Response_to_Data_Requests_TN-67748.pdf.

In addition, the Applicant states that the combustion turbine used in this project has been specifically designed by Mitsubishi Heavy Industries ("MHI") to fire hydrogen-rich fuel and while it is capable of firing natural gas, different turbines/burners would be used if natural gas were the primary fuel.[54] Replacing a combustion turbine with a model that is optimized to burn natural gas would not constitute major redesign of the Project but merely require acquisition and installation of a different turbine. The Seventh Circuit has held that some changes to the preferred design must be considered or the term "clean fuels" would be meaningless.[55]

III.B.3 Alternative Fossil Fuel Blends

HECA originally proposed to use petcoke, a byproduct of the oil refining process, as its predominant feedstock.[56] The PDOC explains that large amounts of petcoke are produced in California, yet HECA's current proposal is to use a blend of 75% western subbituminous coal shipped 600 miles from New Mexico and 25% petcoke.[57] Clearly, gasification of petcoke is feasible and would provide benefits, yet the Applicant's BACT analysis fails to consider whether the project can use 100% petcoke, or a lesser percentage of coal than 75%, and is therefore deficient. Burning 100% petcoke or alternative blends of solid fuel in the same gasifier would not redefine the source and should be analyzed.

III.B.4 Biomass or Biomass Fuel Blend Alternative

Biomass can also be gasified or co-gasified with coal. Gasification of biomass or biomass co-gasification with coal would, for example, further reduce emissions of GHGs.[58] Not only would biomass gasification reduce direct emissions from the facility but it would also reduce emissions from open burning of biomass, which is a major contributor to air pollution in the Central Valley. In order to reduce those emissions, the District has asserted in the past that it would investigate gasification of biomass.[59] The SJVAPCD issued an ATC to Parreira Almond Processing Company in Los Banos, which

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[54] Application, Appx. B, p. 13.

[55] *Sierra Club v. EPA*, 499 F.3d at 656 ("Some adjustment in the design of the plant would be necessary… Otherwise 'clean fuels' would be read out of the definition of such technology.").

[56] Hydrogen Energy International LLC, Application for Certification, Hydrogen Energy California, July 2008 (hereafter "08-AFC-08"), p. 1-1; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/original_afc/Volume_01/Master_Section_1.0.pdf.

[57] PDOC, p. 1, and Application, p. 2-23.

[58] *See*, for example, World Coal Association, Co-firing Coal & Biomass, Ecoal, Vol. 70, March 2010; http://www.worldcoal.org/resources/ecoal-archive/ecoal---archive/co-firing-coal-biomass/.

[59] SJVAPCD, Receive and File Staff Report on Phase III to Rule 4103 (Open Burning), March 19, 2009; http://www.valleyair.org/board_meetings/gb/agenda_minutes/Agenda/2009/March/Agenda_Item_11_Mar_2009.pdf.

gasifies orchard trimmings into syngas that is used in a generator to produce electricity.[60] Most recently, Metso, a global supplier of technology and services in the process industry, supplied the equipment for a 140-MW biomass gasification plant in Finland which began operation earlier this year.[61] Clearly, biomass gasification or co-gasification with coal is feasible and must be evaluated in an alternatives analysis.

Further, biomass is readily available in the San Joaquin Valley and can be sourced locally,[62] unlike coal, which would be imported from New Mexico, and petcoke which would be imported from the Los Angeles and Santa Maria areas.[63] A proper BACT analysis must evaluate whether the gasifier can gasify biomass or a fuel blend with biomass.

IV. THE DISTRICT MAY NOT USE BANKED OFFSETS FOR THE HECA PROJECT AND HECA'S EMISSION REDUCTION CREDITS ARE NOT VALID

The PDOC proposes to offset the HECA Project's emissions with banked emission reduction credits ("ERCs"), *i.e.*, banked credits for the reduction of emissions that occurred at other facilities at some time in the past. Specifically, the PDOC proposes to offset NOx emissions with NOx ERCs, VOC emissions with VOC ERCs, and particulate matter emissions with SOx ERCs. As discussed in the comments below, the District may not allow HECA to use banked offsets because the federal Clean Air Act and local rules prohibit new sources from using banked offsets if an attainment plan has not been approved for the area. The District does not have an approved attainment plan for either the federal 1-hour ozone standard or the 2006 federal PM2.5 standard. Without these attainment plans in place, the District cannot assure that allowing these new emission increases is consistent with "reasonable further progress" towards attainment. Further, even if the District were permitted to use banked ERCs to offset emissions from the HECA Project, the discussion below shows that several of the proposed ERCs are invalid and do not meet the requirements of the District's rules and the federal Clean Air Act.

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[60] *See* California Air Resources Board, Air Quality Guidance for Siting Biorefineries in California, November 2011, p. 53; http://www.arb.ca.gov/fuels/lcfs/bioguidance/biodocs/finalbiorefineryguidenov2011.pdf.

[61] Metso, Metso-supplied World's Largest Biomass Gasification Plant Inaugurated in Finland, March 11, 2013; http://www.metso.com/energy/MPowerWArticles.nsf/WebWID/WTB-130403-22572-527D1?OpenDocument.

[62] *See,* for example, Biomass Fuel Supply Study for San Joaquin Solar 1 & 2 Power Plant; http://www.energy.ca.gov/sitingcases/sjsolar/documents/applicant/afc/AFC_volume_02/Appendix%20A%20Combined.pdf.

[63] Application, p. 2-23.

IV.A Nonattainment State Implementation Plan Requirements for Offsetting Emissions with Banked Emission Reduction Credits

EPA is required to designate each air basin in the country as "attainment" or "nonattainment" areas, depending on whether the basin meets the NAAQS for a particular pollutant.[64] Each state with a nonattainment area must develop, for review and approval by EPA, a State Implementation Plan ("SIP") that lays out how the state plans to achieve the respective NAAQS for each area.[65] Nonattainment plans must "require further reasonable progress," which is defined as "annual incremental reductions in emissions… for the purpose of ensuring attainment" of the NAAQS.[66] The first step is to compile a current inventory of actual emissions in the area and include enforceable emissions limitations, and such other control measures, means, or techniques, including offsetting requirements.[67]

SIPs must also include formal "attainment demonstrations," which show that the enforceable control measures included in the plan, measured against the projected emissions inventories, will result in air pollution reductions sufficient to bring the nonattainment area into attainment within a certain timeframe.[68] The emissions inventory and attainment demonstration must include the emissions from banked emissions reduction credits as if they were still in existence.[69] A major new stationary source must show that its emission increases will be consistent with "reasonable further progress" toward an area's attainment "by obtaining emission reductions of such air pollutant," from other sources in the nonattainment area to offset its emissions.[70] Emissions reductions must be permanent, federally enforceable, quantifiable and surplus to be valid.[71] Along with validity, to ensure reasonable further progress ("RFP")

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[64] 42 U.S.C. § 7407(d).

[65] 42 U.S.C. § 7410(a)(1).

[66] 42 U.S.C. §§ 7502(c)(3), 7501.

[67] 42 U.S.C. §§ 7502(c)(3),(6); 7410(a)(2)(A), (I).

[68] 40 C.F.R. § 51.112(a).

[69] 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) ("the attainment demonstration [must] include[s] the emissions from such previously shutdown or curtailed emissions units"); *see* generally *Emissions Trading Policy Statement: General Principles for Creating, Banking and Use of Emissions Reduction Credits*, 51 Fed. Reg. 43814, 43840 (Dec. 4, 1986) ("[i]f inventories do not treat these banked emissions as 'in the air,' or if they are otherwise relied upon for SIP planning purposes, such reductions can no longer be credited for trading."); *NRDC v. EPA*, 57 F.3d at 1276 (D.C. Cir. 2009).

[70] 42 U.S.C. § 7503(c).

[71] 40 C.F.R. §§ 51.165(a)(3)(ii)(C)(1)(i); 40 C.F.R. pt. 51, App. S § IV(C)(3)(i)(1); SJAVCD Rule 2301, § 3.8.

toward attainment, major new sources must meet additional requirements which vary depending on whether EPA has approved the area's attainment plan or not.[72]

The federal Clean Air Act allows major new sources of air pollution to be built in nonattainment areas only if the source can meet stringent requirements. The Act requires:

> by the time the source is to commence operation, sufficient offsetting emissions reductions have been obtained, such that total allowable emissions from existing sources in the region, from new or modified sources which are not major emitting facilities, and from the proposed source will be sufficiently less than total emissions from existing sources … prior to the application for such permit to construct or modify so as to represent … reasonable further progress … [73]

The federal rules implementing this provision distinguish between areas with and without approved attainment SIPs because "[b]y definition any fully approved SIP has independently assured RFP and attainment."[74] "However, with respect to those areas without the attainment demonstration mandated by section 172(a)(1), and therefore no independent assurance of RFP… it remains inappropriate… to attribute preapplication shutdowns to the construction of an unrelated new source for offset purposes."[75]

Banked credits cannot be used to offset emissions from new major stationary sources in a nonattainment area if that area does not have valid EPA-approved attainment plans in place. In *Natural Resources Defense Council* ("NRDC") *v. EPA*, the D.C. Circuit court confirmed that only areas with valid attainment demonstrations can meet the statutory requirements to "ensure[s] that emission reductions are achieved "*by the time*" the new source begins operation rather than sometime down the road after milestones have been missed." [76] (The court reversed a proposed EPA rule that eliminated the attainment demonstration requirement under certain circumstances because it was inconsistent with the statute.[77])

To summarize, if the nonattainment area has an attainment demonstration in place, then banked emissions reductions credits from pre-application shutdowns or

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[72] Compare 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) with 40 C.F.R. § 51.165(a)(3)(ii)(C)(2); *see* also *NRDC v. EPA*, 571 F.3d at 1245, 1266-1267 (D.C. Cir. 2009).

[73] 42 U.S.C. § 7503(a)(1)(A).

[74] *NRDC v. EPA*, 571 F.3d at 1266-67 (citing 54 Fed. Reg. at 27,292).

[75] 54 Fed. Reg. at 27,293; *see NRDC v. EPA*, 571 F.3d at 1267.

[76] *NRDC v. EPA*, 571 F.3d at 1267 (*emphasis* added).

[77] *NRDC v. EPA*, 571 F.3d at 1265.

permanent curtailments can be used to offset emissions increases from "an unrelated new source."[78] If the area lacks an attainment demonstration, however, only contemporaneous replacement capacity can be used to offset new emissions.[79]

San Joaquin Valley Rule 2201, 4.13.1 implements this requirement as follows:

> Major Source shutdowns or permanent curtailments in production or operating hours of a Major Source may not be used as offsets for emissions from a Major Source, a Federal Major Modification, or an SB 288 Major Modification, unless the ERC, or the emissions from which the ERC are derived, has been included in an EPA-approved attainment plan.[80]

IV.B Air Quality in the San Joaquin Valley

The San Joaquin Valley portion of the Central Valley has a long history of air pollution problems and has failed to achieve attainment with the California and national ambient air quality standards for ozone and fine particulate matter. Nowhere are the San Joaquin Valley's air pollution problems more pronounced than in the southern part of the valley between Stockton and Bakersfield, home to four million people. Bakersfield, less than 20 miles from the proposed project site, sits in a bowl surrounded on three sides by the Sierra Nevada and the California coastal ranges, which allows pollutants to build up. In 2013 the American Lung Association designated the City of Bakersfield the most polluted city in the country for particulate matter and the second most polluted city in the country for ozone. This pollution results in an astonishing number of 167,656 people at risk for cardiovascular disease, 68,419 people at risk for asthma, 25,296 people at risk for chronic bronchitis and emphysema in a population of about 851,710.[81]

With the HECA project, the District would permit a major new source of air pollution in an area where residents are frequently advised to stay indoors and homeowners prohibited to light their fireplaces during periods of high pollution. The location of the Project in the Bakersfield area would further exacerbate existing air pollution problems. Building a major new source of air pollution in one of the most polluted air sheds in the country will obstruct future progress towards reaching attainment with state and national ambient air quality standards and will contribute to adversely affecting the health of residents in the foreseeable future. ERCs generated by reducing pollution decades ago will do nothing to offset emissions from the Project. As

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[78] 54 Fed. Reg. at 27,293; 40 C.F.R. 51.165(a)(3)(ii)(C)(1)(ii); *NRDC v. EPA*, 571 F.3d at 1276.

[79] 40 C.F.R. 51.165(a)(3)(ii)(C)(2); *NRDC v. EPA*, 571 F.3d at 1276.

[80] (Emphasis added).

[81] American Lung Association, State of the Air 2013, 2013; http://www.stateoftheair.org/2013/assets/ala-sota-2013.pdf.

discussed below, some of the proposed offsets do not comply with applicable laws and regulations.

IV.C Lack of EPA Approval for Ozone and PM2.5 Attainment Plans for the San Joaquin Valley Prohibits Use of Banked Offsets

The San Joaquin Valley it is currently designated as extreme nonattainment with the 1-hour NAAQS for ozone and nonattainment with the 2006 annual NAAQS for PM2.5 but does not have EPA-approved attainment plans in place for either the 1-hour ozone or the annual PM2.5 NAAQS.

The San Joaquin Valley's history of ozone nonattainment is characterized by many years of missed deadlines and delays in crafting a plan toward achieving attainment. The history is detailed in the most recent court decision *in Sierra Club v. EPA*.[82] In brief, the San Joaquin Valley's designation has degraded from "serious" nonattainment in 1991 to "severe" in 2001, to its current "extreme" status in 2004.[83] The court invalidated the District's 2010 1-hour ozone plan because it was based on outdated data from 2004.[84] The San Joaquin Valley therefore currently does not have an approved attainment plan for the 1-hour ozone NAAQS. The District notes on its website that it expects to submit its new 1-hour ozone plan to EPA by June 2013.[85] The District may not permit HECA to use NOx and VOC ERCs to offset its ozone precursor emissions until this attainment plan is approved by EPA.

The San Joaquin Valley is also in nonattainment with fine particulate matter standards. The District has an attainment plan in place to achieve the 1997 federal standards for PM2.5, but not the 2006 standards.[86] Although the District and the California Air Resources Board ("CARB") recently approved the District's attainment plan to achieve the 2006 PM2.5 NAAQS, it has not yet been approved by EPA.[87] Thus, the District may not permit HECA to use banked ERCs for offsetting its PM2.5 emissions until the attainment plan is approved by EPA. Further, the proposed offsets are invalid and ineffectual as discussed in the following comments.

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[82] 671 F.3d at 955, 960-62 (9th Cir. 2012).

[83] *Id*.

[84] 671 F.3d at 957-58.

[85] SJVAPCD, Ozone Plans; http://www.valleyair.org/Air_Quality_Plans/Ozone_Plans.htm.

[86] SJVAPCD, Particulate Matter Plans; http://www.valleyair.org/Air_Quality_Plans/PM_Plans.htm.

[87] See 42 U.S.C. § 7410(k); *see* also 42 U.S.C. § 7502(c); 42 U.S.C. § 7410(h)(2).

IV.D Transaction History of HECA's Emission Reduction Credits

All ERCs proposed to offset emissions from HECA were derived as portions of ERCs from previous owners (*i.e.*, the prior certificate covered a larger amount of pollutant emissions and was subdivided so HECA could purchase only the portion they requested). We have summarized the history of these ERC through their various subdivisions and purchases from the original ERC owner to HECA based on a summary provided by the District and information provided in response to a public records request for the original ERCs:

- NOx: **S-3273-2** HECA (120,500/120,500/120,500/120,500 lbs/quarter) = portion of certificate S-2183-2 procured from Big West (acquired by Alon Bakersfield Refining in 2010); originates with ***S-2007130/401 Alon Bakersfield Refining*** (method of reduction: shutdown of catalytic cracker, fluid coker, and CO boiler on November 30, 1983); subdivision/purchase chronology of ERC certificates: ***S-2007130/401*** → S-2007130/402 → S-2007130/403 → S-23-3 → S-124-2 → S-237-2 → S1652-2 → S2183-2 → **S-3273-2**

- NOx: **C-1058-2** HECA (10,100/10,100/10,100/10,100 lbs/quarter) = portion of certificate C-1052-2 procured from GIC Financial Services, Inc.; originates with ***C-1022-2 Guardian Industries Corp.*** (method of reduction: install SCR and scrubber and convert from fuel oil to natural gas on January 7, 2008); subdivision/purchase chronology of ERC certificates: ***C-1022-2*** → C-1052-2 → **C-1058-2**

- SOx: **S-3275-5** HECA (42,000/42,000/42,000/42,000 lbs/quarter) = portion of certificate S-2177-5 procured from Big West (acquired by Alon Bakersfield Refining in 2010); originates with ***S-2-5 Alon Bakersfield Refining*** (method of reduction: shutdown of tail gas incinerator on March 1, 1992); subdivision/purchase chronology of ERC certificates: ***S-2-5*** → S-1650-5 → S-2177-5 → **S-3275-5**

- SOx: **C-1058-5** HECA (24,500/24,500/24,500/24,500 lbs/quarter) = portion of certificate C-1052-5 procured from GIC Financial Services; originates with ***C-1022-5 Guardian Industries Corp.*** (method of reduction: install SCR and scrubber and convert from fuel oil to natural gas on January 7, 2008); subdivision/purchase chronology of ERC certificates: ***C-1022-5*** → C-1052-5 → **C-1058-5**

- VOC: **S-3305-1** HECA (14,625/14,625/14,625/14,625 lbs/quarter) = portion of certificate S-3052-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase

chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S-3052-1 → **S-3305-1**

- VOC: **S-3557-1** HECA (11,437/11,438/11,438/11,437 lbs/quarter) = portion of certificate S-3306-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S3052-1 → S-3306-1 → **S-3557-1**

- VOC: **S-3605-1** HECA (7,937/7,938/7,938/7,937 lbs/quarter) portion of certificate S-3558-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S3052-1 → S-3306-1 → S-3558-1 → **S-3605-1**[88]

The above summary shows that about 92% of the ERCs for NOx offsets were generated by the shutdown of a catalytic cracker, fluid coker, and CO boiler on November 30, 1983 and about 8% by the installation of a selective catalytic reduction system ("SCR") and scrubber and the conversion of the source from fuel oil to natural gas in 2008. Thus, the majority of NOx offsets proposed for HECA were generated close to three decades ago. About 63% of the ERCs for SOx used for PM10 offsets were generated by the shutdown of a tail gas incinerator on March 1, 1992, more than two decades ago, and about 37% from the installation of an SCR and scrubber and conversion from fuel oil to natural gas in 2008. All VOC ERCs originate from the shutdown of an entire stationary source in December 1981, *i.e.*, more than three decades ago.

[88] Information on the method of reduction that resulted in the original ERCs was provided by the Applicant in Amended AFC, Appx. E-10; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/amended_afc/Vol-III/Appendix_E.pdf. Information on dates when the original ERCs were generated was based on a public records request for ERCs S-3305-1, S-3557-1, and S-3605-1 and on information provided by the Applicant in response to April 12, 2010 CEC workshop request #26 (Attachment 26-1 email to Will Walters/CEC); http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/responses_2010-04-12_dr/04-Air_Quality_24-36.pdf.

IV.E HECA'S 30-Year Old Proposed Offsets Conflict With the Clean Air Act

Allowing offset credit for pre-application shutdowns and curtailments is contrary to the plain meaning of the Clean Air Act. Section 173(a)(1)(A) requires that "sufficient offsetting reductions" shall be obtained "such that total allowable emissions from existing sources in the region, from new or modified sources which are not major emitting facilities, and from the proposed source will be sufficiently less than total emissions from existing sources ... prior to the application for such permit to construct or modify so as to represent ... reasonable further progress."[89] Section 173(c)(1) requires that offsets come from "an equal or greater reduction, as applicable, in *actual emissions* of such air pollutant from the same or other sources in the area."[90]

Allowing HECA to use offset credit from reductions in emissions resulting from the shutdown or curtailment of operations from more than three decades ago is inconsistent with CAA § 173(c)(1)'s requirement that new sources' emissions "shall be offset" by an equal or greater reduction in "actual emissions."[91] The plain meaning of the word "actual," is "existing or occurring *at the time*."[92] The 30-year old offsets proposed for HECA are not "actual" emissions reductions that ensure "reasonable progress" toward attainment of the NAAQS or provide a positive net air quality benefit in the area affected by the proposed source.[93]

IV.F HECA's VOC ERCS Are Not Valid

HECA proposes to offset its VOC emissions with ERC certificates S-3305-1, S-3557-1, and S-3605-1. These ERCS suffer from so many legal deficiencies it is difficult to know where to start. The District needs to explain step-by-step how these ERCS could possibly be legitimate. The ERCs are not valid because they were not in conformance with the District rules or the Clean Air Act when generated more than three decades ago. At various points in time during the last 30 years, they were erroneously quantified and discounted and also traded in violation of restrictions on their use. Any one of these reasons makes these ERCS unlawful to use as offsets for emissions from the HECA Project.

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[89] 42 U.S.C. § 7503(a)(1)(A).

[90] *Id.* § 7503(c)(1) (*emphasis* added).

[91] 42 U.S.C. § 7503(c)(1).

[92] Merriam Webster, http://www.merriam-webster.com/dictionary/actual; *see Engine Mfrs. Ass'n v. S. Coast Air Quality Mgmt. Dist.*, 541 U.S. 246, 252, 124 S.Ct. 1756, 158 L.Ed.2d 529 (2004).

[93] US EPA, New Source Review Workshop Manual, ("NSR Manual"), p. G.6; http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

IV.F.1 VOC Certificate History

As summarized in Comment IV.D. above, ERC certificates S-3305-1, S-3557-1, and S-3605-1 can be traced back through various transactions to ERC certificate S-47-1 held by Frito-Lay, Inc. ("Frito-Lay"). To summarize, the original ERC certificate S-47-1 held by Frito-Lay was reissued, subdivided, and changed hands a number of times from:

S-41-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-156-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-403-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-1463-1 Oceanair Environmental (175,000/175,000/175,000/175,000 lbs/quarter) to
S-1473-1 National Offsets (87,500/87,500/87,500/87,500 lbs/quarter) back to
S-1474-1 Oceanair Environmental (87,500/87,500/87,500/87,500 lbs/quarter) to
S-1700-1 Avenal Power Center (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2083-1 Duke Energy North America (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2813-1 Avenal Power Center (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2950-1 Aer Glan Energy (75,000/75,000/75,000/75,000 lbs/quarter) to
S2993-1 Aer Glan Energy (74,250/74,250/74,250/74,250 lbs/quarter) to
S3052-1 Aer Glan Energy (61,750/61,750/61,750/61,750 lbs/quarter) to
S-3305-1, S-3357-1, 3605-1 HECA (combined 33,999/34,001/34,001/33,999lbs/quarter).[94]

IV.F.2 VOC ERCs Were Not Generated in Conformance with Applicable Federal Clean Air Act Provisions for Emission Reductions from Facility Shutdown

Review of the District's file for ERC certificate S-47-1 shows that the associated VOC emission reductions were generated by the shutdown of the Continental Carbon Corporation ("CCC") black carbon facility at 20807 Stockdale Highway, 8 miles west of Bakersfield in December 1981.[95,96,97] Frito-Lay (then doing business as The Food Company) purchased the permits to operate ("PTOs") for the CCC facility on July 1, 1982 with the intent to surrender these PTOs to the air district in exchange for being

[94] Information from file "ERC History for HECA ERC.docx" provided by Jim Swaney, SJVAPCD, with email to David Abell, Re: Public Record Request C-2013-2-44: ERC for HECA, February 15, 2013; hereafter (Exhibit A").

[95] Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983, hereafter ("Exhibit B").

[96] *See*, for example, San Joaquin Valley Unified Air Pollution Control District, ERC Application Review, Frito-Lay, Inc., December 16, 1992, pp. 2 and 4, hereafter "Exhibit C - December 16, 1992 ERC Application Review".

[97] KCAPCD, Letter to David Howecamp, EPA, Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay, July 24, 1991 ("December 1981 shutdown of the Continental Carbon Black production stationary source"), hereafter ("Exhibit D").

permitted to offset emissions from its planned new 100-acre salty snack food manufacturing facility at 222801 Highway 58, 15 miles west of Bakersfield.[98,99]

The air district in charge at the time, *i.e.*, Kern County Air Pollution Control District ("KCAPCD") (later subsumed into SJVAPCD), informed Frito-Lay that the CCC PTOs could be used for offsetting emissions for their new snack food facility[100] (to be located about six miles from the CCC facility[101]) as long as Frito-Lay maintained the CCC PTOs in active status with the District.[102] At the time, when Frito-Lay and CCC entered into their agreement for sale of the black carbon facility, KCAPD Rule 210.1 allowed for offsets but the District apparently did not have an offset banking rule in place.[103] Instead, KCAPCD recognized in writing that the VOC emission reductions from shutdown of the CCC facility were valid ERCs.[104] Later that year, KCAPCD issued draft authorities to construct ("ATCs") to Frito-Lay for its new facility.[105]

However, on November 7, 1983, after review of Frito-Lay's draft permits, EPA expressed concerns regarding KCAPCD's interpretation of its offset rule (KCAPCD Rule 210.1, Sections 5.B.5 and 5.B.9), specifically that emission reductions from prior shutdowns location were not permitted for use as offset credits for off-site use.[106] While KCAPCD staff had apparently initially identified the same concerns during preliminary discussions with Frito-Lay in the spring of 1982, it later changed its position "based on discussions with the applicant and its legal counsel."[107] On November 10, 1983, KCAPCD communicated its disagreement with EPA's concerns over interpretation of KCAPCD Rule 210.1, Sections 5.B.5 and 5.B.9.[108] After a joint meeting with the District and Frito-Lay on April 4, 1984, EPA provided a resolution to the conflict in an April 10,

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[98] *Ibid*, p. 4.

[99] H.C. Bradbury, The Food Company, Letter to Tom Paxson, KCAPCD, September 13, 1982, hereafter (Exhibit E").

[100] Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

[101] Exhibit D, KCAPCD, Letter to David Howecamp, Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay, July 24, 1991 ("Continental Carbon Black production stationary source located approximately six miles from the Frito-Lay facility").

[102] Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

[103] Rule 210.1, Amended September 12, 1979, hereafter ("Exhibit F").

[104] Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

[105] *See*, for example, Exhibit C - December 16, 1992 ERC Application Review, p. 4.

[106] Leon Hebertson, KCAPCD, Letter to David Howecamp, EPA, November 10, 1983, hereafter ("Exhibit G").

[107] *Ibid*.

[108] *Ibid*.

1984 letter to KCAPCD. In this letter, EPA reiterated its position that off-site use of shutdown credits did not conform with then applicable provisions of 40 CFR 51.8(j)(iii)(2)(c) but acknowledged that all involved parties acted in good faith and therefore it would not require revision of the permits provided that "CCC emissions and Permits to Operate can only be used by Frito-Lay for the snack foods processing plant at their present site and may not be sold or traded."[109]

The VOC ERCs associated with shutdown of the CCC carbon black facility are therefore not valid because they were not legal when they were first accepted as ERCs by the District. The documentation shows that they were not generated in conformance with the then applicable provisions of the District's Rules or the Clean Air Act. EPA agreed not to challenge them as illegal at the time only because there was originally an explicit restriction that they could never be sold or traded.

IV.F.3 Frito-Lay's ERCs Were Unlawfully Sold

In March 1992, Frito-Lay submitted an application requesting that the remaining ERCs be banked pursuant to the newly updated SJVAPCD Rule 230.1.[110] The District issued ERC certificates to Frito-Lay (shown for ERC certificate S-0047-1[111]) with the following restriction:

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-1

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

The banked ERC certificate prohibited their use by any major source or modification except for the Frito-Lay facility. Contrary to this clear prohibition, Frito-Lay (dba Recot, Inc.) then proceeded to transfer a large portion (175,000 lbs/quarter) to Oceanair Environmental (S-1463-1) in July 2000.[112] This transaction was unlawful for at least two reasons: it was contrary to the restriction included in the ERC certificate itself as well as EPA's explicit instructions to never sell

[109] David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984. (Emphasis added), hereafter ("Exhibit H").

[110] H.C. Bradbury, Frito-Lay, Inc., Letter to David Crow, KCAPCD, Re: Frito-Lay, Inc., Kern Production Facility Emission Reduction Credit Certificate(s), April 13, 1992, hereafter ("Exhibit I").

[111] *See* ERC certificates for Frito-Lay cancelled on September 24, 1993 (consumed by S-158-1), provided by SJVAPCD in response to Public Records Request, hereafter ("Exhibit J").

[112] *See* transaction summary in Comment IV.D above and ERC certificate documentation obtained from Homero Ramirez, SJVAPCD, with email to Petra Pless, Re: ERC Project S-1011223, May 21, 2013, hereafter ("Exhibit K").

or trade these offsets,[113] perpetuating the KCAPCD's initial error in interpreting its rules in compliance with applicable Clean Air Act provisions at the time. In December 2001, Oceanair transferred a portion of the ERC (87,500 lbs/quarter) to Duke Energy Avenal, LLC (S-1700-1).[114]

When Sierra Club questioned the District about these transactions, the District stated that the transfer of the ERC certificate to Oceanair was permissible because the emissions were included in the attainment plan.[115] The District, however, may not simply "legalize" ERCs by including them in an attainment plan. Further, Sierra Club obtained a copy of the corresponding ERCs and cancellations from the District.[116] The language restricting the use of the ERCs for use at Frito-Lay's snack food facility was only removed with the transaction from OceanAir to Duke Energy Avenal in December 2001. Thus, the transfer from Frito-Lay to Oceanair still carried the restriction. The District's accompanying ERC Transfer of Ownership Review does not provide an explanation why the language was removed and why the ERCs were deemed valid for use at Avenal.

IV.F.4 Emission Reduction Credits for S-41-1 Were Incorrectly Quantified and Are Therefore Not "Quantifiable" as Required by District Rules 2201 and 2301

Emission reductions must be *real*, *surplus*, *permanent*, and *quantifiable* pursuant to District Rule 2201, Section 3.2.1 and District Rule 2301, Section 4.1.1. The VOC ERCs from shutdown of the CCC facility are not *quantifiable* because the District overestimated emissions by averaging emissions over 8 years of operations between 1972 and 1979 instead of adhering to the EPA's clear instructions to use only the past two years (when at the CC facility emissions had significantly decreased compared to the prior 6 years.) The District also potentially overestimated emissions from the CCC facility by using generic emission factors from EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42") for carbon black facilities instead of facility-specific VOC emission factors determined during the source test at the facility[117] and thereby potentially overestimated ERCs available to Frito-Lay by a substantial amount.

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[113] Exhibit H, David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984.

[114] *See* transaction summary in Comment IV.D above.

[115] Phone conversation Petra Pless with Homero Ramirez, SJVAPCD, May 21, 2013.

[116] Exhibit K, Attachments to Homero Ramirez, SJVAPCD, Email to Petra Pless, Re: ERC Project S-1011223, May 21, 2013.

[117] Exhibit C, December 16, 1992 ERC Application Review. The Districts also accounted for a 29.5% reduction in emissions of VOCs to reflect recycle of main process vent gases installed in 1978 as determined in a source test.

Average Annual Production Rate

First, in relying on an 8-year average annual production of the CCC facility between 1972 through 1979, the District knowingly acted in defiance of EPA's explicit instructions to use a 2-year average:[118]

> In addition, the calculation of credits from a shutdown *cannot* be based on permitted emissions but must be based on actual emissions (*i.e.* the average rate at which the unit actually emitted during the two year period immediately preceding the shutdown). EPA expects that the District's commitment to these requirements will prevent any further misunderstandings.

Use of this 8-year average between 1972 through 1979 overestimated actual emissions from the CCC facility because the facility considerably reduced its production prior to the acquisition of their PTOs by Frito-Lay, as shown the following table.[119]

BAKERSFIELD PLANT PRODUCTION

YEAR	TREAD	CARCASS	TOTAL
1981	8,897,300 lbs.	7,263,200 lbs.	16,160,500 lbs. (8 mos. + 10 days = .6932 yr.)
1980	11,777,100 "	15,452,300 "	27,229,400 "
1979	21,116,800 "	27,492,600 "	48,609,400 "
1978	20,848,100 "	24,922,400 "	45,770,500 "
1977	30,000,300 "	25,828,200 "	55,828,500 "
1976	18,703,000 "	21,786,500 "	40,489,500 "
1975	24,327,900 "	25,190,700 "	49,518,600 "
1974	32,349,100 "	26,538,000 "	58,887,100 "
1973	32,037,800 "	30,009,200 "	62,047,000 "
1972	29,294,000 "	27,865,100 "	57,159,100 "
Averages	22,935,140	23,234,820	46,169,960 lbs. (avg. 9.6932 yrs)
Averages	24,494,900	25,009,444	49,504,344 lbs. (avg. 9 yrs-'72 thru '80)
Averages	26,084,625	26,204,087	52,288,712 lbs. (avg. 8 yrs - '72 thru '79)

By 1980, the CCC facility had reduced its carbon black production to about half of the 8-year average from 1972 through 1979 and by 1981 the facility only operated for

[118] Exhibit H, Excerpted from David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984 (*emphasis* retained); note EPA's emphasis on "*cannot.*"

[119] Excerpted from SJVAPCD, ERC Application Review, August 21, 1992, p. 12, hereafter ("Exhibit L").

8 months before it shut down. The table also shows that the District had analyzed three average production scenarios: the 10-year average from 1972 through 1981; the 9-year average from 1972 through 1980; and the 8-year average from 1972 through 1979, settling on the highest of these average production rates rather than a conservatively low production rate.

VOC Emission Factors

Second, the District should have used the facility-specific VOC emission factors determined during the source test at the facility rather than generic AP-42 emission factors for carbon black facilities. The District's use of average AP-42 emission factors for the main process vent may considerably overestimate VOC emissions from the facility. Review of EPA's AP-42 document shows that the average value of 100 lbs VOC/ton carbon black for the main process gas vent was based on source testing at only one carbon black plant.[120] The document also provides a range of emission factors of 20 to 300 lbs VOC/ton carbon black based on a survey of fifteen other plants. The District did not discuss why it deemed the average value of 100 lbs/ton carbon black representative for quantifying emissions from the CCC facility rather than the lower end of the range of 20 lbs VOC/ton carbon black. Analogous to the potential to emit calculations discussed in Comment VII, the District should have used a conservative approach, *i.e.*, in this case the lowest emission factor.

IV.F.5 VOC ERCs Were Not Reduced to Account for Emissions from Frito-Lay Facility and Expansion

While the facility was required to donate a portion of its VOC ERCs (2,221.4 lbs/day) to the District, none of the VOC emission increases associated with Frito-Lay's snack food facility (38.5 tons/year) and its later expansion were offset with the CCC ERCs (as shown in the following excerpt from the District's ERC Application Review), presumably because the VOC emission increases were below the then applicable major source threshold of 100 tons/year:[121]

[120] *See* Exhibit L, SJVAPCD, ERC Application Review, August 21, 1992, p. 9: Footnote e to AP-42, 5/83, Table 5.3-3.

[121] Exhibit C, For example, Lance Ericksen, SJVAPCD, ERC Application Review, December 16, 1992, p. 13; and Michael Barr, Pillsbury, Madison & Sutro, Letter to Leon Hebertson, KCAPCD, Re: Frito-Lay, Inc. – Air Pollution – Highway 58 Project, Kern County, California, November 12, 1987, attached Tables 1 and 2; *see* columns "HC.", hereafter ("Exhibit M").

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:

	Pounds/Day				
	PM10	SO2	NO2	VOC	CO
Actual Reductions	560.1	4773.6	687.2	4776.6	131,848.2
Used for Snack Food Facility Offsets	282.5	303.0	479.4	-	-
Donated to District	-	2673.9	-	2221.4	130,848.2
Balance Surplus Reductions	277.5	1796.7	207.8	2555.2	1,000.0

The District did not later require Frito-Lay to offset its VOC emissions when it promulgated a lower major source threshold at 20,000 lbs/year with Rule 2201, Section 3.24.1. In other words, Frito-Lay was permitted to increase its VOC emissions without ever using any of their unlawfully created offsets and, what's more, subsequently profiting from their equally unlawful sale. The District now proposes to offset further VOC emissions increases from the HECA Project with these same ERCs. To summarize: the VOC ERCs were created to account for emission reductions from a source that presumably would have shut down anyways, additional VOC emissions of 38.5 tons/year are being released by Frito-Lay's snack food facility[122] (and more from facility expansions) without using any of the VOC ERCs generated by shutdown of the CCC facility, thus resulting in a substantial net increase of ozone precursors into the airshed. Now HECA is proposing to release an additional 37.7 tons/year (75,379 lbs/day) of VOCs,[123] using only a portion of the originally created VOC ERCs.

Clearly, the use of decades-old emission reductions based on theoretical calculations which maximized their quantity can only provide a fictitious benefit to the airshed's actual air quality. It is not surprising that the District remains in extreme ozone non-attainment.

[122] Exhibit M, Michael Barr, Pillsbury, Madison & Sutro, Letter to Leon Hebertson, KCAPCD, Re: Frito-Lay, Inc. – Air Pollution – Highway 58 Project, Kern County, California, November 12, 1987, attached Tables 1 and 2; *see* columns "HC."

[123] PDOC, Table "Post-Project Stationary Source Potential to Emit [SPPE2] (lb/year)," p. 93.

IV.G Proposed PM10 Offsets Are Not Adequate

The PDOC's proposal to offset PM10 emissions with SOx ERCs fails to take into account that the location of PM10 offsets does not coincide with PM10 ambient concentrations resulting from Project emissions and that SOx emissions convert to PM10 at different rates during summer and winter.

IV.H Proposed PM2.5 Offsets Are Not Adequate to Mitigate the Project's PM2.5 Emissions

District Rule 2201, Section 4.14.1 requires:

> Emissions from a new or modified Stationary Source shall not cause or make worse the violation of an Ambient Air Quality Standard. In making this determination, the APCO [Air Pollution Control Officer] shall take into account the increases in minor and secondary source emissions as well as the mitigation of emissions through offsets obtained pursuant to this rule.[124]

The District modeled ambient concentrations resulting from direct PM2.5 emissions pursuant to SJVAPCD Rule 2201, Section 14.4.1,[125] and found that Project emissions would contribute significantly to existing exceedances of the 24-hour and annual NAAQS and the 24-hour CAAQS for PM2.5.[126] Modeled ambient concentrations of 24-hour PM2.5 of 3.1 $\mu g/m^3$ exceed the applicable significant impact levels ("SILs") of 1.2 by a factor of more than 2.5; modeled ambient concentrations of annual PM2.5 of 0.6 $\mu g/m^3$ exceed the applicable SIL by a factor of two.[127]

Due to these modeled exceedances, the District requires offsets for the full amount of the Project's PM2.5 emissions and proposes to mitigate the HECA Project's PM2.5 emissions with SOx interpollutant offsets using ERC certificates #S-3275-5 (SOx) and #C-1058-5 (SOx).[128,129] (As discussed before, about 63% of these ERCs were generated by the shutdown of a tail gas incinerator in 1992, more than two decades ago, and about 37% from the installation of an SCR and scrubber and conversion from fuel oil to natural gas in 2008.) The District finds that the use of these offsets would fully

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[124] (Emphasis added).

[125] PDOC, pp. 120-121 and 142.

[126] PDOC, Appx. K, p. 49.

[127] PDOC, Appx. K, p. 49.

[128] PDOC, p. 122.

[129] PDOC, p. 117.

mitigate the Project's impacts on air quality.[130] This conclusion is unsubstantiated for a number of reasons.

IV.H.1 Emission Reduction Credit Certificate #C-1058-5 (SOx) Is Not Valid Because It Is Not Accounted for in an EPA-Approved PM2.5 Attainment Plan

As discussed before, all ERCs that are proposed for use for offsetting emissions from a new stationary source must be accounted for in a District's attainment plan as if they were still in existence.[131] EPA notes that it "cannot allow states to consider less than their full amount of banked deposits as 'in the air.' To do so could jeopardize air quality planning and attainment."[132] "If inventories do not treat these banked emissions as 'in the air,' or if they are otherwise relied upon for SIP planning purposes, such reductions can no longer be credited for trading."[133]

Attainment plans for PM2.5 adopted by the District include the 2008 PM2.5 Plan, which addresses progress towards attainment of the annual national ambient air quality standard for the 1997 PM2.5 standard of 15 $\mu g/m^3$ and the 2012 PM2.5 Plan, which addresses progress towards attainment of the 2006 24-hour national ambient air quality standard for PM2.5 of 35 $\mu g/m^3$. The District's 2008 PM2.5 Plan is EPA-approved and the 2012 PM2.5 Plan has recently been submitted for EPA approval but has not been approved yet.[134]

Review of the District's EPA-approved 2008 PM2.5 Plan shows that emissions associated with ERC certificate #C-1058-5 (SOx) were not accounted for in the District's inventory.[135] Thus, ERC certificate #C-1058-5 (SOx) is not valid for offsetting PM2.5 emissions from the HECA Project for purposes of demonstrating compliance with the annual NAAQS. The District does account for this ERC certificate under HECA's name in its updated 2012 PM2.5 Plan,[136] but this does not validate the use of this certificate for purposes of demonstrating compliance with the 24-hour NAAQS until the plan is officially approved by EPA.

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[130] *Ibid*.

[131] 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) ("the attainment demonstration [must] include[s] the emissions from such previously shutdown or curtailed emissions units"); NRDC, 571 F.3d at 1276.

[132] 51 Fed. Reg. at 43840.

[133] *See* generally *Emissions Trading Policy Statement: General Principles for Creating, Banking and Use of Emissions Reduction Credits*, 51 Fed. Reg. 43814, 43840 (Dec. 4, 1986)).

[134] SJVAPCD, Particulate Matter Plans; http://www.valleyair.org/Air_Quality_Plans/PM_Plans.htm.

[135] The 2008 PM2.5 Plan, Appendix D, Table D-5 lists S-3275-5 under the previous owners' name and certificate numbers S-2183-2 Big West. Not listed in the 2008 PM2.5 Plan is the predecessor of C-1058-5.

[136] The 2012 PM2.5 Plan, Appendix H, Table H-5 lists S-3275-5 under HECA's name.

IV.H.2 The District Must Demonstrate that Project Emissions Would Not Cause or Contribute to a Violation of Ambient Air Quality Standards

The District cannot allow HECA to use interpollutant offsets, *i.e.*, SOx ERCS to offset PM2.5 emissions, until it adequately demonstrates that emissions increases due to operation of the HECA Project will not cause or contribute to violations of the NAAQS or the CAAQS for PM2.5. SJVAPCD Rule 2201, Section 4.13.3.1 requires:

> Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.[137]

The District finds that the appropriate interpollutant ratio for SOx emission reductions to offset PM2.5 emission increases from the HECA Project is 1:1, based on chemical mass balance modeling and speciated rollback modeling as performed by the 2008 PM2.5 attainment plan.[138] However, EPA rejected this method in their 2011 action on the District's Revised 2008 PM2.5 Plan.[139] The District subsequently acknowledged EPA's criticism and in its more recent 2012 PM2.5 Plan – approved by the District on December 20, 2012 and the CARB on January 24, 2013 – determined, based on photochemical modeling, that PM2.5 emissions must be offset at a considerably higher SOx:PM2.5 interpollutant offset ratio of 4.1:1.[140] Yet, the PDOC fails to require this higher interpollutant offset ratio for PM2.5 emissions from the HECA Project.

The District argues that Rule 2201, Section 4.13.3.2,[141] restriction on the use of interpollutant offsets to those ratios established by EPA or approved into the SIP is not applicable because the proposed facility is not a major source of PM2.5.[142] This cannot be the case because the District is relying on the use of interpollutant offsets in its AAQI/HRA Report to support its conclusion that HECA Project emissions would not cause or make worse existing violations of PM2.5 ambient air quality standards.[143] In doing so, the District "shall … impose offset ratios equal to or greater than the

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[137] (Emphasis added).

[138] PDOC, p. 121.

[139] SJVAPCD, 2012 PM2.5 Plan, Adopted December 20, 2012, p. H-3; http://www.valleyair.org/Air_Quality_Plans/PM25Plan2012/CompletedPlanbookmarked.pdf.

[140] *Ibid*.

[141] The PDOC incorrectly refers to Section 4.13.2.2.

[142] PDOC, p. 121.

[143] PDOC, p. 121.

requirements of this rule."[144] The appropriate ratio for SOx:PM2.5 interpollutant offsets was determined by the District at 4.1:1 via photochemical modeling and the District plans to achieve further reasonable progress toward attainment of the PM2.5 NAAQS by using this offset ratio. The PDOC's willful ignorance of this ratio for the HECA Project defies and obstructs the federal Clean Air Act's mandate to achieve "reasonable further progress" toward attainment.[145] Even though EPA has not yet approved the 2012 Plan, the District may not approve a new project that does not meet the conditions it believes are necessary to achieve attainment with the PM2.5 NAAQS.

Further, the 4.1:1 interpollutant offset ratio was developed for bringing the air basin in compliance with the annual NAAQS of 15 $\mu g/m^3$. On January 15, 2013, EPA promulgated a lower annual NAAQS of 12 $\mu g/m^3$ which the PDOC fails to acknowledge. The District must address compliance with this new NAAQS as well as with the annual CAAQS for PM2.5 of 12 $\mu g/m^3$ and determine the appropriate offset ratio.

Finally, the HECA Project would also emit substantial amounts of ammonia, NOx, VOCs, and SOx which are precursors for the secondary formation of PM2.5.[146] The PDOC neither acknowledges nor models or mitigates secondary PM2.5. By accounting for and offsetting only direct emissions of PM2.5, the District fails to demonstrate how HECA would not contribute substantially to the existing substantial exceedances of the NAAQS and CAAQS for PM2.5 in the project area (24-hour background: 196 $\mu g/m^3$ and 22 $\mu g/m^3$ annual).

V. THE PDOC'S POTENTIAL TO EMIT ESTIMATES ARE NOT ADEQUATELY SUPPORTED, UNDERESTIMATE THE PROJECT'S IMPACTS ON AIR QUALITY, AND THE PROPOSED COMPLIANCE CONDITIONS DO NOT ENSURE COMPLIANCE WITH EMISSION LIMITS

At the core of the federal Clean Air Act are the potential to emit calculations. The permitting authority must calculate what the emissions from a new facility will be in order to determine whether the new facility constitutes a major source of air pollution and triggers BACT, lowest achievable emission rate ("LAER") or maximum achievable control technology ("MACT") requirements. To do so, the permitting authority must first determine each new emission unit's "potential" to emit regulated pollutants of

[144] SJVAPCD Rule 2201, Section 4.13.3.1 (emphasis added).

[145] Nonattainment plans must "require further reasonable progress," which is defined as "annual incremental reductions in emissions…for the purpose of ensuring attainment" of the NAAQS. 42 U.S.C. §§ 7502(c)(3), 7501. The first step is to compile a current inventory of actual emissions in the area and include "enforceable emissions limitations, and such other control measures, means, or techniques," including offsetting requirements. 42 U.S.C. §§ 7502(c)(3),(6); 7410(a)(2)(A), (I).

[146] SJVAPCD, 2012 PM2.5 Plan, p. 4-3.

concern, including but not limited to criteria pollutants and hazardous air pollutants ("HAPs"). The permitting authority then calculates the PTE for the entire project by adding up maximum potential emissions resulting from all emission units at the facility.[147] If this combined PTE for the stationary source – the District uses the term SPPE2 – for any pollutant is higher than the "significance threshold" for that pollutant identified in the applicable state implementation plan ("SIP"), then it triggers strict major source requirements for BACT and LAER.[148] If the pollutant is a HAP and the PTE is higher than the major source thresholds for individual or combined HAPs, then it triggers MACT requirements. If emissions are below these thresholds, then the facility is subject to the less stringent minor source requirements. Further, the emission rates determined through these calculations are also used in the modeling demonstration to determine air quality impacts for national ambient air quality standards, PSD increments, Class I, and health risk assessment purposes.

Here, the PDOC's PTE calculation for the Project did not include an adequate analysis of potential emissions resulting from unplanned startups, shutdowns, and malfunctions. In addition, as will be discussed below, the PDOC underestimated emissions of a number of pollutants from a number of units and omitted others. The District's failure to include all emissions in its PTE calculation violates the Clean Air Act's requirement of analyzing the facility's "maximum capacity to emit."

Under the Clean Air Act, the calculations underlying the draft permit, *i.e.*, the PTE calculations, must reflect the worst case emissions scenario and be enforceable from a practical perspective. The requirement that PTE be both maximum, or worst-case, and enforceable is reflected in the District's regulations. SJVAPCD Rule 2201, Section 3.27, states in relevant part:

> Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design

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[147] *See, e.g.*, SJVAPCD Rule 2201, Section 3.27 ("Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design.") and Section 4.10 ("Post-project Stationary Source Potential to Emit (SSPE2) shall be calculated, on a pollutant-by-pollutant basis, as the sum of the following: 4.10.1 The Potential to Emit from all units with valid Authorities to Construct or Permits to Operate at the Stationary Source, except for emissions units proposed to be shutdown as part of a Stationary Source Project.")

[148] A "significant" emissions increase in pollutant emissions includes, *inter alia*, an increase in the source's emissions of 100 tons/year of CO, 40 tons/year of SO_2, 40 tons/year of ozone precursors (VOCs or NO_x), 15 tons/year of PM_{10}, and "any emission rate" increase of any "regulated NSR pollutant" not expressly listed in the governing regulations in an area not determined to be in nonattainment for that pollutant. 40 CFR § 51.166(b)(23)(i); SJVAPCD Rule 2401 (incorporating 40 CFR § 52.21).

only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an enforceable permit condition.[149]

In short, this provision requires first that PTE reflect the maximum capacity to emit a pollutant. It requires second that, to the extent that the applicant or agency claims that maximum capacity to emit is constrained in any way, the constraint must be explicitly set forth in the permit as a *physical or operational limit* – *i.e.*, a specific limit on fuel, hours of operation, or pollution control equipment operating parameters – that is practicably enforceable.

Courts have emphasized the need to ensure that any constraints assumed on potential to emit are grounded in enforcement reality.[150] The *Louisiana Pacific* court described PTE as "the cornerstone of the entire PSD program," and observed that allowing illusory and unenforceable limits to curtail PTE would create a loophole that could effectively wipe out PSD requirements entirely.[151] The same can be said of the MACT program with its parallel structure and process.

To be enforceable, a permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for the District, CEC, EPA, and citizens to determine whether the facility is complying with the condition.[152] Under the District rules, relevant case law, and EPA guidance,[153] the only limits that render a design limitation on emissions enforceable for purposes of PTE are specific restrictions on operation and design set forth in the permit, adherence to which can be verified by authorities.

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[149] Emphasis added.

[150] *United States v. Louisiana Pacific Corp.*, 682 F. Supp. 1122 (D. Colo. 1987). The specific holding of *Louisiana Pacific* – that limits on PTE must be federally enforceable – has been overruled by authority stating that the limits may also be "enforceable as a practical matter." However, the basic principles concerning PTE articulated in *Louisiana Pacific* remain standing. *See National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 2004) (holding that limits on PTE must be enforceable as a practical matter but need not necessarily be federally enforceable). *See also Weiler v. Chatham Forest Products*, 370 F.3d 339, 241 (2d Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels.")

[151] 682 F. Supp. at 1133.

[152] *See Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995).

[153] SJVAPCD Rule 2201, Section 3.27; *Louisiana Pacific*, *supra* and *Weiler*, *supra*; Terrell Hunt, Associate Enforcement Counsel, EPA, Air Enforcement Division, and John Seitz, Director, EPA, Stationary Source Compliance Division, *Guidance on Limiting Potential to Emit in New Source Permitting*, (June 13, 1989) ("EPA PTE Guidance").

The requirement that PTE calculations be enforceable through adequate permit limits was recently reaffirmed by the EPA Administrator in her objection to the Title V permit for BP's Whiting facility.[154] In that case, EPA agreed with the argument that the permit conditions were inadequate because they "require monitoring only, and do not specify measures by which emissions will be limited to prevent their exceeding the PSD/NNSR significance levels, should monitoring show that emissions exceed those levels." The measures necessary to limit the facility to the PTE calculations were not required by the permit "and, therefore, do not constitute federally enforceable limits that hold the facility's PTE below the … significance thresholds."[155]

In the present case, the PDOC's PTE calculations do not represent worst-case conditions and, further, the PDOC's compliance conditions do not assure compliance with the PTE as calculated, as discussed in the following comments for criteria pollutants and GHGs and Comment VII for HAPs.

V.A The PDOC's Potential to Emit Estimates Are Based on Unsupported Assumptions and the Applicant Admits that Project Design Is Not Finalized

The PDOC's estimates of the Project's PTE – and resulting conclusions regarding, for example, applicability of PSD or impacts on air quality and public health – are based on numerous assumptions regarding material balances, process streams, emission factors, etc. Many of these assumptions are unsupported in the record; others rely on information provided by the gasifier manufacturer MHI or by vendors for other equipment without being supported by vendor guarantees. This may not be as troublesome for review of a standard natural gas-fired combined cycle gas turbine facility where all equipment components are well known; however, for review of the HECA Project, which is a one-of-a-kind facility with new equipment and components that have never been tested before or never before in this combination, it is unacceptable. For example, the proposed MHI gasifier is a new type of oxygen-blown dry-feed gasifier with a two-stage operation that has never been tested before on this scale or the range of fuel blends that the facility expects.[156]

Finally, the PDOC's emission calculations and ambient air quality modeling rely on information provided by the Applicant that are not supported by vendor guarantees or credible emission factors derived via source tests at similar facilities and similar

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[154] EPA, Order Responding to Petitioners' Request that the Administrator Object to Issuance of State Operating Permit, *In re BP Products North America, Inc. Whiting Business Unit* (October 16, 2009).

[155] *Ibid*, p. 8.

[156] *See*, for example, HECA Response to Sierra Club Data Request No. 16.b: "… demonstration at scale must be incorporated into the experience base of MHI before the full range of feedstock flexibility can be determined ad guarantees can be made."

feedstocks. As such, many of the PDOC's assumptions are unsupported. Some examples include but are not limited to:

- Neither the PDOC nor the Application provide vendor guarantees to support emission factors, pollutant concentrations in exhaust gas, duration of various startup/shutdown phases, and other information "estimated" by the gasifier manufacturer MHI used to estimate criteria pollutant emissions from the HRSG and coal dryer during normal operations as well as during startup and shutdown.[157]

- The amount of mercury volatilized in the feedstock dryer was estimated by the equipment designer and manufacturer MHI and apparently provided to the Applicant in proprietary and confidential heat and material balances.[158] Unless MHI provides a vendor guarantee for the amount of mercury volatilized in the feedstock dryer, the PDOC cannot rely on the mercury emission rate for the feedstock dryer.

- Emission factors for ammonia emissions for the high pressure ("HP") and low pressure ("LP") absorber vents and the urea pastillation unit were derived from information provided by Casale Fluor for a different project, the SCS Puregen One project, and proportionally scaled for the HECA Project capacity. The vendor "expects" that the HECA Project would meet the assumed combined ammonia emission rate of 13.1 pounds per hour ("lbs/hr") for the HP and LP absorbers during normal and stable operations.[159] An expectation is not a guarantee and cannot be relied upon for emission rates from a process with no prior testing experience.

- For modeling of NO_2 concentrations resulting from Project emissions of NOx, the District makes a assumptions for the NO_2/NOx in-stack ratios for several pieces of equipment that are lower than the EPA-recommended default value of 0.5 that can be used without further justification. Several of the assumed ratios, specifically for the HRSG stack and coal dryer, are based on equipment vendor "engineering estimates with no written documentation or guarantees.[160]

[157] For example, Application, p. 3-19, and PDOC, pp. 206-207, and Appx. C, p. C-2.

[158] HECA Response to Sierra Club Data Request No. 38.w, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

[159] HECA Response to Sierra Club Data Request No. 38.p and Attachment 38-5 thereto, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

[160] PDOC, Appx. K, p. 47.

- Startup/shutdown operations of the flare assume 4,600 lbs/hour SO_2 in the acid gas vented to the SRU flare and a 99.5% removal efficiency for the caustic scrubber.[161] There is no support for these assumptions.

- Many other instances of unsupported assumptions are discussed throughout the comment letter.

Because this is a one-of-a-kind facility that employs equipment which has not been tested at the same scale before (*e.g.*, gasifier) or in this combination and control technologies whose assumed control efficiency is very high (*e.g.*, combined efficiency of activated carbon adsorption beds of 99%), all vendor- or Applicant-supplied emission factors and other assumptions must be adequately supported by vendor guarantees and incorporated into enforceable permit conditions.

Further, the details of the Project appear to be still under revision. For example, in an April 10, 2013 email to the CEC, more than eight weeks after publication of the PDOC, the Applicant's consultant URS Corporation ("URS") acknowledged that in addition to coal and petcoke the facility would require substantial amounts of limestone as a fluxant (on the order of 175 tons/day and 59,000 tons/year), which would require a separate fluxant unloading facility and a storage silo equipped with a baghouse.[162] Use of this fluxant would generate an additional 88 tons/day of gasification solids (an increase of 10%)[163] that need to be disposed of.[164] The need for a fluxant has never been mentioned before for the revised HECA Project (using the MHI gasifier), which was submitted for review to the CEC over a year ago. Emissions associated with fluxant delivery, handling, and storage and increased gasification solids disposal activities are consequently not accounted for in the PTE calculated by the PDOC.

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[161] PDOC, p. 60, and 1/10/2013 HECA Updated Emission Data, "Flares – Emissions Summary" dated November 13, 2012, p. 11 of 32, pdf 44.

[162] Dave Shileikis, URS, Email to Robert Worl, California Energy Commission, Re: Requested Information Re: HECA, April 10, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-04-10_Applicant_URS_Email_Response_to_CEC_re_Requested_Information_about_MW_and_Limestone_Fluxant_TN-70376.pdf.

[163] (938 tons/day) / (850 tons/day) = 1.10.

[164] Dave Shileikis, URS, Email to Robert Worl, California Energy Commission, Re: Requested Information Re: HECA, April 10, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-04-10_Applicant_URS_Email_Response_to_CEC_re_Requested_Information_about_MW_and_Limestone_Fluxant_TN-70376.pdf.

The Applicant also acknowledges that it currently does not have a complete energy balance and states that it will take some time to prepare this balance.[165] At this point in time, the Applicant estimates that "[n]et output may range from 267–300 MW and gross output may range from 405–431 MW."[166] When the main material and energy balances for the HECA Project cannot even be relied upon and continue to be substantially revised, the Applicant's emissions estimates for the Project's various processes should be considered preliminary at best, especially when close to applicable thresholds and not adequately monitored. The District cannot accurately calculate the PTE for the Project, determine whether Project emissions exceed major source thresholds, or demonstrate that the Project complies with all applicable rules and regulations based on unreliable information that is still under revision. As such, the PDOC is premature and should be withdrawn until the Applicant is able to present detailed and stable material and energy balances as well as vendor guarantees that support all assumptions used for Project emission estimates.

V.B The Facility's Potential to Emit Is Underestimated and Emission Limits Are Not Adequately Enforced

As discussed in the comments below, the PDOC contains a number of potential to emit calculations that do not account for the facility's maximum potential emissions and many of the PDOC's emission estimates are not adequately translated into enforceable emission limits in compliance conditions. Sierra Club requests that the District revise the emission estimates for the HECA Project to address these substantial flaws, adequately establish the facility's PTE based on maximum potential emissions, and update its ambient air quality modeling and health risk assessment accordingly.

V.B.1 Flare Emissions during Unplanned Startup, Shutdown, and Malfunction Events Are Not Accounted For

Startup, shutdown and malfunction ("SSM") emissions must be strictly prohibited or included in the potential to emit.[167] A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flares due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, pressure surges, etc. The EPA recently objected to the proposed Title V and PSD

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[165] *Ibid*.

[166] *Ibid*.

[167] *Weiler v. Chatham Forest Products*, 370 F.3d 339, 341 (2d Cir. 2004); EPA, Order Responding to Petitioners Request that the Administrator Object to Issuance of State Operating Permit from the EPA Administrator regarding BP Products North America, Inc., Whiting Business Unit, Permit No. 089-25488-00453, October 16, 2009. *See also* Steven C. Riva, EPA, Region 2, Letter to William O'Sullivan, New Jersey Department of Environmental Protection, February 14, 2006.

permit for the Cash Creek coal-to-synthetic natural gas facility in Kentucky because, amongst other issues, the permitting agency's determination of potential to emit for the facility did not account for unplanned shutdown and malfunction emissions from the flare.[168] EPA also objected to the proposed Title V permit for the Kentucky Syngas facility for failing to account for unplanned shutdown and malfunction emissions from the flare.[169]

While the PDOC accounts for planned startup/shutdown emissions, it takes an inconsistent approach for estimating PTE for the facility's various emission units with respect to unplanned startup/shutdowns and malfunction emissions. For emissions from the CO_2 recovery and vent system (S-7616-24-0), the PDOC calculates annual emissions based on 21 days/year (equivalent to a cumulative 504 hours/year) of venting at full capacity, accounting for two planned startup events per year and seven unplanned events per year including four unplanned CO_2 compressor outages, one unplanned CO_2 pipeline outage, and two unplanned events where the CO_2-offtaker is unable to accept.[170] The PDOC translates these assumptions into a permit condition restricting venting to a cumulative 504 hours per rolling 12-month average. Similarly, emissions from the HRSG when firing on natural gas during unplanned equipment outages are estimated based on a maximum of 336 hours per year and restricted by a corresponding condition of compliance.[171]

In contrast, the PDOC calculates maximum annual emissions based on flaring events during two planned startup events per year only.[172] The amount of annual flaring estimated by the PDOC is almost trivial: 28 hours for the gasification flare (startup and shutdown only); 40 hours for the SRU flare; and 40 hours for the Rectisol flare.[173] While the PDOC acknowledges that all three flares may dispose of gases during

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[168] EPA, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012, pp. 15-16; found on the internet at: http://www.epa.gov/region07/air/title5/petitiondb/petitions/cashcreek_response2010.pdf.

[169] EPA, In the Matter of Kentucky Syngas, LLC, Muhlenberg County, Kentucky, Title V/PSD Air Quality Permit No. V-09-001, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-9, June 22, 2012; found on the internet at: http://www.epa.gov/region07/air/title5/petitiondb/petitions/kentuckysyngas_response2010.pdf.

[170] PDOC, pp. 31, 81 and Appx. I, p. 9.

[171] PDOC, Appx. A, Condition 29, p. A-56.

[172] PDOC, pp. 58-61 and pp. 84-86.

[173] PDOC, pp. 84-86.

"emergency or upset" events,[174] the PDOC's calculations for flares do not account for emissions during any unplanned emergency events and therefore do not calculate maximum or worst-case PTE for the flares and the facility. Consequently, the PDOC's air quality modeling also did not include malfunction events and thus did not model the maximum offsite short-term impacts. This is particularly problematic for short-term SO_2 emissions and would likely result in exceedances of the 1-hour SO_2 NAAQS.

Because the PDOC restricts flaring events and sets emission limits only for planned flaring events and excludes malfunction events from the flaring emission limits,[175] exceedances of ambient air quality standards during malfunctions would never be discovered and reported.[176] The PDOC does also not contain any condition limiting the number and/or duration of unplanned startup/shutdown and malfunction events for either the gasifier, syngas scrubbing system, sour shift/low temperature gas cooling system, mercury removal system, or Rectisol acid gas removal unit which would vent to the three flares servicing the gasification unit (S-7613-30-0), the Rectisol unit (S-7616-31-0), and the sulfur recovery unit ("SRU") (S-7616-32-0).[177] Thus, flaring during upset conditions at these units could release large amounts of pollutants, without any restrictions. As malfunctions are by definition unplanned, the duration of the events and the amount and type of emissions could be very different than assumed for the planned startups and shutdowns.

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[174] *See* PDOC, pp 57-61: "Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment during upsets and emergencies." "Flaring will occur … during emergencies." "The gasification flare will dispose of excess gas … during unplanned power plant upsets or equipment failures." "Flaring of untreated syngas or other streams will … occur as an emergency safety measure during unplanned upsets or equipment failures." "The SRU flare will be used to safely flare … gas streams containing sulfur during unplanned upsets or emergency events." "The SRU flare will … oxidize gas releases during emergency or upset events." "The Rectisol flare will be used to safely dispose of low temperature gas streams during … unplanned events or emergency events." "The maximum capacity of the Rectisol flare is based on the total flow from an … equipment failure event, such as a major failure in the acid gas removal unit." PDOC, Appx. A, Compliance condition No. 24, pp. A-80, A-87, A-95: "Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility…" (Emphasis added.)

[175] PDOC, Appx. A, pp. A-80, A-87, A-95, Compliance condition No. 19: Total time of planned flaring shall not exceed 8 hours per day nor 40 hours per calendar year." No. 20: "During planned flaring events, no more than 430 MMBtu/hr shall be combusted." No. 21: "Emissions from the flare during pilot and other non-emergency operation shall not exceed any of the following… [emission limits]." No. 22: SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 15.0 lb/hr during other non-emergency combustion." (Emphasis added.)

[176] PDOC, Appx. A, pp. A-78-A-101.

[177] *See* PDOC, Appx. A, Compliance condition for Gasification System (S-7616-21-0), pp. A-21-A-26.

During unplanned flaring events, or malfunctions, syngas streams containing large amounts of sulfur could be sent to the flares including raw syngas, scrubbed syngas, shifted syngas, or sour syngas. For example, at full capacity, the acid gas vent to the SRU flare could emit up to 4,600 lbs/hour SO_2, *e.g.,* when the caustic scrubber experiences a malfunction.[178] The flares convert sulfur present in these syngas streams as H_2S and COS into SO_2, which could lead to exceedances of the 1-hour SO_2 NAAQS as well as short-term ambient air quality standards for other pollutants.

Unplanned releases due to emergency conditions have been widely documented in the coal gasification industry and are not rare occurrences. They occur as a result of harsh processing conditions unique to coal gasification due to high concentrations of substances that corrode, erode and foul processing equipment such as ash, slag, sulfur compounds, and various organic acids. These components cause overheating, plugging, corrosion, erosion, and fouling of common processing equipment such as heat exchangers, coolers, slag handling equipment, and pump, compressor rotors, impellers and blades; fouling and associated corrosion of heat exchangers and coolers.[179]

HECA claims that "[g]iven the reliability of the subject equipment, there are no anticipated malfunctions; therefore, no emissions associated with such events are included in the PTE."[180] In fact, contrary to HECA's assertion, there is likely to be considerable malfunction flaring at the HECA Project, especially during the first few years of operation, but this can also occur during mature operations. The facility must comply with all permit limits and not exceed PSD increments and NAAQS under all operating conditions. There has been no demonstration in the PDOC that this is feasible. In fact, by including a limit on natural gas firing for the HRSG for unplanned events of 336 hours/year,[181] the PDOC makes clear that substantial periods of malfunction of the gasification unit and/or other equipment involved in producing clean syngas are expected during which the HRSG would not receive and operate on clean syngas but

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[178] 1/10/2013 HECA Updated Emissions Data, "Flares – Emissions Summary," dated November 11, 2012, p. 11 of 32, pdf 44.

[179] Neville A.H. Holt, Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants, Materials at High Temperatures, v. 20, no. 1, pp. 1-6, 2003; W. Schellberg and others, World's Largest IGCC Celebrates 10th Anniversary, 25th Annual International Pittsburgh Coal Conference, September 29 - October 2, 2008; EPRI, Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions, December 2006; Neville A.H. Holt, IGCC Technical Status, Trends and Future Improvements, ACS Meeting, San Francisco, March 2000.

[180] HECA Response to Sierra Club Data Request No. 62, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-12_Applicants_Supplemental_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67706.pdf.

[181] PDOC, Appx. A, Condition 29, p. A-56.

instead would have to rely on natural gas as a backup fuel to keep the HRSG running.[182] Flaring emissions during these unplanned events must be accounted for.

For example, a reliability study by Siemens for the Taylorville Energy Center in Illinois indicates poor availability during the first two years of operation, 55 to 65% during the first year and 75 to 85% during the second year.[183] This indicates the potential for significant malfunction events during these first two years of operation.

The one operational IGCC plant in the world that uses the same MHI gasifier technology as HECA will use, the Nakoso IGCC in Japan, has a record of online availability that is not that different than that of other gasifier designs.[184] The Nakoso IGCC plant experienced availability of 30 percent in Year 1 and 60 percent in Year 2, only marginally better in its first two years of operation than IGCC plants that have been operational for nearly 20 years, such as the Tampa Electric Polk Power Station in Polk County, Florida, and the Wabash River Coal Gasification Repowering Project near West Terre Haute, Indiana.[185] The low availability is due in part to forced outages (aka malfunctions).

Regarding the availability of the Nakoso IGCC plant over time, HECA consultant URS states: "Except for a 4.5-month shutdown period following the 2011 earthquake and tsunami, this plant has been operating continuously (except for scheduled maintenance and inspection) on a wide range of coals from around the world (since operation began in 2007) … Cumulative operating hours since commissioning has

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[182] See, *e.g.,* PDOC, p. 38: "Firing of the turbine on natural gas backup fuel will be limited to a maximum of … 336 hr/yr of unplanned equipment outages." PDOC, Appx. C, p. C-1: "The MHI 501 GAC® … turbine model … will fire on natural gas as a backup fuel … during periods of unplanned equipment outages up to 336 hours per year—periods when hydrogen gas is not available because the hydrogen-producing equipment is out of service." PDOC, Appx. C-6: "The backup natural gas firing will occur … during periods of unplanned equipment outages (up to 336 hours per year)" and "The permittee requests to fire the turbine/HRSG on natural gas for a limited period of time up to 336 hours per year when the gasifier is unavailable…" PDOC, Appx. I: "Firing on the backup natural gas fuel is necessary … during periods of unplanned gasification equipment outages for up to 336 hours per year (equivalent to 2 weeks per year) when hydrogen-rich fuel is unavailable."

[183] Siemens Operations and Maintenance Reliability Availability Maintenance Analysis, Taylorville Energy Center, February19, 2010, p. 3; http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.5%20-%20Siemens%20Operations%20and%20Maintenance%20Reliability%20Availability%20Maintenance%20Analysis.pdf.

[184] *See*, for example, Electric Power Research Institute, John Wheeldon, IGCC 101, Advanced Coal Gasification Technologies Workshop, Kingsport, April 25 and 26, 2012; http://www.gasification.org/uploads/downloads/Workshops/2012/Wheeldon,%20Kingsport.pdf.

[185] Electric Power Research Institute, John Wheeldon, IGCC 101, Advanced Coal Gasification Technologies Workshop, Kingsport, April 25 and 26, 2012; http://www.gasification.org/uploads/downloads/Workshops/2012/Wheeldon,%20Kingsport.pdf.

exceeded 16,100 hours (as of April 2012)."[186] 16,100 hours operating hours from late 2007 through April 2012, excluding four and a half months for the tsunami outage, is 16,100 hours over approximately four calendar years (35,040 hours). Thus, the actual availability of the Nakoso IGCC plant through April 2012 averaged 46 percent availability over the first four full years of operation (through April 2012) ((16,100 hours)/(35,040 hours) = 0.46). Nakoso has definitely not been operating continuously. There is no reason based on the operating history at Nakoso to assume that HECA will not have frequent starts and stops due to forced outages.

It is typical for applications for gasification facilities to estimate malfunction-related emissions as a separate category from startup flaring emissions. For example, the application for the Southeast Idaho Power facility estimated the duration and frequency of events based on whether they were caused by upsets downstream, upstream, or at the acid gas removal unit, estimating a total of 92 hours of upsets per year.[187] Likewise, the FutureGen gasification project grouped and estimated upsets by source of the problem: the air separation unit, the gasifier, the acid gas removal unit, the Claus unit, or the power island; it further estimates annual upset frequency for each source type.[188] The permit application for the Medicine Bow, Wyoming, gasification project (which was also prepared by URS) estimates emissions from 48 hours of malfunction-related flaring per year.[189]

The application for the Power Holdings coal-to-synthetic natural gas ("SNG") project in Illinois also recognized that upset emissions will occur and made an effort to estimate those emissions. It found that gases sent to the flare during malfunction may be sent without cleanup. The Power Holdings application contains malfunction evaluations at many points, and it attempts to identify the requirements for including

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[186] HECA Responses to Sierra Club Data Request No. 116, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[187] Southeast Idaho Power, Permit Application, Appx. D, p. 34; http://www.deq.state.id.us/AIR/permits_forms/permitting/pcaec/app_d_0408.pdf.

[188] FutureGen Final Environmental Impact Statement, November 2007; Appx. E, pp. E-4 and E-5; http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/Appendix%20E%20-%20Air%20Modeling%20Protocol.pdf.

[189] Medicine Bow Fuel & Power LLC Industrial Gasification &Liquefaction (IGL) Plant, Carbon County, Wyoming, Prevention of Significant Deterioration Permit Application, December 31, 2007, Amended Permit Application, Appx. B (HP Flare Detail Sheet: 40 hours HP flare; LP Flare Detail Sheet: 8 hours LP flare); http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC/Ex%2015.DEQ's%20Motion%20for%20Summary%20Judgment.pdf.

malfunction emissions and specific actions for reducing them.[190] The Power Holdings application modeled various malfunction scenarios as follows:

> The malfunction cases were evaluated in AERMOD. The modeling was conducted for both daytime and nighttime malfunction conditions. The three malfunction scenarios modeled were:
>
> - Malfunction case 4 - Unplanned shutdown of one methanation unit, sweet syngas to SNG flare for 60 minutes.
> - Malfunction case 5 - Unplanned shutdown of one Rectisol unit, sour syngas to SNG flare for 22 minutes (modeled as a 60 minute event).
> - Malfunction case 6 - Unplanned shutdown of one WSA unit, acid gas to acid gas flare for 22 minutes (modeled as a 60 minute event).
> - Malfunction cases 4, 5, and 6 represent the worst case malfunction events. Each malfunction scenario was setup for 23 hours of normal operations with one hour operating under one of the above listed malfunction condition. This operating situation was model as if it occurs every day during the 5 year period. This approached ensured that the highest 2nd high for each PSD review pollutants was identified.[191]

Malfunction scenarios can be identified and planned for using, for example, fault tree analysis or failure mode effect analysis, to identify possible failure modes in design, operation or maintenance. These types of analyses are used to design the flare system itself. The Applicant must have conducted such analyses, *e.g.,* to determine maximum capacity of the flares during malfunction events and to estimate a total of 336 hours of operation of the CTG on natural gas during malfunction events. Thus, emissions from the flares during such malfunction events can be estimated and included in potential to emit calculations, and air quality modeling. However, the PDOC in this case does not include the information required to estimate these emissions.

V.B.2 Combustion Turbine Generator/Heat Recovery Steam Generator and Coal Dryer Emissions Are Underestimated and Emission Limits Are Not Enforceable

The PDOC's emission estimates for the HECA Project's HRSG and feedstock dryer were based on an "expected operating schedule of 8,000 hours of operations, two startups and shutdowns per year, and 2 additional weeks of natural-gas operations

[190] PSD Construction Permit Application for the Southern Illinois Coal Gasification to Synthetic Natural Gas (SNG) Facility, Prepared for Power Holdings of Illinois, Southern Illinois Coal to SNG Facility, October 17, 2007, Chapters 1 and 2.

[191] Power Holdings of Illinois, Permit Application, pp. 1-130 to 1-131.

other than startup and shutdown events."[192] The duration of the HRSG startup and shutdown events is assumed at 4.5 and 9 hours, respectively; the duration of the coal dryer startup and shutdown events is shorter and assumed at 4 hours each.[193] Thus, the PDOC's PTE calculations account for 8,363 hours of operation per year for the HRSG under the various permitted operating conditions.[194] The PDOC explained that this operating schedule was chosen because "hours that include startup and shutdown events will have higher NOx, CO, and VOC emissions than the normal operating condition with fully functioning SCR and CO oxidation catalyst."[195] There are a number of problems with the PDOC's assumptions which result in a considerable underestimate of the facility's PTE for several pollutants which are not adequately restricted by other permit conditions.

The PDOC arbitrarily assumes that the HRSG and coal dryer would not operate for a total of 397 hours of the year[196] (presumably for maintenance after the annual two planned shutdown events) and have zero emissions during this period. In other words, the PDOC assumes that each of the two planned shutdowns would require 198.5 hours or about 8.25 days of maintenance.[197] The PDOC contains no explanation for its assumption of downtime and it does not translate the "expected operating schedule" into enforceable permit conditions. Specifically, while the PDOC contains permit conditions limiting a) the number (2/year) and duration of startups and shutdowns for both the HRSG (4.5 hours and 9.0 hours) and the coal dryer (4.0 hours and 4.0 hours),[198] b) the duration of HRSG operation on natural gas during periods other than startup and shutdown events to 336 hours (14 days),[199] and c) monitoring for NOx and CO via continuous emissions monitoring systems ("CEMS")[200] to demonstrate compliance with daily and annual emission limits, the PDOC does <u>not</u> contain d) a restriction on the total number of hours under normal operating conditions for the HRSG and the feedstock dryer, e) a requirement that the units not operate for 397 hours per year, or f) continuous monitoring for SOx, PM10, VOC, and ammonia mass emissions (rather than demonstrating compliance by calculation and source testing). Maximum emission

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[192] PDOC, p. 28.

[193] *See* 1/10/2013 HECA Updated Emissions Data, "HRSG and Coal Dryer," pp. 2-4 of 22, pdf 35-37.

[194] (8,000 hours/year normal operation) + (2 × 4.5 hours/year HRSG startup conditions) + (2 × 9 hours/year HRSG shutdown conditions) + (336 hours on natural gas) = 8,363 hours/year.

[195] PDOC, p. 28.

[196] (8,760 hours/year) – (8,363 hours/year total operation of HRSG) = 397 hours/year.

[197] (397 hours/year idle) / (2 shutdowns/year) = 198.5 hours/event;
(198.5 hours/event) / (24 hours/day) = 8.27 days idle.

[198] PDOC, Appx. A, p. A-58, Conditions 40 and 41 for Unit S-7616-26-0.

[199] PDOC, Appx. A, p. A-56, Condition 29 for Unit S-7616-26-0.

[200] PDOC, Appx. A, p. A-61, Conditions 64 and 65 for Unit S-7616-26-0.

rates of pollutants from HRSG and coal dryer are not proportional for all operating scenarios but depend on the respective operating scenario. Thus, unless the PDOC includes enforceable permit conditions including monitoring for each pollutant, it must calculate the units' PTE for each based on the maximum or worst-case scenario.

The following table summarizes several operating scenarios that would be possible under the PDOC's permit conditions which would result in increased PM10, PM2.5, SO_2 and NH_3 emissions without increasing NOx or CO emissions. Because only NOx and CO emissions are required to be monitored directly via CEMS, these emission increases would not be detected.

Table 1: Combined PTE for HRSG and coal dryer under various operating scenarios

Variables	**PDOC**	**2 SU/SD, reduced downtime, no malfunctions**	**2 SU/SD, increased downtime, fewer malfunctions**	**1 SU/SD, increased downtime, no malfunctions**
Normal operation	8,000 hours/year	8,390 hours/year	8,155 hours/year	8,435 hours/year
Startup/shutdown events	2/year	2/year	2/year	1/year
Downtime	198.5 hours/event	171.5 hours/event	358 hours/event	312 hours/event
Fired on natural gas (other than during startup/shutdown)	336 hours/year	0 hours/year	100 hours/year	0 hours/year
Pollutant (tons/year)				
NOx	123.5	123.5	123.5	123.5
CO	101.7	101.5	101.5	95.9
VOC	17.5	17.3	17.3	17.2
PM10/PM2.5	59.6	**59.8**	**59.7**	**60.0**
SO_2	19.9	**20.0**	**20.0**	**20.1**
NH_3	88.9	**90.4**	**90.0**	**90.9**

Year = 12-month rolling average; SU/SD = startup/shutdown
Emissions were calculated based on the stated operating variables and otherwise relying on the Applicant's assumptions including emission factors

All these, and other, scenarios are realistic and possible under the PDOC's proposed compliance conditions. The District should determine maximum emissions from the HRSG and coal dryer for each pollutant under any operating scenario permitted under its compliance conditions to satisfy the PTE requirements of the Clean Air Act unless the PDOC is revised to include enforceable compliance conditions that would ensure that the PTE as estimated would not be exceeded. These revisions could either be enforceable permit conditions incorporating the exact assumed operating schedule, (*i.e.*, 2 startups/shutdown events per year, 397 hours of downtime, and 336 hours of firing natural gas at 80% load other than during startup/shutdown events) or, alternatively and preferably, require continuous emissions monitoring of PM10/PM2.5, SO_2 and NH_3 rather than demonstrating compliance via calculations.

Sierra Club recommends that the District require at the very least monitoring of PM10, PM2.5 and SO_2 via CEMS.

Finally, the PDOC's compliance conditions for the HRSG and coal dryer limit the number of startups and shutdowns to two each per calendar year.[201] This condition should be revised to clarify that the limitation to two startups and two shutdowns each includes both planned and unplanned events. The same condition should be repeated in the compliance conditions for the feedstock dryer (S-7616-20-0).

V.B.3 VOC Emissions from the CO_2 Vent Are Underestimated

The PDOC calculates annual emission rates for VOC emissions from the CO_2 recovery and vent system (S-7616-24-0) of 5,672 lb/year[202] on a methane basis[203] rather than for the actual VOC contained in the vent stream, *i.e.*, methanol. While the District may write permit conditions for VOC emission limits on a methane basis for purposes of determining compliance (which it did not), it must calculate the unit's PTE in tons/year based on the molecular weight of the VOC contained in the gas stream, not normalized to methane. Because the molecular weight of methane (16.04 g/mol) is only about half that of methanol (32.04 g/mol), the PDOC's emission calculations for the CO_2 recovery and vent system underestimates the unit's PTE for VOCs by a factor of two. Based on the molecular weight of methanol and otherwise relying on the PDOC's (Applicant's) assumptions, the revised PTE for the unit is 11,358 lbs/year and 5.68 tons/year of VOC (as methanol).[204] Hourly emission rates for methanol from the CO_2 vent and recovery system are equally underestimated; revised estimates are 22.5 lbs/hour of VOCs (as methanol).[205] (For a discussion of methanol as a HAP, *see* Comment VII.D.2) Because the PDOC's compliance condition for the CO_2 vent do not specify on which basis VOC emissions must be quantified[206] and the Applicant would presumably rely on the text of the PDOC and determine VOC normalized to a methane basis, this discrepancy in actual emissions and the calculated PTE would likely never be detected.

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[201] PDOC, Appx. A, Condition 41, p. A-58.

[202] PDOC, p. 93.

[203] PDOC, p. 54.

[204] 5,672 lbs/year) × (32.04/16.04) = 11,358 lbs/year;
(11,358 lbs/year) / (2,000 lbs/ton) = 5.68 tons/year.

[205] (17,584 lb-mol/hour) × (40 ppm methanol) × (32.04 lb/lb-mol) = 22.5 lbs/hour.

[206] *See* PDOC, Appx. A, Conditions for CO_2 Recovery and Vent System, pp. A-42-A-45.

V.B.4 Emission Estimates for the Auxiliary Boiler Improperly Exclude Startup and Shutdown Emissions

The Project would include a natural gas-fired auxiliary boiler (S-7616-25-0) that will provide steam for pre-startup equipment warm-up and for other miscellaneous purposes when steam from the Gasification Block or HRSG is not available.[207] The PDOC calculates emissions from the auxiliary boiler assuming a NOx concentration of 5 ppmvd.[208] The PDOC exempts startup and shutdown periods for the auxiliary boiler from compliance with this, and other, emission limits.[209] However, during a cold startup before the SCR system is fully operational, uncontrolled or partially controlled NOx emissions from the auxiliary boiler will be much higher than during normal operations). The PDOC's ambient air quality modeling and health risk assessment are also based on normal operations of the boiler without accounting for periods when the SCR system is not fully functional.[210] Thus, short-term modeled ambient concentrations do not reflect startup and shutdown emissions from the auxiliary boiler and may be considerably higher than presented in the PDOC. The District must require that emissions from the auxiliary boiler during startup and shutdown periods comply with the emission limits established in Condition 16 or provide a revised PTE and updated ambient air quality modeling that accounts for higher short-term emissions from the unit during startup and shutdown.

Further, the auxiliary boiler (S-7616-25-0) will have a design capacity of 230 MMBtu/hour and the PDOC restricts the maximum allowable heat input to 213 MMBtu/hour.[211] While the PDOC requires installation of a non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit, it does not contain an enforceable permit condition limiting heat input on an hourly basis to ensure that the boiler would not operate in excess of the 213 MMBtu/hour limit. Because short-term emissions from the auxiliary boiler were modeled based on 213 MMBtu/hour, the PDOC must include an enforceable condition to ensure that the unit is not operated in excess of this limit and to demonstrate compliance with Condition 17. Otherwise, the PDOC's emission calculations and ambient air quality modeling for the unit must be based on the maximum auxiliary boiler design capacity of 230 MMBtu/hour. Further, the PDOC should require in a permit condition that both annual and hourly records for the unit be submitted annually to the District for review.

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[207] PDOC, p. 14.

[208] PDOC, p. 55.

[209] PDOC, Appx. A, p. A-47, Condition 16.

[210] PDOC, Appx. K, pp. 18, 42, and 56.

[211] PDOC, p. 32, p. 55, and Appx. A, p. A-47, Condition 16.

V.B.5 Fugitive Emissions from Methanol Storage Tank Are Not Accounted For

The HECA Project would operate a Rectisol-based acid gas removal ("AGR") unit to selectively separate sulfur compounds and CO_2 from the shifted sour syngas. The Rectisol absorber would use chilled methanol as a physical solvent.[212] To supply makeup methanol to the AGR unit, the Project would need a methanol storage tank. In the proceedings before the CEC, the Applicant indicated that the methanol tank would have a capacity of 300,000 gallons and an annual turnover of 1.32 and would be equipped with a vent scrubber.[213] The PDOC is silent as to the construction, dimensions, capacity, or throughput of a methanol tank or the type and control efficiency of any control equipment that would be installed; in fact, neither the methanol tank nor the associated vent scrubber is even mentioned in the document. Neither the PDOC nor the Application account for methanol emissions from the methanol storage tank. Methanol is a VOC as well as a HAP and emissions from the methanol storage tank must be included in the facility's PTE.

Emissions from storage tanks consist of working losses and breathing losses (often referred to as standing losses) as well as roof landing losses for those tanks with internal floating roofs.[214] In the proceedings before the CEC, the Applicant stated that it determined uncontrolled working and breathing losses from a fixed-roof methanol tank with EPA's TANKS model and indicates that it assumed that 33,000 gallons per month would be pumped into the methanol tank (396,000 gallons/year equivalent to a turnover of 1.32).[215] The model runs and other input assumptions (tank dimensions, average liquid height, color, etc.) are not provided[216] and could therefore not be reviewed.

Methanol tanks are typically constructed as internal floating roof tanks. An internal floating roof tank has both a permanent fixed roof and a floating roof inside. In floating roof tanks, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operation. These tanks therefore have a considerably better control than simple fixed roof tanks, which, according to EPA, are

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[212] PDOC, p. 10.

[213] AFC, Table 2-15, p. 2-88 and HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

[214] *See* EPA, AP-42, Section 7.1: Organic Liquid Storage Tanks; November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

[215] *See* 1/30/2012 HECA Updated Emissions Data, "Methanol and Diesel Tanks," p. 24 of 25, pdf 145.

[216] *Ibid*.

the "minimum acceptable equipment for storing organic liquids."[217] The Applicant indicates that the TANKS model run, which it claims was based on a fixed roof tank, resulted in uncontrolled working losses of 80.8 lbs/month methanol and uncontrolled breathing losses of 1,277.7 lbs/month methanol. These results indicated that the Applicant indeed assumed an internal floating roof, as a fixed roof tank would have resulted in considerably higher uncontrolled emissions.

When an internal floating roof tank is emptied to the point that the roof lands, there is a period where the roof is not floating and other mechanisms must be used to estimate emissions. These emissions continue until the tank is refilled to a sufficient level to again float the roof.[218] In response to a data request by Sierra Club in the proceeding before the CEC, the Applicant declined to estimate roof landing losses stating that "[r]oof landing losses apply only to floating roof tanks, whereas all the tanks at the site have fixed roofs, so this does not apply."[219] As stated before, all internal floating roof tanks also have a fixed roof and the Applicant's estimates indicate that it used an internal floating roof tank. If not, the model runs must be revised as a fixed roof tank cannot be permitted as BACT in the District. If an internal floating roof tank is used, roof landing losses must be included.

The Applicant then calculates a minuscule amount of controlled methanol emissions of 3.72 lbs/year from the Project's methanol tank, assuming that the tank vent scrubber has a control efficiency of 99.977.[220] This extraordinarily high vent scrubber efficiency was calculated assuming a pre-scrubber methanol concentration of 17.76% and a post-scrubber methanol concentration of 40 ppm which was "provided by Fluor."[221] None of these assumptions, including the calculated scrubber control efficiency, is supported by any documentation or vendor guarantee or incorporated into the PDOC by enforceable compliance conditions. These calculations simply rest on unsupported assumptions.

The District must review the Applicant's assumptions and issue a revised PDOC that contains a proper description of the methanol tank and its associated control equipment, estimate methanol emissions based on properly supported assumptions, and include enforceable permit conditions to assure compliance with calculated

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[217] EPA, AP-42, Section 7.1: Organic Liquid Storage Tanks; November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

[218] *Ibid*.

[219] HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

[220] *Ibid* and 1/30/2012 HECA Updated Emissions Data, "Methanol and Diesel Tanks," p. 24 of 25, pdf 145.

[221] (1)-(40/1,000,000 post-scrubber)/(17.76% pre-scrubber) = 99.977%.

emission limits including tank throughput monitoring, monitoring of the methanol vapor flow rate to the scrubber, scrubber performance tests, inspections, etc. (For example, the construction permit for the Tenaska Energy Center includes six pages of permit conditions for the proposed methanol storage tank alone.[222])

V.B.6 Fugitive Emissions from Diesel Stored with Emergency Generator and Diesel Fire Pump Are Not Accounted For

The Project would have two diesel-powered emergency generators (S-7616-38-0, S-7616-39-0) and one diesel-powered firewater pump (S-7616-40-0).[223] The Applicant states that diesel fuel would be stored as an integral part of the skids.[224] As with the methanol storage tank, the PDOC does not include fugitive emissions from these internal tanks in the calculation of the Project's PTE.

V.B.7 Fugitive Equipment Leaks Are Not Adequately Supported and Are Underestimated

Equipment leaks are emissions from piping components and associated equipment including valves, connectors, pumps, compressors, process drain, and open-ended lines, as opposed to large point sources of emissions coming from stacks. These components leak small amounts of the gases and liquids they handle through seals and screw fittings. Thus, they are commonly called fugitive emissions or fugitive leaks. These emissions include compounds found in the streams that pass through the components – CO, VOCs, H_2S, total reduced sulfur ("TRS"), methane, CO_2, and numerous individual HAPs, such as methanol, and COS. The collective leaks from these fugitive components can add up to a large amount of emissions in the aggregate because there are thousands of them.

a) TOC Weight Fraction in Process Streams Is Not Supported

The PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based the average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit (process streams #1 methanol, #2 syngas, #3 shifted syngas, #5 propylene, #6 sour water, #7 H_2S-laden methanol, #8 CO_2-laden methanol, #9 acid gas, #10 ammonia-laden gas, #11 sulfur,

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[222] Illinois Environmental Protection Agency, Construction Permit – PSD Approval, Christian County Generation, LLC, Location: Taylorville Energy Center, Application No. 05040027, ID No. 021060ACB, April 30, 2012, pp. 99-104; http://yosemite.epa.gov/r5/in_permt.nsf/93a421690cb50df18625762300769ee3/eb1614a58f87ae9686257b640049b94f/$FILE/ATTM5GSQ/05040027.pdf .

[223] PDOC, Appx. A, pp. A-133-A-144.

[224] HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

#12 SRU tail gas) and the fertilizer complex (process streams #13 through #21).[225] The respective weight fractions have no support in the record as to how they were derived, what their expected variability is, and how reliable these numbers are, but are merely presented as fact.

Review of these TOC weight fractions show that even minor variability in some process areas would turn the HECA Project into a major source of hazardous air pollutants. For example, for the gasification unit, the Applicant assumed a methanol weight fraction of 79.0583% in process stream #7, the H_2S laden methanol stream, and 72.3853% in process stream #8, the CO_2-laden methanol stream. Increasing the methanol weight fractions in these process streams by less than 3% each (to 82% and 75%, respectively, and assuming a correspondingly lower CO_2 content), and otherwise relying on the Applicant's assumptions, would result in an increase of controlled fugitive methanol emissions from equipment leaks – and thus the facility's PTE for VOCs – by 0.18 tons/year.[226] In addition to increasing the PTE for VOCs, this increase is sufficient to increase total Project emissions of methanol from 9.83 tons/year to 10.01 tons/year, *i.e.*, over the 10 tons/year major HAP threshold for individual HAPs. (*See* also Comment VII.D.2).

This calculation illustrates how important the accuracy of the Applicant's assumptions is. The very precise weight percentages (six significant digits) of pollutants in various process streams relied upon by the Applicant are at odds with the general lack of experience with the equipment and layout of the project and the ever shifting information presented elsewhere.

b) SOCMI Emission Factors Are Not Applicable

The PDOC states that potential fugitive VOC emissions from piping components were estimated using emission factors from EPA's 1995 *Protocol for Equipment Leak Emission Estimates*.[227] This guidance provides separate sets of emission factors for equipment components for various industries including refineries and the synthetic organic chemical manufacturing industry ("SOCMI"). Here, the PDOC relies on SOCMI emission factors to calculate fugitive emissions for the gasification complex as well as the manufacturing complex, rather than the considerably higher emission factors developed for refineries. Yet, the PDOC provides no discussion of or demonstration that SOCMI emission factors are, in fact, applicable to the HECA Project but instead appears to rely on the following unsupported statement by the Applicant:

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[225] 1/10/2013 HECA Updated Emissions Data, *see* note above table "Area Speciation" in "Fugitive Emissions – Gasification Unit," p. 19 of 25, pdf 140.

[226] Our calculations are based on formulas found in HECA's emissions spreadsheets. These spreadsheets were designated as confidential and provided to Sierra Club only after Sierra Club signed a nondisclosure agreement.

[227] PDOC, p. 36.

> According to the USEPA document (USEPA, 1995a), the criteria for determining the appropriateness of emission factors are based on the following: (1) process design; (2) process operation parameters; (3) types of equipment used; and (4) types of material handled. Based on these criteria, the Project processes are most similar to a SOCMI plant. Therefore, the SOCMI fugitive emission factors from USEPA are used in the fugitive emission calculations.[228]

The Applicant provides no further demonstration which process designs, process operation parameters, types of equipment used, and types of material handled at the HECA Project are "most similar" to a SOCMI plant or provides any evidence that the physical and chemical composition of IGCC process streams is similar to that of process streams in the synthetic organic chemical industry. A coal gasification facility such as the HECA Project is not a SOCMI facility; in fact, it appears that a gasification facility has a lot in common with a refinery: Both refineries and gasification plants, for example, convert fossil fuels (petroleum, coal) into end products used to generate fuels (gas, gasoline) under similar conditions of pressure and temperature. They both also use many of the same unit processes, including sour water stripping, sulfur recovery, tail gas treating, sulfur tanks and loading, thermal oxidizers, and acid gas removal systems. Finally, a gasification facility does not manufacture "synthetic organic chemicals."

The amount of total organic compound ("TOC") emissions from equipment leaks depends on the chemicals being processed for many reasons. Process streams with different chemical (*e.g.*, polarity) and physical properties (*e.g.*, temperature, pressure) will produce different TOC emission factors, *i.e.*, the escaping tendency of chemicals inside processing units depends upon the composition of the contained material. The synthetic organic chemical industry is largely characterized by smaller equipment and more batch processes that lend themselves more readily to improved control than the processes that would be used at the HECA Project. An IGCC plant uses larger equipment operating continuously at higher temperatures. In its applicable AP-42 guidance section, EPA voiced concerns regarding potential fugitive leaks emissions from gasifiers and associated equipment stating that "leaks may be more severe from pressurized gasifiers and/or gasifiers operating at high temperatures."[229]

The SOCMI factors were developed by EPA based on field measurements at 30 individual chemical process units representing a cross-section of the synthetic organic chemicals industry and screening and bagging data were obtained from

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[228] Application, p. 5-12.

[229] EPA, AP-42, Section 11.11 Coal Conversion; http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s11.pdf.

19 ethylene oxide and butadiene producers.[230] Regarding the applicability of these emission factors to other industries, EPA concludes "in most cases, SOCMI emission factors and correlations are applicable for estimating equipment leak emissions from the polymer and resin manufacturing industry. This is because, in general, these two industries have comparable process design and comparable process operation, they use the same types of equipment, and they tend to use similar feedstock."[231] The polymer and resin manufacturing industry, which manufactures plastics, glues, fiberglass backing material, fiber optics components, and other physical materials, is not similar to coal gasification in terms of types of equipment or feedstocks used. Further, SOCMI emission factors were developed for processes used to generate synthetic organic chemicals such as acetaldehyde, acetone, and phenol,[232] not for processes used to generate syngas and its byproducts, *e.g.*, air separation, raw syngas production, syngas conditioning, acid gas removal, sulfur recovery, methanation, and dehydration.

Coal gasification facilities are not chemical plants, which have had to keep tighter leak standards far longer than other industries as a practical matter due to the extremely hazardous nature and high value of the chemicals they handle. First, SOCMI facilities handle materials of greater value than those at an IGCC facility, providing an incentive to minimize equipment leaks. Second, a SOCMI facility typically handles highly volatile, toxic and hazardous substances, which must be minimized to prevent worker exposure. These conditions dictate design and operating practices at these facilities to minimize releases. The PDOC contains no evidence of similar concerns at the HECA Project. In fact, it fails to even consider the use of leakless and low-leak technology as BACT. (*See* Comment VI.H). These equipment components would routinely be used in the synthetic organic chemical industry to preserve feedstock and protect workers. These differences would result in lower emissions at a SOCMI facility than at a gasification facility such as the HECA Project without similar concerns. Most processing units in IGCC facilities operate at higher temperature and pressures than typical SOCMI processes, resulting in higher component failures and thus higher leaks. In short, the emission factors developed for SOCMI facilities are not relevant to the gasification of coal and production of syngas and underestimate fugitive emissions from the HECA Project.

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[230] EPA, Protocol for Equipment Leak Emission Estimates, Report EPA-453/R-95-017, November 1995, Sections 2.2.2 and 2.3.1 and Table 2-1 (hereafter "Protocol for Equipment Leak Emission Estimates"); www.epa.gov/ttnchie1/efdocs/equiplks.pdf; and EPA, Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs, Report EPA-450/3-82-010, April 1982 (hereafter "EPA 4/82"), Section 2.1.6 and Table 2-12; http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009YVL.txt.

[231] Protocol for Equipment Leak Emission Estimates, p. 2-6.

[232] *See* EPA 4/82, Table 2-12.

V.B.8 Emissions Associated with Fluxant Delivery, Storage, and Handling Are Not Accounted For

As discussed above, the PDOC does not include emissions associated with the delivery, storage and handling of the approximately 175 tons/day and 59,000 tons/year of limestone fluxant and the 10% increase in emissions resulting from the additional 88 tons/day of gasification solids that are generated by using fluxant. The District must also develop adequate compliance conditions restricting the quantity of daily and annual fluxant use and number of deliveries.

V.B.9 On Site Fugitive Dust Emissions from Paved Roads and Wind Erosion Are Not Accounted For

HECA did not take into account fugitive emissions to determine its potential to emit and major source status as required by the Clean Air Act and local rules. Sources that fall in one of the 28 named industrial source categories must take into consideration fugitive emissions, *i.e.*, emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening" when determining whether emissions reach the 100 ton/year emissions threshold to determine major source status.[233] The HECA Project falls within the source category "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input" and must therefore account for fugitive emissions when determining potential to emit and major source status.[234] The PDOC's determination of potential to emit and major source status for purposes of PSD does not account for particulate matter emissions associated with fugitive entrained road dust generated by on-site vehicle movement nor for particulate matter emissions from wind erosion.[235] On-site fugitive dust emissions can be substantial and must be included in the PTE and the PSD major source determination for PM, PM10, and PM2.5.

a) Paved Roads

HECA estimated fugitive dust PM10 and PM2.5 emissions from onsite paved roads in in its Application (and provided substantially revised estimates in its 1/10/2013 HECA Updated Emissions Data),[236] yet, these estimates were not incorporated into the PDOC's PTE. Sierra Club finds that the paved road PM10 and PM2.5 emissions calculated by HECA use incorrect inputs and result in substantially

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[233] 40 CFR §§ 52.21(b)(1)(iii), (b)(1)(c)(iii); *see* SJAPCD Rule 2410 (incorporating 40 CFR Part 52.21 into the SIP).

[234] 40 CFR § 52.21(b)(1)(i)(c)(iii)(z).

[235] *Compare* PDOC, table "Post-Project Stationary Source Potential to Emit [SPPE2] (lb/year)", p. 93, and table "PSD Major Source Determination: Potential to Emit (tons/year)", p. 96.

[236] 1/10/2013 HECA Updated Emissions Data, "Fugitive Dust on Paved Road," p. 16 of 17, pdf 120.

underestimated emission rates. Sierra Club previously commented on PM10 emissions from paved roads[237] and revises and expands its comments as follows:

HECA used an equation obtained from EPA's AP-42, Section 13.2.1, for paved roads to calculate particulate matter (fugitive dust) emissions from onsite vehicle traffic.[238] This equation is as follows:

E_{ext} = $[k(sL)^{0.91} \times (W)^{1.02}] \times [1-P/4N]$

where: E_{ext} = emission factor in the same units as k

k = particle size multiplier; 0.25 g/vehicle mile traveled (VMT) for PM2.5; 1.0 g/VMT for PM10.[239]

sL = road surface silt loading (g/m^2)

W = average weight of vehicles (tons)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

N = number of days in the averaging period (*e.g.*, 365 for annual, 91 for seasonal, 30 for monthly).

The values used for any of the variables in the above equation, k, sL, W, P, and N, will have an impact on the final result, *i.e.*, the calculated particulate matter emission rates. Our review of HECA's paved road fugitive dust PM10 and PM2.5 emission calculations finds that the key inputs to this equation are greatly underestimated.

- The PM10 and PM2.5 emission calculations use an inappropriate value for silt loading for onsite vehicle travel on paved roads.

- The 24-hour PM10 and PM2.5 emissions from paved roads inappropriately included a rainfall correction.

- The PM10 and PM2.5 emission calculations use inappropriate vehicle weights for trucks traveling onsite.

Each of these inputs, including the necessary corrections to the emission rate calculations are discussed below.

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[237] Andrea Issod, Sierra Club, Letter to Dave Warner, SJVAPCD, and Robert Worl, CEC, Re: Preliminary PM Modeling Comments on the PDOC for the HECA Project (08-AFC-08A), April 26, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-26_Sierra_Club_Comments_on_PDOC_TN-70503.pdf.

[238] *Ibid*.

[239] *Ibid*.

Silt Loading

Fugitive dust emissions from paved roads have been found to vary with the "silt loading" present on the road surface, which is the amount of particulate matter per paved surface area. Here, the Applicant assumed a silt loading value of 0.031 grams per square meter ("g/m^2"), which is the default value from URBEMIS 9.2 (URBan EMISsions Model) for Kern County.[240] This value is entirely inappropriate for determining fugitive entrained road dust emissions for the HECA Project site for a number of reasons and substantially underestimates particulate matter emissions.

First, the default silt loading value for Kern County from URBEMIS was developed to represent vehicle travel on all types of public roads including freeways, arterials, collector, local and rural roads throughout the county. As such it is appropriate for vehicle travel on public roads throughout the county, not for onsite roads at an industrial site whose silt loading is largely attributable to dust generated by material handling on site, including truck loading and unloading. EPA has developed silt loading values for industrial sites, which are included in the same AP-42 guidance the Applicant relied upon for the equation, *i.e.*, Section 13.2.1 *Paved Roads*. Table 13.2.1-3, *Typical Silt Content and Loading Values for Paved Roads at Industrial Facilities*, in this document tabulates ranges and mean silt loading values measured for eight different industries at 19 sites. The measured silt loading values at these industries range from 0.05 g/m^2 measured at a corn wet mill to 400 g/m^2 at a copper smelting facility with mean values ranging from 1.1 to 292 g/m^2.[241] Thus, HECA assumes a silt loading value that is lower than any of the values measured at other industrial facilities. Sierra Club requested that the Applicant provide emission estimates from on-site paved roads based on an appropriate silt loading value for paved roads at industrial facilities. The Applicant declined claiming that "…the AP-42 table referenced for paved roads at industrial facilities (Table 13.2.1-3) is not applicable to the HECA Project. The listed facility types are extremely different from the HECA Project (*e.g.*, copper smelting, sand and gravel processing) and would significantly overestimate silt loading." The Applicant does not provide any reasonable explanation for using a silt loading value for public paved roads instead.[242] Such lack of a reasonable explanation lead EPA recently

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[240] *Ibid*.

[241] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p. 13.2.1.10.

[242] The Applicant falsely claims that Sierra Club endorsed the default silt loading value for Kern County by taking the following statement in Sierra Club Data Request 27 out of context: "The silt loading default value used in URBEMIS 9.2 applies only to operational traffic associated with a project…" This data request addressed HECA's estimates of entrained road dust emissions during the construction phase of the Project pointing out that the default factor in URBEMIS is provided for estimating fugitive dust emissions resulting from vehicle movement on public paved roads during the operational phase of a project and is not appropriate for estimating paved road dust emissions during construction of the HECA

to object to a permit for the Cash Creek Generation Project, specifically because the permit record lacked a reasonable demonstration that the assumed silt loading value assumed for the project site of 0.4 g/m^2 was appropriate.[243]

Second, to the extent that onsite silt loading is affected by dust tracked-in from roads leading to the Project site, the roads surrounding the HECA site are rural roads surrounding agricultural land and as such have much higher silt loading values than the assumed default value. CARB developed a table of silt loading values for various types of roads in California ranging from freeways to rural areas. The CARB-reported silt loading values are averages of silt loadings measured by Midwest Research Institute in the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Quality Management District.[244] These silt loading values were used by CARB for the District' 2003 PM10 State Implementation Plan.[245] For rural roads, such as those surrounding the Project site, CARB derived a silt loading value of 1.6 g/m^2, which is over 50 times higher than the value used by the Applicant.[246]

Third, the default silt loading value for Kern County from URBEMIS already accounts for the county-specific rainfall correction, which the Applicant then erroneously applies again.[247] (More on rainfall correction below.)

Finally, AP-42 highly recommends the collection and use of site-specific silt loading data.[248] Where a source cannot obtain site-specific data, AP-42 recommends the selection of an appropriate *mean* value from the table listing silt loadings for industrial roads.[249] However, use of a mean value reduces the quality rating, *i.e.*, the confidence in the emission estimates, by two levels.[250]

Project. At no point did Sierra Club suggest that the default silt loading value in URBEMIS for public roads is appropriate for calculating on-site emissions from HECA's industrial project site.

[243] EPA, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012, pp. 27-28.

[244] CARB, Emission Inventory, Section 7.8 – SJV, Entrained Paved Road Dust, Paved Road Travel, June 2006; http://www.arb.ca.gov/ei/areasrc/PMSJVPavedRoadMethod2003.pdf.

[245] *Ibid*.

[246] This silt loading rate is not corrected for rainfall, which is appropriate for determining short-term emission rates for PM10 and PM2.5 emissions from paved roads. For estimates of annual emissions, a rainfall correction factor is appropriate.

[247] *See* "P = 36 days/year Buttonwillow Station 1940-2011, WRCC" in 1/10/2013 HECA Updated Emissions Data, Fugitive Dust on Paved Road, p. 16 of 17, pdf 120.

[248] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p. 13.2.1-9.

[249] *Ibid.*

[250] *Ibid.*

Correcting for the underestimated silt loading value has a profound effect on emission estimates for fugitive road dust. For example, instead of using the default value for silt loading of public paved roads in Kern County of 0.031 g/m^2, using the lowest mean value reported in AP-42 for any of the investigated industries of 1.1 g/m^2 (corn wet mills) increases emission estimates by a factor of about 26[251]; using the highest mean value determined for any industry of 292 g/m^2 (copper smelting operations) increases emission estimates by a factor of about 4,134.[252] The PDOC must provide a reasoned explanation which silt loading value it will choose to estimate fugitive dust emissions from HECA and include enforceable compliance conditions that will ensure that the calculated PTE for the facility is not exceeded. Permits for other industrial facilities including gasification plants frequently require measurement of on-site silt loading to demonstrate compliance. For example, the PSD permit issued for the Power Holdings of Illinois gasification facility includes extensive permit conditions for such measurements[253] as does the PSD permit for the Taylorville Energy Center gasification facility.[254]

Rainfall Correction

Sierra Club notes that the equation provided by AP-42 incorporates a rainfall correction factor under the simplifying assumption that annual (or other long-term) average emissions are inversely proportional to the frequency of measurable precipitation by application of a precipitation correction term.[255] Inclusion of this rainfall correction factor is only warranted for annual average emissions, not for short-term emissions. The Applicant incorrectly estimates short-term PM10 and PM2.5 emissions from paved roads using a yearly total of 36 rain days per year (in addition to incorrectly using the rainfall correction on an already rainfall-corrected silt loading

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[251] $(1.1)^{0.91}/(0.031)^{0.91} = 25.74$.

[252] $(292)^{0.91}/(0.031)^{0.91} = 4{,}133.89$.

[253] *See* Condition 4.8.8 ("…shall conduct measurements of the silt loading on various affected roadway segments and parking areas as follows… using the "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. A series of samples shall be taken to determine the average silt loading and address the change in silt loadings as related to the amount and nature of vehicle traffic and implementation of the operating program.") in Illinois Environmental Protection Agency, Construction Permit – PSD Approval, NSPS Emission Units, Power Holdings of Illinois, LLC, Application No. 07100063, ID No. 081801AAF, October 26, 2009; http://www.epa.state.il.us/public-notices/2009/power-holdings/final-permit.pdf.

[254][254] *See* Condition 4.11.8 in Illinois Environmental Protection Agency, Construction Permit – PSD Approval, Christian County Generation, LLC, Location: Taylorville Energy Center, Application No. 05040027, ID No. 021060ACB, April 30, 2012; http://yosemite.epa.gov/r5/in_permt.nsf/93a421690cb50df18625762300769ee3/eb1614a58f87ae9686257b640049b94f/$FILE/ATTM5GSQ/05040027.pdf.

[255] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-5.

value). This underestimates maximum daily emissions because there are many days in Kern County when there is no rainfall.

Truck Weight

Vehicle weights are the other component of the AP-42 emission factor for calculating PM10 and PM2.5 emission rates from paved roads. It is the average vehicle weight that is used for the emission calculation (usually the average of loaded and unloaded truck weights).[256] The Applicant's emission estimates are incorrect.

First, the Applicant's paved road PM10 and PM2.5 emission calculations incorrectly calculate emissions separately for each type of vehicle on site, *e.g.,* operation and maintenance vehicles with an average weight of 3 tons and for large trucks with an average weight of 17.5 tons. This approach is incorrect because the equation calls for a fleet-average weight and should not be used for separate weight classes. EPA in its AP-42 guidance notes that the equation "calls for the *average weight of all vehicles traveling the road*. For example, if 99 percent of traffic on the road are 2 ton cars/trucks while the remaining 1 percent consists of 20 ton trucks, then the mean weight "W" is 2.2 tons. More specifically, [the equation] is not intended to be used to calculate a separate emission factor for each vehicle weight class. Instead, *only one emission factor should be calculated to represent the "fleet" average weight* of all vehicles traveling the road.[257]

Second, the Applicant assumed an empty truck weight for large haul trucks of five tons and a full truck weight equaling 30 tons.[258] This results in an average truck weight of 17.5 tons and means that these trucks are hauling 25 tons of material. An empty product truck weight of five tons, however, is not realistic – a five ton truck is not an appropriate size for hauling 25 tons of material. For most product-handling facilities, emission calculations are based on an empty truck weight of at least 15 tons. For example, the Taylorville Energy Project estimated paved road emissions on empty truck weights of 25 tons for hauling slag, 15 tons for hauling liquid sulfur and 15 tons for methanol deliveries.[259] The EPA, in developing AP-42 Section 13.2.1, identifies an average vehicle weight of 35 tons for heavy duty diesel trucks.[260] A 20-ton truck (empty)

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[256] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-4.

[257] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-4, *emphasis* added; http://www.epa.gov/ttnchie1/ap42/ch13/final/c13s0201.pdf.

[258] 1/10/2013 HECA Updated Emissions Data, "Fugitive Dust on Paved Road," p. 16 of 17, pdf 120.

[259] Taylorville Energy Center, Table C-21: Haul Road Potential Emission Calculations, p. C-68.

[260] EPA, Emission Factor Documentation for AP-42, Section 13.2.1, January 2011, p. 4-37; http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s0201.pdf.

hauling 25 tons of material has an average vehicle weight of 32.5 tons.[261] Correcting the average product truck weight from 17.5 tons to 32.5 tons (and for the moment ignoring the effect of the few operation and maintenance vehicles on the average on-site vehicle weight) will increase emissions by a factor of 1.88.[262] The District should obtain from the Applicant the vehicle count and empty and loaded vehicle weights for each of the vehicles that would operate on site (operation and maintenance vehicles, haul trucks for coal, petcoke, limestone fluxant, fertilizer product, sulfur product, gasification solids, methanol, etc.) to determine a correct fleet-average weight for purposes of estimating fugitive dust emissions from paved roads. Because the PDOC permits delivery of coal via both rail and truck[263] and contains no compliance conditions other than daily throughput at truck unloading and transfer system, the District should base its PTE calculations for fugitive dust from paved roads on a worst-case scenario, *i.e.*, deliveries of all fuels via truck.

Summary

The PDOC must be revised to include fugitive dust emissions from on-site paved roads in the PTE and ambient air quality modeling taking into account the above discussed errors and incorporate appropriate silt loading and vehicle weight modifications. Emission factors determined for purposes of modeling short-term PM10 and PM2.5 emissions may not include the rainfall correction factor.

Further, the PDOC does not currently provide a description of any of the onsite roads or any requirement that roads at the Project site would be paved. The PDOC should include such a detailed description of all roads on site and require that they are paved. If there are any unpaved roads on site, the emission estimates must be calculated based on EPA's guidance for unpaved roads.[264] The PDOC's compliance conditions addressing fugitive dust from paved and unpaved roads must be amended to ensure compliance with the estimated emissions, *e.g.*, requiring measurement of silt loading as required in permits for other gasification facilities.

b) Wind Erosion

The PDOC fails to account for particulate matter emissions due to wind-blown dust from roadways, parking areas, and access areas at the facility site in its PTE

[261] (20 tons + 45 tons)/2 = 32.5 tons.

[262] $(32.5)^{1.02}/(17.5)^{1.02} = 1.88$.

[263] PDOC, p. 7.

[264] EPA, AP-42, Section 13.2.2, Unpaved Roads, November 2006; http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0202.pdf.

calculations. These emissions can be calculated with EPA's AP-42, Section 13.2.5, *Industrial Wind Erosion*.[265]

V.C Lack of Enforceable Compliance Conditions

In addition to the above discussed problems with the PDOC's enforceability, there are several other areas that lack enforceable compliance conditions to ensure compliance with the PTE and emission limits as determined by the District.

V.C.1 Lack of Fuel/Feedstock Specifications

Many of the emission estimates relied upon by the PDOC to determine the PTE for the HECA Project are based on assumptions about the origin of the coal and petcoke as well as the ratio of these fuels in the feedstock blend that would be gasified at the facility. For example, the emission factors for NOx, CO, VOC, particulate matter, and SO_2 used to determine emissions from the power block are based on the highest emission factors for each pollutant from six operating scenarios (at various ambient temperatures and on peak/off peak) using a feedstock blend with 75% calorific input from "Lee Ranch Coal" and 25% calorific input of "Carson High Sulfur Coke." These emission factors were provided by MHI specifically for the MHI 501GAC CTG operating on this feedstock blend[266] and were presumably determined at MHI's Nakoso facility. Similarly, the Applicant's calculations of mercury emissions rely on the assumption that the Project would gasify coal from Peabody's El Segundo mine with a mercury content of 0.13 parts per million by weight ("ppmw").[267] Emission factors vary with the specific characteristics of the fuel and the feedstock blend. Yet, the PDOC entirely omits any discussion of or includes compliance conditions for fuel specifications or the 75% coal/25% petcoke feedstock blend; it also does not supply a vendor guarantee for the assumed emission factors when firing a different feedstock blend or using different fuels.

The Applicant insists that it requires permission to gasify a range of feedstock blend in order to

> … maintain sufficient fuel diversity and maximize the number of potential fuel suppliers; this is necessary to minimize fuel costs and avoid curtailment caused by short-term disruptions in fuel supply that can occur in the absence of sufficient flexibility.

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[265] http://www.epa.gov/ttnchie1/ap42/ch13/final/c13s0205.pdf.

[266] 1/10/2013 HECA Updated Emissions Data, "Power Block – Emissions Summary" and "HRSG and Coal Dryer,"p. 5 of 32, pdf 38.

[267] HECA Response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Furthermore, HECA's specific Cooperative Agreement and Section 48A tax credits require that HECA use coal for at least 75 percent of the energy input for operations for the first 2 and 5 years, respectively, under each agreement. Accordingly, the Applicant would be willing to consider a target of 75 percent coal for the HECA Project's gasification feedstock (heat input basis), provided this is computed on an annual averaging basis, and there is sufficient margin to allow the HECA Project to run above the average during the first 5 years of operations to ensure meeting the minimum regulatory requirements.[268]

The Applicant also indicates that it is more likely that the HECA Project would gasify coal from Peabody's El Segundo mine rather than coal from the Lee Ranch mine, which was used to run the gasification test by MHI.[269] Coal from the Lee Ranch mine and El Segundo mine differ substantially in their composition with respect to calorific value, moisture content, ash content, sulfur content, trace element constituents, etc., as shown in the inset table below, and emission rates will vary with the coal composition. The same is true for petcoke from different suppliers.

Table 2: Coal Composition from Different Suppliers

	Lee Ranch mine*	El Segundo mine**
Moisture (as received) %	14.8	18.1
Ash (dry) %	21.3	17.9
Volatile matter (dry) %	39.2	40.8
Fixed carbon (dry) %	39.5	41.3
Btu content (dry)	10,860	11,209
Sulfur (dry) %	1.09	1.29
Sulfur lb SO_2/MMBtu	2.01	2.30
Mercury (dry whole coal) ppm	0.09	0.13

* Data are excerpted from Lee Ranch Coal, 2009 through 2013 Typical Analysis, May 11, 2009, provided by HECA in response to Sierra Club Data Request No. 38, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

** With the exception of mercury content in coal, data are excerpted from El Segundo, 5-Year Plan Typical Analysis, February 16, 2009, provided by HECA in response to Sierra Club Data Request No. 17, August 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf;

[268] HECA Response to Sierra Club Data Request No. 143.c; February 2013, http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[269] HECA Response to Sierra Club Data Request No. 17a, August 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf; and HECA Response to CEC Data Request A206, January 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-01-16_Applicants_Responses_to_CEC_Data_Request_Set_Three_45-Day_Extension_TN-69172.pdf.

mercury content in coal from the El Segundo mine was provided by HECA in response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Because the PDOC requires continuous emission monitoring only for NOx and CO[270] and determines compliance with emission limits for SOx, PM10, and VOCs by calculation[271] based on source testing once every 12 months,[272] exceedance of emission limits specified in the PDOC's compliance conditions for pollutants other than CO and NOx would not be detected during times other than the scheduled source test. For mercury emissions, an exceedance would never be detected as only one initial speciated source test is required after commissioning.[273] The PDOC must be revised to either contain testing for fuel specifications and a specific fuel blend or contain enforceable compliance conditions for all pollutants, that would ensure that emissions from the power block would not exceed specified emission limits when firing different coals or feedstock blends.

V.C.2 Lack of Operating Conditions for CO_2 Vent during Mature Operation

The PDOC calculates the PTE criteria pollutant emissions from the CO_2 vent assuming a cumulative maximum duration of venting episodes of 504 hours/year for early operations, which are expected to last approximately two years, and implements this assumption in a compliance condition.[274] During mature operations, significantly fewer venting episodes are expected for a total 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity).[275] The District should consider establishing compliance conditions for mature operations of the Project which incorporate fewer hours of permissible venting per year. Any such revision must ensure that HECA may not generate ERCs attributed to the emission reductions.

V.C.3 Compliance Conditions for Cooling Tower Are Not Enforceable

The PDOC establishes BACT for PM10 emissions from the cooling towers serving the gasification block and process unit (S-7616-27-0), the air separation unit (S-7616-28-0), and the power block (S-7616-29-0) as cellular type drift eliminators with a

[270] PDOC, Appx. A, Condition 64, p. A-61.

[271] PDOC, Appx. A, Condition 23, pp. A-55-A56.

[272] PDOC, Appx. A, Condition 54, pp. A-60.

[273] PDOC, Appx. A, Condition 53, p. A-59.

[274] PDOC, Appx. A, p. A-43.

[275] PDOC, Appx. I, pp. 7-8.

drift rate of 0.0005%.[276] The PDOC requires demonstration of compliance with the PM10 daily emission limits for the three cooling towers by multiplying the circulating water recirculation rate as determined by a non-resettable flow meter times the total dissolved solids ("TDS") concentration in the circulating water as determined by a quarterly cooling water sample analysis times the manufacturer's design drift rate for the drift eliminators.[277]

The performance of drift eliminators may change over time or with operating conditions. Yet, the PDOC contains no condition to demonstrate that the specified drift efficiency of 0.0005%, which is part of the above calculation for compliance demonstration, is continually met. Therefore, the PM10 emission limits are not enforceable. To demonstrate compliance with the PM10 emission limits – and limit emissions to those that were included in the air dispersion modeling – a condition must be imposed to assure that the specified drift efficiency of 0.0005% is continually met. This is normally achieved by requiring annual performance tests performed by a Cooling Technology Institute-licensed drift testing firm to assure compliance with the specification.

Further, Sierra Club recommends installing conductivity meters to quickly identify problems and keeping a log of all parameters including the calculated emission rate in lb/day to monitor trends and spot deterioration in performance.

V.C.4 *Lack of Enforceable Permit Condition for Nitric Acid Unit*

The PDOC calculates the PTE (or SPPE2) for NOx emissions from the nitric acid unit (S-7616-35-0) at 33,617 lb/year assuming the plant operates 8,052 hrs/year and includes a permit condition that establishes an annual emission limit for NOx.[278] This permit condition is not enforceable as there is no limit or monitoring proposed for the annual hours of operation of the nitric acid unit. Further, the PDOC calculates the PTE for NH_3 emissions from the nitric acid unit at 4,026 lb/year but fails to include any condition enforcing this emission estimate as a permit condition. Therefore the PTE for NOx and NH_3 emissions from the nitric acid unit are not enforceable. The PDOC must contain proper permit limits and monitoring and recordkeeping provisions to ensure compliance with both PTE estimates.

V.C.5 Lack of Enforceable PM2.5 Emission Limits

The PDOC calculates potential to emit for PM2.5 in Section VIII but fails entirely to incorporate enforceable compliance conditions for any of the Project's emissions

[276] PDOC, Appx. C, p. C-20.

[277] PDOC, Appx. C, Conditions 13 through 19 for S-7616-27-0, S-7616-28-0, and S-7616-29-0.

[278] PDOC, p. 89, and Appx. A.

units. Therefore, the facility's calculated PTE for PM2.5 is not enforceable and fails to guarantee that a) the Project's PM2.5 emissions would remain under the major source threshold, b) sufficient offsets are provided, and c) the conclusions of the AAQI/HRA analysis are correct. The PDOC must incorporate determination of compliance conditions to enforce the PM2.5 PTE determined in Section VIII.

V.C.6 Inadequate Reporting Conditions

Rather than only requiring that the Applicant keep records for inspection upon request by the District, Sierra Club recommends that the PDOC incorporate conditions requiring annual reporting to the District for all units that are required to keep records of emission limits (at a minimum when exceedances are recorded). The District must keep this information in its records and make it available to the public for review and to ensure compliance with permit conditions. Public participation and enforcement is a fundamental part of the Clean Air Act.[279] The Clean Air Act provides for civil penalties as a remedy available for enforcement by citizen plaintiffs when the agency has failed to take action.[280]

VI. THE PDOC FAILS TO REQUIRE BEST AVAILABLE CONTROL TECHNOLOGY AND LOWEST ACHIEVABLE EMISSION RATE

The federal Clean Air Act requires that a permit issued to a major new source of air pollution include emission limits that reflect the installation of BACT for each regulated air pollutant; in a nonattainment area, the Act requires emission limits that reflect installation of LAER for each regulated pollutant.[281] Federal regulations for permitting new facilities require BACT for new sources in attainment areas, and LAER – a generally more stringent level – for new sources in nonattainment areas. In the federal regulations, LAER is defined as:

> Lowest achievable emission rate (LAER) means, for any source, the more stringent rate of emissions based on the following:
>
> (A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

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[279] For example, *Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986) (Congress enacted § 304 specifically to encourage "citizen participation in the enforcement of standards and regulations established under this Act," S. Rep. No. 91-1196, p. 36 (1970), and intended the section "to afford ... citizens ... very broad opportunities to participate in the effort to prevent and abate air pollution.").

[280] 42 U.S.C. § 7604.

[281] 42 U.S.C. §§ 7471, 7475(a)(2), 7479(3), 7501; 7503(a)(2); 40 C.F.R. 51.21(j)(2),40 CFR 51.165(a)(1)(xiii).

> (B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.[282]

Under the federal regulations incorporated into District Rule 2401, BACT is defined as:

> Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.[283]

LAER thus differs from BACT in that there is no consideration of economic, energy or environmental factors and the cost considerations are extremely limited.[284] Cost can only be considered to the degree that the costs are so prohibitive that the source could not be built.[285] "If some other plant in the same (or comparable) industry uses that control technology, then such use constitutes evidence that the cost to the industry of that control is not prohibitive."[286]

The District implements BACT and LAER requirements in SJVAPCD Rules 2410 and 2201. Under California state law and Rule 2201, the District is required to apply "BACT" for new sources under essentially the same requirements as federal LAER.[287] As the District explains in the PDOC, the District's BACT definition does not allow a

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[282] 40 C.F.R. 51.165(a)(1)(xiii).

[283] Rule 2401, 40 C.F.R. 52.21(b)(12).

[284] NSR Manual p. G.3.

[285] *Id*.

[286] *Id*. at p. G.4.

[287] *See*, for example, SJVAPCD, Reasonably Available Control Technology (RACT), Demonstration for Ozone State Implementation Plans (SIP), April 16, 2009; http://www.valleyair.org/Air_Quality_Plans/docs/RACTSIP-2009.pdf.

consideration of costs for control techniques that have been achieved in practice."[288] The District's Rule 2201 definition of BACT requires:

> 3.10 Best Available Control Technology (BACT): is the most stringent emission limitation or control technique of the following:
>
> 3.10.1 Achieved in practice for such category and class of source;
>
> 3.10.2 Contained in any State Implementation Plan approved by the Environmental Protection Agency for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or
>
> 3.10.3 Contained in an applicable federal New Source Performance Standard; or
>
> 3.10.4 Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source.

The District's BACT requirement in Rule 2201 is thus more stringent than the BACT requirements in Rule 2410.[289] A permit cannot issue without proper BACT and LAER emission limits.[290] As discussed in the following, the PDOC's BACT analyses are flawed.

VI.A BACT and LAER Require a Thorough and Well-Documented Analysis

The following section presents the well-established requirements of the BACT analysis, most of which are applicable to the LAER analysis. Applicants must select LAER technology in a similar manner as BACT, as described above, except that there is no consideration of economic, energy, or environmental factors and cost considerations are minimal. BACT and LAER require a case-by-case analysis.[291]

By using the terms "maximum" and "achievable," the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining

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[288] PDOC, p. 143.

[289] *Id*.

[290] 42 U.S.C. §§ 7475(a)(4); 7503(a)(2); *see also Alaska Dep't of Envtl Conservation v. EPA,* 540 U.S. 461 (2004) (hereinafter "*Alaska DEC*") (upholding EPA's authority to block a PSD permit where the state permitting authority's BACT determination was unreasonable).

[291] 42 U.S.C. § 7479(3); 7503(a)(2); NSR Manual, pp. B.5, G.1-4.

BACT.[292] Pursuant to those requirements, "the most stringent technology is BACT" unless the applicant or Agency can show that such technology is not feasible or should be rejected due to specific collateral impact concerns.[293] The collateral impacts exception is a limited one, designed only to act as a "safety valve" in the event that "unusual circumstances specific to the facility make it appropriate to use less than the most effective technology."[294] If the Agency proposes permit limits that are less stringent than those for recently permitted similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected.[295] The need to aim for the lowest limits achievable as part of a BACT analysis was recently emphasized by the EAB, which stated in reversing a permit issuance:

> If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.[296]

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.[297] A proper BACT limit must account for both general improvements within the pollution control technology industry and the specific applications of advanced technology to individual sources, ensuring that limits are increasingly more stringent. BACT may not be based solely on prior permits, or even emission rates that other plants have achieved, but must be calculated based on what available control options and technologies can achieve for the

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[292] *Alaska DEC*, 540 U.S. at 485-86

[293] *Alaska Dep't of Envtl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002).

[294] *In re Kawaihae Cogeneration Project*, PSD Appeal Nos. 96-6, 96-10, 96-11, 96-14, 96-16, 7 E.A.D. 107, 117 (E.A.B. Apr. 28, 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific *local* impacts); *In re Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824, 827 (Adm'r 1989); NSR Manual at B.29.

[295] *In re Indeck-Elwood, LLC*, PSD Appeal 03-04, 13 E.A.D., slip op. at 77, 79-81 (E.A.B. Sept. 27, 2006); *In re Knauf Fiber Glass, GMBH*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 131-32 (E.A.B. Feb. 4, 1999).

[296] *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 16 (EAB 2009) (hereinafter "*In re NMU*"); see also *Utah Chapter of Sierra Club*, 226 P.3d at 734-35 (remanding permit where there "was evidence that a lower overall emission limitation was achievable").

[297] NSR Manual, p. B.12 ("[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control"); pp. B.5 ("[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams…"); and B.16 ("[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.")

project at issue and set standards accordingly.[298] For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.[299]

The BACT review "is one of the most critical elements of the PSD permitting process" because it determines the amount of pollution that a source will be allowed to emit over its lifetime.[300] As such, the BACT analysis must be "well documented" and a decision to reject a particular control option or a lower emission limit "must be adequately explained and justified."[301] While the applicant has the duty to supply a BACT analysis and supporting information in its application, "the ultimate BACT decision is made by the permit-issuing authority."[302] Therefore, the District has an independent responsibility to review and verify HECA's BACT analyses and the information upon which those analyses are based to ensure that the limits in any permit reflect the maximum degree of reduction achievable for each regulated pollutant.[303]

Information to be considered in determining the performance level representing achievable limits includes manufacturer's data, engineering estimates, and the experience of other sources.[304] The Applicant and agency must survey not only the EPA's RACT/BACT/LAER Clearinghouse ("RBLC") and their own databases, but also many other sources, both domestic and foreign, including other agencies' determinations and (draft) permits, permit applications for other proposed plants, technology vendors, performance test reports, consultants, technical journal articles, etc.

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[298] An agency must choose the lowest limit "achievable." While a state agency may reject a lower limit based on data showing the project does not have "the ability to achieve [the limit] consistently," *In re Newmont*, PSD Appeal No. 05-04, 12 E.A.D. 429, 443 (E.A.B. Dec. 21, 2005), it may only do so based on a detailed record establishing an adequate rationale, *see id.* Moreover, actual testing data from other facilities is relevant to establishing what level of control is achievable given a certain technology. *Id*. at *30. The word "achievable" does not allow a state agency to only look at past performance at other facilities, but "mandates a forward-looking analysis of what the facility [under review] can achieve in the future." *Id*. at *32. Thus, the agency cannot reject the use of a certain technology based on the lack of testing data for that technology, where the record otherwise establishes that the technology is appropriate as an engineering matter. NSR Manual, at B.5.

[299] NSR Manual at B.5.

[300] *In re Mississippi Lime*, 15 E.A.D. --, slip op. at 17; *In re Knauf,* 8 E.A.D. at 123-24.

[301] *In re Mississippi Lime*, slip op. at 17; *In re Knauf*. at 131

[302] *In re: Genesee Power Station Ltd. Partnership,* 4 E.A.D. 832, 835 (EAB 1993)

[303] *See* 42 U.S.C. § 7479(3) ("permitting authority" makes BACT determination); 40 C.F.R. § 70.7(a)(5).

[304] NSR Manual, p. B.24.

VI.B BACT is Typically Evaluated Through a 5-Step, Top-Down Process

EPA established the top-down process described in the NSR Manual in order to ensure that a BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that BACT represent the maximum achievable reduction.[305] While an agency is not required to utilize the top-down process as laid out in the NSR Manual, where it purports to do so, the process must be applied in a "reasoned and justified manner."[306] As the U.S. Environmental Appeals Board ("EAB")[307] recently explained:

> The NSR Manual's "top-down" method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the "top," or most stringent alternative, that the analysis presumptively ends there and the top option selected — "unless" technical considerations lead to the conclusion that the top option is not "achievable" in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate.[308]

More specifically, the top-down BACT process consists of five steps that are discussed in detail in Section B of the NSR Manual.

1. Identify All Available Control Options

The first step in the BACT process is to identify "all potentially available control options."[309] The goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options," including LAER, is compiled.[310] As the EAB has emphasized, "available is used in its broadest sense under the first step and refers to control options with a 'practical *potential* for application to the emission unit under evaluation."[311] A control option is considered "available" if "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable

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[305] *Alaska Dept. of Envtl. Conservation v. EPA*, 540 U.S. 461, 485 (2004).

[306] *Alaska Dept. of Envtl. Conservation v. EPA*, 298 F.3d at 822.

[307] The EAB is EPA's supreme adjudicative body. *See* Changes to Regulations to Reflect the Role of the New Environmental Appeals Board in Agency Adjudications, 57 Fed. Reg. 5320 (Feb. 13, 1992). EAB decisions represent the position of the EPA Administrator with respect to the matters brought before it. *See Tenn. Valley Auth. v. EPA*, 278 F.3d 1184, 1198–99 (11th Cir. 2002) (finding EAB decision to be "final agency action").

[308] *In re NMU,* slip op. at 13.

[309] *In re Mississippi Lime,* slip op. at 11.

[310] *In re Knauf*, 8 E.A.D. at 130.

[311] *Id.* (*emphasis* in original).

reduction in emissions of regulated pollutants or will otherwise represent BACT."[312] The definition of BACT requires that the options considered include "application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."[313]

2. Eliminate Technically Infeasible Options.

Step two of the BACT process involves evaluating the technical feasibility of the available options and eliminating those that are not feasible.[314] Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology.[315] Feasibility is presumed if a technology has been used on the same or similar type of source in the past.[316] This step in the analysis has a purely technical focus and does not involve the consideration of economic or financial factors (including project financing). A demonstration of technical infeasibility should be clearly documented and must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.[317]

3. Rank Remaining Control Technologies by Control Effectiveness

The next step in BACT process is to rank the available and feasible control technologies for each pollutant in order of effectiveness.[318] That is, for each pollutant, the most effective control option is ranked first, and relatively less effective options follow with the least effective option ranked last. The evaluation should address control effectiveness (percent pollutant removed); expected emission rate (tons per year); expected emission reduction (tons per year); energy impacts (Btu, kWh); environmental impacts (other media and the emissions of toxic and hazardous air emissions); and economic impacts (total cost effectiveness, incremental cost effectiveness).[319]

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[312] *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm'r June 9, 1989).

[313] 42 U.S.C. § 7479(3).

[314] NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11.

[315] *Id.*; *In re Knauf,* 8 E.A.D. at 130.

[316] *Id.*

[317] NSR Manual, Table B-1.

[318] *In re Mississippi Lime*, slip op. at 12.

[319] NSR Manual, Table B-1.

4. Evaluate the Most Effective Controls and Document the Results

The fourth step in the BACT process is to evaluate the collateral economic, environmental and energy impacts of the various control technologies.[320] This step typically focuses on evaluating both the average and incremental cost-effectiveness of a pollution control option in terms of the dollars per ton of pollution emission reduced.[321] The point of this review is to either confirm the most stringent control technology as BACT, considering economic, environmental, or energy concerns, or to specifically justify the selection of a less stringent technology based on consideration of these factors.[322] This step is not relevant to a LAER analysis or an analysis under the SJAPCD's definition of BACT under Rule 2201.

5. Select BACT /LAER

The final step in the BACT process is to select the most effective control option remaining after Step 4. This option must represent the "maximum degree of reduction… that is achievable" after "taking into account energy, environmental, and economic impacts and other costs." BACT is an emissions limitation based on the most effective control option. The reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source and the technology must be specified in the permit.[323] "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)."

Under the District's BACT definition in Rule 2201, the final step is to choose the most stringent emission limitation of the four options in Section 3.1.

VI.C The PDOC's BACT Determinations Do Not Address All Pollutants Subject to Rule 2201 BACT Requirements

The District recognizes that pursuant to SJVAPCD Rule 2201, Section 4.1.1, BACT requirements are "triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis" for "any new emissions unit with a potential to emit exceeding

[320] NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12.

[321] *In re Mississippi Lime*, slip op. at 12.

[322] *Id.*

[323] NSR Manual, p. B.56.

2.0 pounds in any one day."[324] The PDOC, however, does not provide a table summarizing daily potential to emit (termed "daily post-project potential to emit" or "maximum daily PE2" by the District), which would enable the reviewer to quickly determine which emissions units exceed the 2.0 lbs/day BACT threshold for each pollutant. Instead, the PDOC in Section VIII, pp. 106-109, presents a one to two-paragraph discussion of BACT applicability under SJVAPCD Rule 2201 for each emissions unit based on the daily potential to emit for pollutants for each emissions unit presented earlier in the document in Section VII.C.2, pp. 68-92. The lack of a summary table not only needlessly requires the reviewer to thumb through 25 pages of text to determine whether the District's determinations of BACT applicability are consistent with its emission calculations, it obscures the fact that these BACT applicability determinations (and consequently its BACT analyses presented in Appendix C) are incomplete and do not comply with the requirements of SJVAPCD Rule 2201.

Affected pollutants under the rule include:

> those pollutants for which an Ambient Air Quality Standard has been established by the EPA or by the California Air Resources Board (ARB), and the precursors to such pollutants, and those pollutants regulated by the EPA under the Federal Clean Air Act or by the ARB under the Health and Safety Code including, but not limited to, VOC, NOx, SOx, PM2.5, PM10, CO, and those pollutants which the EPA, after due process, or the ARB or the APCO, after public hearing, determine may have a significant adverse effect on the environment, the public health, or the public welfare.[325]

Here, the PDOC presents "Daily Post-Project Potential to Emit" for only six pollutants/ precursors: NOx, SOx, PM10, CO, VOC, and NH_3.[326] The PDOC does not establish the daily potential to emit for all pollutants (or their precursors) for which an ambient air quality standard has been established or which were determined to potentially have a significant adverse effect on the environment, the public health, or the public welfare and therefore does not correctly determine applicability of BACT pursuant to SJVAPCD Rule 2201.

Table 3 below summarizes the daily potential to emit from the Project's emissions units exceeding the 2.0 lbs/day BACT applicability threshold for NOx, CO, VOC, SOx, PM10, PM2.5, NH_3, and H_2S compared to the BACT analyses for each emissions unit and pollutant performed by the District (shaded gray).

[324] PDOC, p. 106.

[325] SJVAPCD Rule 2201, Section 3.4.

Table 3: Daily potential to emit from HECA Project emissions units exceeding the 2.0 lbs/day BACT applicability threshold established in SJVAPCD Rule 2201 and BACT analyses performed by District

Emissions Unit	Emissions Unit ID	NOx[a] (lbs/day)	CO[a] (lbs/day)	VOC[a] (lbs/day)	SOx[a] (lbs/day)	PM10[a] (lbs/day)	PM2.5[b] (lbs/day)	NH_3[a] (lbs/day)	H_2S[c] (lbs/day)
Rail Car Unloading and Transfer System	S-7616-17-0					4.1	4.1		
Truck Unloading and Transfer System	S-7616-18-0					16.5	16.5		
Feedstock Storage, Blending, and Reclaim System	S-7616-19-0								
Feedstock Grinding, Crushing and Drying Operation	S-7616-20-0					5.2	5.2		
Gasification Solids Material Handling and Storage System	S-7616-22-0					3.6	3.6		
SRU Tail Gas Thermal Oxidizer	S-7616-23-0	535.7	449.1	12.3	51.9	17.0	17.0		
CO_2 Recovery and Vent System	S-7616-24-0		3,444.5	11,8916.4					**143.5**
Auxiliary Boiler	S-7616-25-0	30.7	189.1	20.4	14.6	25.6	25.6		
HRSG	S-7616-26-0	600.0	439.2	84.0	98.4	309.6	309.6	444.0	
Coal Dryer	S-7616-26-0	105.6	76.8	14.4	21.6	33.6	33.6	76.8	
Cooling Tower for Gasification Block and Process Units	S-7616-27-0					87.9	52.7		
Cooling Tower for Air Separation Unit	S-7616-28-0					8.1	4.9		
Cooling Tower for Power Block	S-7616-29-0					51.3	30.8		
Gasification Flare	S-7616-30-0	2,399.0	29,335.2	11.1	18.8	26.4	26.4		
SRU Flare	S-7616-31-0	59.3	70.2		441.6	2.6	2.6		
Rectisol Flare	S-7616-32-0	234.1	275.8	4.5	120.0	10.3	10.3		
Ammonia Synthesis Plant Startup Heater	S-7616-33-0	14.8	49.7	5.4	3.8	6.7	6.7		
Urea Unit with Urea Pastillation System	S-7616-34-0							314.4	
Nitric Acid Unit	S-7616-35-0	100.2						12.0	
Ammonium Nitrate Unit	S-7616-36-0					4.8	4.8		
Urea Storage and Handling Operation	S-7616-37-0					5.7	5.7		
Emergency Generator I	S-7616-38-0	77.3	402.0	46.4		10.8	10.8		
Emergency Generator II	S-7616-39-0	77.3	402.0	46.4		10.8	10.8		
Fire Water Pump	S-7616-40-0	44.1	76.5	4.1					
Fugitive Emissions from Gasification System (#1-#2 and #4-#10)	S-7616-21-0		24.4	90.5					**3.4**
Fugitive Emissions from SRU (#11-#12)	S-7616-23-0		**2.7**						**2.1**
Fugitive Emissions from Ammonia Synthesis Plant Startup Heater (#13-#21)	S-7616-33-0		5.9					**20.8**	**2.6**

Bolded values were not included in the PDOC's determination of daily potential to emit;
gray areas indicate BACT analyses included in the PDOC.

a Daily potential to emit for NOx, CO, VOC, SOx, PM10 and NH_3 from PDOC, Section VII.C.2, with the exception of fugitive emissions which were based on the 1/10/2013 HECA Updated Emissions Data and calculated as (maximum hourly emissions) × (24 hours/day) for each of the three process areas.

b With the exception of the cooling towers, daily potential to emit for PM2.5 was assumed the same as daily potential to emit for PM10. For the cooling towers, a fraction ratio of 0.6 PM2.5:PM10 was assumed consistent with the PDOC (Section VI, p. 33).

c Daily potential to emit for H_2S based on 1/10/2013 HECA Updated Emissions Data and calculated as (maximum hourly emissions) × (24 hours/day).

PM2.5 BACT

While the PDOC recognizes PM2.5 as a regulated pollutant for which ambient air quality standards have been established, it does not present a daily potential to emit for each emissions unit for this pollutant[327] and consequently does not determine BACT applicability for this pollutant for any emissions unit. As a result, the PDOC's BACT analyses do not provide separate BACT determinations for PM2.5 emissions, instead only determining BACT for PM10.[328] The Facility would have many units that exceed the 2 lb/day threshold as shown in Table 3 above. The District must establish BACT emission limits for PM2.5 emissions from each of these emissions units.

Ammonia BACT

While the PDOC determines the daily potential to emit for ammonia emissions from the HRSG and coal dryer vent, it argues that ammonia emissions are intrinsic to the operation of the SCR system and as such are not subject to BACT.[329] This is not acceptable as the District's rules do not provide for an exemption from BACT for control devices.

Further, the District fails to identify BACT applicability for ammonia emissions from the urea absorbers (314.4 lbs/day) and from the nitric acid unit (12.0 lbs/day), which by far exceed the 2.0 lbs/day threshold established in SJVAPCD Rule 2201.[330] The District must establish BACT emission limits for ammonia emissions from these emissions units.

Hydrogen Sulfide BACT

The PDOC does not present a daily potential to emit for the pollutant H_2S for which CARB established a 1-hour ambient air quality standard of 0.03 ppm in 1969.[331] Based on the emission calculations provided elsewhere, the H_2S emissions from the CO_2 vent can be calculated at 143.5 lbs/day and from fugitive equipment leaks assigned to the gasification system at 3.4 lbs/day, to the SRU at 2.2 lbs/day, and to the ammonia

[327] *See* PDOC, Section VII.C.2, pp. 70-93.

[328] PDOC, pp. 106-109 and 112-116 and Appx. B and C.

[329] PDOC, p. 106.

[330] *See* PDOC, p. 88.

[331] CARB, History of Hydrogen Sulfide Ambient Air Quality Standard, http://www.arb.ca.gov/research/aaqs/caaqs/h2s/h2s.htm.

synthesis plant startup heater at 2.6 lbs/day.[332] Consequently, the PDOC fails to determine BACT applicability and provide BACT analyses for H_2S emissions from the CO_2 vent and fugitive H_2S emissions from equipment leaks. The District must establish BACT emission limits hydrogen sulfide emissions from these emissions units.

Other Inadequate BACT Determinations

The PDOC recognizes that BACT pursuant to SJVAPCD Rule 2201 is triggered for SOx emissions from the sulfur recovery unit[333] and provides a BACT analysis in Appendix C. The PDOC calculates emissions of NOx, CO, VOC, and PM10 from the SRU tail gas thermal oxidizer in excess of the 2.0 lbs/day threshold but fails to determine that BACT is applicable and consequently fails to provide BACT analyses for these pollutants for the sulfur recovery unit.

Further, the PDOC calculates that PM10 emissions from the urea storage and handling unit at 5.7 lbs/day[334] but then erroneously claims that the daily potential to emit for PM10 from this emissions unit is less than 2.0 lbs/day.[335] Consequently, the PDOC fails to provide a BACT analysis for PM10 emissions from the urea storage and handling unit.

The PDOC's BACT applicability determination also fails to determine BACT for fugitive CO emissions from fugitive equipment leaks.

The PDOC must be revised to adequately demonstrate compliance with the BACT requirements of SJVAPCD Rule 2201 addressing the above discussed issues as well as other pollutant emissions that are covered under this rule (*e.g.,* sulfates).

VI.D The PDOC's BACT Determinations Pursuant to Rule 2201 BACT Requirements Are Inadequate

The PDOC recognizes that the Project is subject to the requirements of SJVAPCD Rule 2410, Prevention of Significant Deterioration, for NO_2, CO, PM, PM10, and GHG emissions.[336] The District finds that NOx, CO, PM and PM10 BACT requirements

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[332] Based on 1/10/2013 HECA Updated Emissions Data:
CO_2 vent: (5.98 lbs/hour H_2S) × (24 hours/day); fugitives gasification system (process areas #1, #2, #4-#10): (0.62 tons/year)/(356 days/year)×(2,000 lbs/ton); fugitives SRU (process areas #11 and #12): (0.39 tons/year)/(356 days/year)×(2,000 lbs/ton); fugitives ammonia synthesis startup heater (process areas #13-#21): (0.62 tons/year)/(356 days/year)×(2,000 lbs/ton).

[333] PDOC, p. 107.

[334] PDOC, p. 90.

[335] PDOC, p. 109.

[336] PDOC, p. 143.

pursuant to SJVAPCD Rule 2410 are satisfied by compliance with Rule 2201 requirements because the latter contains a more stringent definition of BACT. This finding and the District's later BACT analyses ignores the fact that under SJVAPCD Rule 2201, BACT requirements are triggered on an emissions unit-by-emissions unit basis whereas Rule 2410 requires BACT on a facility-wide basis and does not have a de minimus exemption for equipment emitting less than 2.0 lbs/day.

VI.E Common Problems with the PDOC's Approach to BACT Determinations

The District has never evaluated or permitted an IGCC plant prior to the HECA application. Yet, for most BACT determinations, the PDOC simply fits the unique HECA facility into the outdated existing off-the-shelf generic BACT determinations contained in the District's BACT Guidelines. The PDOC does not address or consider whether the novel nature of the HECA facility, relative to earlier facilities permitted by the District, necessitates facility-specific BACT determinations instead of simply adapting the closest generic BACT Guideline to HECA. (Worse yet, the PDOC incorporates several BACT Guidelines as the basis for its BACT determinations that were modeled after the Project at hand.[337])

For example, as discussed in detail in Comment VI.F below, air cooling is in common use at both combined-cycle power plants and refineries, and an IGCC plant includes elements of both of these facility types. Air cooling would serve the exact same function as the proposed wet cooling towers at HECA. Air cooling would not redefine the source even by the Applicants' narrow definition, *i.e.*, an IGCC facility intended to convert coal and petcoke to hydrogen-rich syngas for combustion and for manufacture of ammonia-based fertilizer products. The PDOC's BACT analysis does not mention air-cooling but instead only references a SJVAPCD generic cooling tower BACT determination last updated in June 2000. June 2000 pre-dates the online date of any of the operational air-cooled combined cycle plants in California.[338] The PDOC's failure to evaluate an air cooling alternative to the proposed wet cooling towers is a substantial deficiency in the document.

A similar failure occurs with the BACT determination for the HECA flares, as discussed in more detail in Comment VI.G. The PDOC references a SJVAPCD generic

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[337] For example, SJVAPCD, BACT Guidelines X.Y.Z for "Combustion Turbine Generator – Fired on Hydrogen-rich Syngas and Natural Gas, Uniform and Variable Load, With or Without Heat Recovery," dated November xx, 2010; "Coal/Coke Gasification CO_2 Recovery System," dated December xx, 2009; "Nitric Acid Unit," dated January xx, 2013; and "Ammonia Nitrate Unit," dated January xx, 2013.

[338] The first air-cooled combined cycle plant in California, Calpine's Sutter Power Plant, became operational in the summer of 2001. *See* California Energy Commission's webpage for the Sutter Power Plant "Key Dates;"http://www.energy.ca.gov/sitingcases/sutterpower/.

refinery flare BACT determination last updated in June 2006. No new refineries have been built in the SJVAPCD in decades and the last new refinery proposed, the Big West Refinery in Bakersfield, included a ground flare as opposed to the elevated flares proposed for the HECA Project.[339]

The use by SJVAPCD of outdated generic BACT determinations for the cooling process and flares at HECA is inconsistent with the technology-forcing nature of BACT. The SJVAPCD's definition of BACT is "the most stringent emissions limit… achieved in practice." What constitutes "achieved in practice" changes over time with technological advances. The reliance of the PDOC on the District's outdated generic BACT guidelines is inconsistent with the fundamental purpose of BACT.

VI.F BACT Determination for Cooling Towers Is Deficient

The proposed wet cooling towers (S-7616-27-0, S-7616-28-0, and S-7616-29-0) account for 83 percent of the water used at the HECA Project. The combined circulating water flow rate of the three HECA Project cooling towers is 303,500 gallons per minute ("gpm"); approximately 95,500 gpm of water will be circulated in the power block cooling tower; the air separation unit ("ASU") cooling tower circulation rate is approximately 45,000 gpm; and the process tower circulation rate is about 163,000 gpm.[340] Evaporation of the water in these cooling towers will result in particulate matter emissions. The three proposed wet cooling towers are the second largest source of PM10 and PM2.5 emissions at HECA after the combined cycle plant stacks, with projected emission rates of 26 tons/year PM10 and 16 tons/year PM2.5, contributing 29% and 20% of total Project emissions, respectively.[341] Air cooling would eliminate these PM10 and PM2.5 emissions and substantially reduce the Project's adverse impacts on air quality.

The PDOC's BACT analysis for cooling towers references SJVAPCD BACT Guideline 8.3.10, "Cooling Tower – Induced Draft, Evaporative Cooling."[342] This guideline identifies technologically feasible BACT for PM10 emissions from cooling towers as a cellular type drift eliminator. No other control alternatives are identified as achieved in practice or as an alternate.

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[339] EPA, Region 9, Revised Statement of Basis and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit – Big West of California LLC, November 29, 2007, p. 5. "The air pollution control equipment and techniques at the plant will consist of the following… A multipoint ground flare equipped with a flare gas recovery system."

[340] PDOC, p. 32.

[341] PDOC, p. 93.

[342] PDOC, Appendix C, p. C-20.

The obvious alternative to eliminate PM10 and PM2.5 emissions from cooling processes at HECA is to utilize air cooling. It is common practice to use air-cooled condensers on combined-cycle plants in California. For example, Colusa Generating Station, Gateway Generating Station, Otay Mesa Power Plant, and Sutter Power Plant are all operational combined-cycle plants in California that rely on air-cooled condenser technology.[343] Air-cooled condensers have zero emissions of PM10 and PM2.5. The fact that this cooling technology is in common use on California combined-cycle plants verifies that this cooling technology is achieved in practice as well as cost-feasible on combined-cycle plants in the state.

IGCC plant manufacturers also offer air cooling as a standard option for the entire plant. For example, for the last decade ConocoPhillips has advertised in public forums an air-cooled option to its standard IGCC plant design.[344] Air cooling was also evaluated by Powers Engineering as an alternative to cooling towers for the proposed Big West Refinery in Bakersfield in 2007.[345]

Thus, air cooling can be considered as "achieved in practice" and should be required as BACT without regard to costs, as required under California state law. However, even if cost were an issue, Sierra Club demonstrates below that air cooling would be cost-effective and should therefore be required as BACT.

VI.F.1 Cost of Cooling Towers and Associated Infrastructure at HECA

The cost of cooling tower capacity has been extensively studied in California. A comprehensive analysis of cooling tower retrofit costs at eleven coastal boiler plants in California, jointly contracted by the State Water Resources Control Board ("SWRCB") and the Ocean Protection Council ("OPC"), determined a retrofit cost range of $88 per kilowatt ("kW") to $151/kW for conventional cooling towers.[346] EPA indicates that the

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[343] CEC, Colusa Generating Station (CGS) Electrical Power Plant Project, Docket No. 06-AFC-09; http://energy.ca.gov/sitingcases/colusa/; CEC, Gateway Generating Station Power Project (formerly Gateway Contra Costa), Docket No. 00-AFC-01; http://energy.ca.gov/sitingcases/gateway/; PG&E Currents, Gateway Generating Station; http://www.pgecurrents.com/2012/08/07/climate-change-comes-to-the-power-industry/200x300_gateway-photo-3-2/; CEC, Otay Mesa Power Plant Licensing Case, Docket No. 99-AFC-05; http://energy.ca.gov/sitingcases/otaymesa/; CEC, Sutter Power Plant Project, Docket No. 97-AFC-02; http://energy.ca.gov/sitingcases/sutterpower/.

[344] R. Herbanek, T. Lynch – ConocoPhillips, E-Gas Applications for Sub-Bituminous Coal, presented at Gasification Technologies 2005, San Francisco, October 11, 2005.

[345] *See* Exhibit N, Bill Powers, Powers Engineering Comments on Big West CFP DEIR, March 27, 2007.

[346] TetraTech, California's Coastal Power Plants: Alternative Cooling System Analysis, February 2008. Eleven coastal steam boiler plants were included in the study. Nine of them fall within the $88/kW to $151/kW range. The cost of a conventional cooling tower retrofit at one plant not included in the range, Pittsburg Power Plant in the Bay Area, was an outlier at $193/kW. The reason for the higher cost at this plant is the relatively high expense of the circulating water piping due to the distance, approximately 4,000 feet, from the boilers to the cooling towers. One plant, Scattergood Power Plant adjacent to the Los

incremental cost of a retrofit cooling tower is approximately 20 percent greater than new construction.[347] Converting the range of California retrofit conventional cooling tower costs to new cooling tower construction gives a range of $70/kW to $121/kW. The median capital cost for a new conventional cooling tower, based on these data, would be approximately $95/kW.

One plant included in the SWRCB/OPC cooling tower retrofit study, the 803-MW Scattergood Power Plant adjacent to Los Angeles International Airport, would utilize a conservatively-designed plume-abated cooling tower, with an approach temperature of 12 F and a range of approximately 18 F. The collective flow rate for the three proposed retrofit cooling towers at Scattergood is 344,000 gpm.[348] The projected cost of the plume-abated cooling towers at Scattergood, in 2008 dollars, is $200/kW. Converting this retrofit cooling tower cost to a new construction cost would reduce the cost to $160/kW. Also, the proposed cooling tower flow rate at Scattergood, 344,000 gpm, is about 13 percent greater than the cooling tower flow rate at HECA of 303,500 gpm. Adjusting the Scattergood plume-abated cooling tower cost estimate to the new construction cost and a 13 percent reduction in flow rate gives an adjusted new plume-abated cooling tower cost for HECA of about $140/kW. This is equivalent to a plume-abated cooling tower capital cost at HECA of $112 million. The projected annualized cost of plume-abated cooling towers at HECA is provided in Table 4a below.

Angeles International Airport would utilize a conservatively-designed plume-abated cooling tower, with an approach temperature of 12 F and a range of approximately 18 F. The collective flow rate for the three proposed cooling towers at Scattergood is 344,000 gpm. The projected cost of the plume-abated cooling towers at Scattergood, in 2008 dollars, is $200/kW.

[347] EPA, Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule, April 2002, p. 2-33. "Additional Cooling Tower Retrofit Scaling Factor: 20 percent."

[348] TetraTech, California's Coastal Power Plants: Alternative Cooling System Analysis, February 2008, Chapter O.

Table 4a: Annualized cost of cooling system at HECA, plume-abated cooling towers

Element	Capital Cost ($MM)	Annualized Capital Cost ($MM/year)	O&M Cost ($MM/year)	Annual Cost or Delivery Cost ($MM/year)
Five groundwater extraction wells (7,500 AFY)	$3 million ($0.6 million/well)	$0.3 million	not calculated	$0.3 million/year
15-mile pipeline from wells to HECA	$8 million	$0.8 million/year	not calculated	$0.8 million/year
Raw water			NA	$3.4 million/year (7,500 AFY × $450)
Raw water OMP&R rate O&M, power, replacement			not calculated	
Raw water treatment plant	$14 million	$1.3 million/year	not calculated	$1.3 million/year
Power block cooling tower	$112 million (plume-abated)	$10.6 million/year	3.5 million/year	$14.1 million/year
Process cooling tower				
Air separation unit cooling tower				
ZLD processing plant	$22 million	$2.3 million/year	2.5 million/year	$4.8 million/year
Total:				**$24.7 million/year**

Notes:

1) AFY = acre-foot per year; O&M = operation and maintenance; OMP&R = operation, maintenance, power, and replacement; ZLD = zero-liquid discharge.
2) All capital costs are assumed to be amortized over 20 years at 7% interest (capital recovery factor = 0.0944).
3) Groundwater well and pipeline cost based on: HDR, Inc., *2011 South Central Texas Regional Water Plan. Volume II – September 2010, Appendix A Cost Estimation Procedures South Central Texas Region*, Tables A-3 and A-10, p. A-4 and p. A-10.
4) Raw water cost: HECA, Revised HECA Application for Certification, June 2009, Appendix O (BVWSD contract with HECA).
5) Raw water treatment plant cost based on: CH2MHill, *Lebanon (OR) Water System Master Plan - Water Treatment Plant and Source Water Analysis*, May 2007, Exhibit 7-14, p. 35 Capital Cost Comparison of Selected WTP/Intake Alternatives, Initial Plant Capacity = 6 mgd, average capital cost ~$14 million.
6) TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter O, Scattergood Power Plant, Table O-4, p. O-3. 344,000 gpm circulating water flow rate.
7) Water Reuse Foundation, *Survey of High Recovery and Zero Liquid Discharge Technologies for Water Utilities*, 2008, Table 5.1, p. 44. Case 4, 1.0 mgd ZLD facility, 12,000 ppm TDS.

Table 4b provides the projected annualized cost of conventional cooling towers at HECA, which is approximately $76 million.

Table 4b: Annualized cost of cooling system at HECA, assuming conventional cooling towers

Element	Capital Cost ($MM)	Annualized Capital Cost ($MM/year)	O&M Cost ($/year)	Annual Cost or Delivery Cost ($/year)
Five groundwater extraction wells (7,500 AFY)	$3 million ($0.6 MM/well)	$0.3 million	not calculated	$0.3 million
15-mile pipeline from wells to HECA	$8 million	$0.8 million/year	not calculated	$0.8 million/year
Raw water			NA	$3.4 million/year (7,500 AFY × $450)
Raw water OMP&R rate (O&M, power, replacement)			not calculated	
Raw water treatment plant	$14 million	$1.3 million/year		$1.3 million/year
Power block cooling tower	$76 million (conventional)	$7.2 million/year	3.5 million/year	$10.7 million/year
Process cooling tower				
Air separation unit cooling tower				
ZLD processing plant	$22 million	$2.3 million/year	2.5 million/year	$4.8 million/year
Total:				**$21.3 million/year**

As shown, the annual costs to HECA to utilize conventional cooling towers will be in the range of $21 to $25 million per year.

VI.F.2 Capital Cost of Air-Cooled Condenser(s) to Substitute for Cooling Towers at HECA

A comparison of the capital and operating costs of air-cooled condenser ("ACC") capacity to substitute for cooling towers was conducted by Powers Engineering for a proposed coal plant in Wisconsin.[349] A cooling tower consisting of 12 cells and a cooling water circulation rate of 250,650 gpm was specified by the developer for Weston Unit 4, a coal-fired plant in Wisconsin. Substituting an air-cooled condenser with a 35 F initial temperature difference ("ITD") for the cooling tower in the Weston Unit 4 application would require 66 cells and cost approximately $66 million in 2005 dollars. The total cooling tower flow rate at HECA is 303,500 gpm. Therefore the total number of ACC cells needed at HECA would be: (303,500 gpm)/(250,650 gpm) × 66 cells = 80 cells at $80 million in 2005 dollars. This translates to about $100 million in 2012 dollars.[350]

[349] Bill Powers, Powers Engineering, Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler, June 2005.

[350] Chemical Engineering, Economic Indicators, July 2012. Chemical Engineering Plant Cost Index ("CEPCI") in 2005 = 468.2; CEPCI in April 2012 = 596.0. Therefore cost increase from 2005 to 2012 would be: 596.0/468.2 = 1.27.

For a 35 F ITD ACC the air cooling heat rate penalty at design conditions is 2.8 percent relative to a conventional wet tower, and the annual average heat rate penalty is approximately 1.5 percent. At 20-year amortization at 7 percent interest, the annual cost of this air-cooled condenser capacity would be about $9.5 million. Assuming 250 horsepower ("hp") fans, the continuous fan energy cost at a wholesale electricity cost of $30 per Megawatt-hour ("MWh") and 37 percent annual capacity factor would be about $1.5 million/year.[351,352,353] The total annual cost of the ACC option would be in the range of $11 million/year without accounting for the 1.5% overall efficiency penalty.

The HECA combined cycle plant will generate a gross output of 431 MW. A 1.5% annual efficiency penalty would reduce gross output from 431 MW to about 424 MW, a reduction of 6.5 MW. The cost of the 1.5% annual efficiency penalty would be $0.6 million/year.[354] The power block appears to use about half of HECA's cooling capacity based on the description of the three cooling towers in the PDOC.[355] Assuming the 1.5% power block efficiency penalty imposed by the 35 F ITD air-cooled condenser is comparable to the efficiency penalty imposed on the cooling capacity servicing process units, an additional $0.6 million/year in efficiency penalty would apply to process cooling as well. It is important to note that fin-fan air coolers could serve the process cooling requirement, as described in Exhibit N to these comments.

VI.F.3 Air Cooling Should Be PM10/PM2.5 BACT for Cooling Processes at HECA

As explained above, under the District's definition of BACT, the District's BACT definition does not allow a consideration of costs for control techniques that have been achieved in practice." Since air cooling has been achieved in practice, costs cannot be considered. The Applicant's consultant nonetheless prepared a cost-effectiveness analysis. This cost-effectivenesss analysis should not be considered, as the District

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[351] DOE, Energy Information Administration, Today in Energy - 2012 Brief: Average wholesale electricity prices down compared to last year, January 9, 2013. Average Southern California wholesale electricity price in 2012, $30/MWh.

[352] CEC, Staff Paper – Thermal Efficiency of Gas-Fired Generation in California: 2012 Update, March 2013, Table 2, p. 5. Average capacity factor of California combined cycle fleet in 2012 = 36.8%.

[353] Assume wholesale energy cost of $0.03/kWh. 250 hp/cell × 80 cells = 20,000 hp (14,920 kW). Annual fan operating cost would be: $0.03/kWh × 14,920 kW × 8,760 hr/year × 0.37 (capacity factor) = $1.5 million/year.

[354] 431 MW × $30/MWh × 8,760 hr/year × 0.37 × 0.015 = $0.63 million/year.

[355] PDOC, p. 63.

acknowledges. Sierra Club nonetheless discusses the problems with the Applicants' cost analysis below.

The total estimated cost of the air cooling alternative to cooling towers at HECA is approximately $12 million/year. This is below the estimated $21 to $25 million/year "all-in" cost of cooling towers and associated water supply and wastewater disposal infrastructure at HECA. Use of air cooling at HECA would lower PM10 and PM2.5 emissions and not increase costs. For these reasons, the PDOC should have identified air cooling as BACT for cooling processes at HECA.

The BACT comparative cost-effectiveness calculation of air-cooling and wet cooling towers at HECA prepared by the Applicant's consultant, URS, includes only the cost of the wet cooling towers in the calculation of PM10 control cost effectiveness. As HECA acknowledges, the overwhelming majority of the water consumption at HECA, 83 to 85%, is associated with cooling tower evaporative losses and blowdown losses.[356] All components associated with water supply, including the groundwater wells, 15-mile water pipeline to HECA, raw water treatment, cooling towers, and zero liquid discharge system as well as the cost of offsets for particulate matter emissions must be included in the total wet cooling cost-effectiveness calculation to allow an apples-to-apples comparison with the air cooling option. When this is done, air cooling is a lower-cost alternative to cooling towers that eliminates cooling tower PM10 and PM2.5 emissions. The air cooling cost calculation carried-out by URS should be given no weight by the SJVAPCD, as it fails to include many substantial cost elements that are essential and integral to the proper functioning of the cooling towers.

Fluor Corporation conducted a water minimization study for the HECA Project power block cooling system in January 2008.[357] Fluor identified a total process makeup water requirement for HECA of 5,134 gpm, of which 4,983 gpm was associated with the cooling towers. Fluor identifies the cooling tower(s) as responsible for 97% of total plant makeup water consumption. [358]

The Fluor study is inadequately documented. There are three cooling towers proposed at the HECA Project, yet the Fluor study evaluates in detail only the impact on water use of substituting the largest of the cooling towers, the power block cooling

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[356] HECA Responses to Sierra Club Data Requests – Nos. 98 through 131, December 2012, p. 126-1; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[357] Fluor Corporation, HECA Water Minimization Study, prepared for Hydrogen Energy International LLC, Contract: A3RW, Revision 0, January 3, 2008 (Appendix X to Revised HECA Application to CEC, May 2009); http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/revised_afc/Volume_II/Appendix%20X.pdf.

[358] *Ibid*, p. 7.

tower, with air cooling or a combination wet-dry cooling system. For this reason, the study shows a relatively high residual water consumption rate even when the power block cooling tower is substituted by an air-cooled condenser.[359] Fluor did not evaluate substituting the other two cooling towers with an air-cooled alternative to largely eliminate the need for makeup water at the HECA Project.

Fluor provides insufficient information regarding the cooling tower and air-cooled condenser alternative to determine whether or not the capital cost delta of $37 million is reasonable. No design assumptions are provided for either the wet cooling tower or the air-cooled condenser.

The assumed annual efficiency penalty imposed by use of an air-cooled condenser in the Fluor study, 8.4 MW, is just under 2% for the HECA 431 MW (gross) combined cycle unit. This appears relatively accurate, based on the Weston Unit 4 wet versus dry cooling comparison in a cooler climate (Wisconsin), though no design information is provided for either the cooling tower or the air-cooled condenser to verify the annual efficiency penalty.

VI.F.1 Cooling Water with Lower TDS Content

Even if air cooling were rejected as BACT for the HECA Project's cooling demands, the PDOC's BACT analysis for the Project's three wet cooling towers is deficient because it fails to analyze the use of cooling water with substantially lower total dissolved solids ("TDS") content for the process and power block cooling towers. Reduced TDS content in the cooling water leads to proportionally lower PM10 and PM2.5. Pre-treating water to reduce the TDS content is clearly technically feasible and is required for the cooling water used in the cooling tower serving the ASU.[360] The Applicant has repeatedly expressed its unwillingness to subject water used for the other two cooling towers to the same treatment due to "significantly increased capital cost and parasitic energy consumption."[361] If the District concludes that wet cooling is BACT, the PDOC's BACT analysis for the wet cooling towers must include a cost-effectiveness analysis for treating cooling water for lower TDS content.

VI.G BACT Determination for Flares Is Deficient

The PDOC proposes three elevated flares for the HECA Project (S-7616-30-0, S-7616-31-0, and S-7616-32-0), primarily serving the gasification block, the sulfur

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[359] *Ibid*, Tables 1 and 2, p. 3.

[360] PDOC, p. 15.

[361] For example, HECA Responses to CEC Data Requests Nos. A1 through A123, August 2012, p. A1-3; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-08-22_Applicant_Response_to_CEC_Data_Request_no-A1_through_A123_TN-66876.pdf.

recovery unit ("SRU"), and the Rectisol unit, with a purported CO and VOC destruction efficiency of ≥99%.[362] The PDOC references SJVAPCD BACT Guideline 1.4.8, "Refinery Flare," as the basis for the HECA Project BACT determination for flares.[363] The generic SJVAPCD BACT Guideline 1.4.8 for refinery flares identifies "engineered" air- and steam-assisted elevated flares VOC BACT as "achieved in practice." The elevated flare technology is identified in the SJVAPCD refinery flare BACT guideline as having a VOC destruction efficiency of ≥98%. (No definition of "engineered flare" is provided in the SJVAPCD BACT guideline document.) Presumably the SJVAPCD would require substantial supporting test data before making a determination that any elevated flare exceeds the BACT-level achieved-in-practice elevated flare performance of ≥98% identified by the SJVAPCD for refinery flares. Yet, no such supporting flare test data has been provided by HECA or is referenced by the SJVAPCD in stating that the flare VOC and CO destruction efficiency of the elevated flares at the HECA Project will be 99%.

VI.G.1 BACT Is the Use of Enclosed Ground Flares

The PDOC does not identify enclosed ground flares as demonstrated in practice, even though enclosed ground flares have been in common industrial use for decades, including at the ExxonMobil Refinery in Torrance, California[364] and have been proposed for the Big West Refinery in Bakersfield.[365]

Exposure of elevated flares to wind significantly reduces their combustion efficiencies. In addition direct monitoring of an elevated flare is not as feasible as it is with a ground flare. This could be remedied by the use of an enclosed ground flare for the expected periodic events associated with gasifier startup. The Bay Area Air Quality Management District ("BAAQMD"), where five large petroleum refineries are located, identifies use of an enclosed ground flare as "Technologically Feasible/ Cost Effective" BACT for flare VOC emissions.[366] The BAAQMD also assigns an assumed VOC destruction efficiency of ≥98.5% to an enclosed ground refinery flare[367], higher than the assumed destruction efficiency of ≥98% assumed by the BAAQMD for all other flares.

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[362] PDOC, Appx. C, p. C-30.

[363] PDOC, Appx. C, p. C-21.

[364] HECA to Sierra Club Data Requests – Nos. 98 through 131, November 2012, p. 122-1.

[365] EPA, Region 9, Revised Statement of Basis and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit – Big West of California LLC, November 29, 2007, p. 5. "The air pollution control equipment and techniques at the plant will consist of the following … A multipoint ground flare equipped with a flare gas recovery system."

[366] Bay Area Air Quality Management District, Best Available Control Technology (BACT) Guideline 82.1, Flares - Refinery, June 30, 1995; http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

[367] *Ibid*.

This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds.

A single enclosed ground flare could readily accept maximum flare gas flow during the planned gasifier startups; the elevated flares proposed by HECA would also be necessary to handle higher flare gas volumes that could occur during major malfunctions or force majeure emergency events. Flares, either enclosed ground flares or elevated emergency flares, are relatively inexpensive pieces of equipment. The capital cost of an enclosed ground flare capable of handling 100 tons per hour of VOCs is approximately $4 to $5 million. An elevated flare capable of handling ten times this heat input under force majeure emergency conditions costs approximately $1.5 to $2 million. Flare BACT would be an enclosed ground flare to combust gasifier startup off-gases and elevated flares for all unplanned flaring events that exceed the capacity of the enclosed ground flare.

HECA asserts that there will be no malfunction flaring at HECA due to the high reliability of the gasifier technology that will be employed.[368] We discussed the improbability of this claim in Comment V.B.1. The assertion that there will be no malfunction flaring is also used as justification for not utilizing a flare gas recovery system, which is an integral component of the SJVAPCD definition of BACT for refinery flares.[369] Yet, the BACT analysis prepared by URS for the HECA Project lists many upset events that would result in flaring, stating: "*The gasification block will be provided with a relief system and associated gasification flare to safely dispose of gasifier streams during start-up, shut-down, and unplanned upsets or emergency events, syngas during AGR start-up, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures.*"[370] URS acknowledges a reasonable range of malfunction events that cause unplanned flaring, yet the PDOC does not attempt to quantify some level of malfunction flaring events. Both the URS flare BACT analysis and the PDOC are deficient for failure to quantify malfunction emissions.

It is for this reason – the likelihood of substantial periods of malfunction flaring at HECA and subsequent startup flaring following the malfunction shutdown(s) – that use of an enclosed ground flare, combined with use of elevated flares to handle major upsets caused by power outages (for example), should be flare BACT for the facility.

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[368] HECA Response to Sierra Club Data Request No. 62, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-12_Applicants_Supplemental_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67706.pdf.

[369] SJVAPCD BACT Guideline 1.4.8: "Flare shall be equipped with a flare gas recovery system for non-emergency releases…"

[370] Application, Appx. B, p. 55.

This is especially true given that HECA will not be installing flare gas recovery systems. The enclosed ground flare is a necessary component of the flare gas system in light of the failure by HECA to incorporate flare gas recovery system(s) in the plant design.

URS, the engineering consultant contracted by HECA to prepare permitting documentation, was part of a team of consultants that identified an enclosed ground flare as BACT for the proposed Pacific Mountain Energy Center ("PMEC") IGCC facility in Washington in 2006.[371] The estimated CO destruction efficiency of the enclosed ground flare was 99%.[372] The capacity of the enclosed ground flare for the gasification block at the Pacific Mountain Energy Center, at 3,730 MMBTU/hour, is essentially the same as the capacity of the proposed HECA gasification block flare at 4,000 MMBTU/hour.

Despite identifying an enclosed ground flare as BACT at PMEC, and acknowledging the superior CO destruction efficiency of enclosed ground flares relative to elevated flares, URS attempts to reject the enclosed ground flare as flare BACT for the HECA Project by stating: "*Compared to an elevated flare, an enclosed ground flare offers better CO destruction. However, enclosed ground flares pose potentially decreased dispersion of combustion gases and increased reliability concerns and have never been installed on any IGCC plants and so are considered unproven technology in this application with an associated risk*.[373] There are two operational coal-fired IGCC plants in the U.S., Wabash River IGCC and Polk Power Station IGCC, both of which were constructed almost 20 years ago.[374] The fact that there are only two such facilities puts the statement that "*(enclosed ground flares) have never been installed on any IGCC plants*" in context.

The advantages of enclosed ground flares are: reduced flame visibility, minimal heat and noise, ease of emissions sampling, smokeless combustion, and high destruction efficiencies attained by assuring the appropriate residence time.[375] Elevated flares are primarily elevated to reduce the impact of radiant heat and light during flaring events, not as a ground level impact air contaminant mitigation measure. Enclosed ground flares largely eliminate the effects on workers and nearby residents of radiant heat and light during flaring events. An enclosed ground flare has successfully operated at the ExxonMobil Refinery in Torrance, California for over two decades. The

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[371] *Ibid*, p. 121-1.

[372] Pacific Mountain Energy Center, EFSEC Application 2006-01, Appendix B Air Quality – B.1 BACT Analysis, Enclosed Ground Flare Emission Rates, Geomatrix Consultants, March 30, 2007.

[373] Application, p. 55.

[374] www.clean-energy.us webpage "About IGCC Power": http://www.clean-energy.us/facts/igcc.htm#projects.

[375] Flare Industries, Inc., General Description - Enclosed Ground Flares; http://www.flareindustries.com/products/thermal-oxidizers-enclosed-flares/files/10-enclosed-ground-flares.pdf

Sierra Club requested, and URS declined, to provide the safety and performance history of the Torrance Refinery enclosed ground flare.[376] This reality undermines the credibility of URS claims of concern regarding use of an enclosed ground flare at the HECA Project.

An operational challenge for elevated flares during periodic flaring of relatively small volumes of process upset gases is susceptibility to poorer performance in crosswinds. The annual average wind speed at the Bakersfield Airport near Buttonwillow at 10 meter height is 6.4 miles per hour ("mph").[377] The height of the HECA Project flares will be at least 250 feet (~80 meters).[378] Average wind speed will be substantially higher at the 80 meter elevation than at the 10 meter elevation. Test data collected on elevated flares by EPA to establish a destruction efficiency of 98% for elevated flares were all gathered at crosswind speeds of 5 mph or less.[379]

Wind can significantly reduce flare efficiency. Even at low wind speeds (below 3.5 meter/second or 7.7 mph), flare efficiency can be as low as 70%, with even more significant decreases in efficiency at higher wind speeds.[380]

A leading flare manufacturer has highlighted the problems that can cause low flare efficiency and other flaring problems. John Zink co-authored an article published in *Hydrocarbon Processing* on refinery flares, which states:

> The problem. To the casual observer, it may seem relatively easy to minimize and even eliminate routine flaring from refineries and petrochemical/chemical plants. It appears that these plants are unnecessarily wasting energy and generating pollution. The main challenge is that it can be uneconomical to

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[376] HECA Responses to Sierra Club Data Requests Nos. 98 through 131, December 2012, p. 122-1; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf: Data Request 122: "Please provide the safety history of Ground Flare 65F-8 at the ExxonMobil Torrance (CA) Refinery." Response: "As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request."

[377] California Climate Data Archive, Average Wind Speed – Bakersfield, California; http://www.calclim.dri.edu/ccda/comparative/avgwind.html.

[378] HECA Responses to Sierra Club Data Requests – Nos. 98 through 131, November 2012, p. 119-1; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[379] M. McDaniel – Engineering Science, Inc., Flare Efficiency Study, EPA-600/2-83-052, July 1983, p. 19; http://www.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf.

[380] Douglas M. Leahey, Katherine Preston and Mel Strosher, "Theoretical and Observational Assessment of Flare Efficiency," 51 J. Air & Waste Mgmt. 1610, 1616 (2001); http://www.endocrinedisruption.com/files/W15958Leahey2001.pdf.

recover the gases, either for use in the plant or to sell as energy, for a variety of reasons.

The flowrate and composition of the waste gases going to the flare are often highly variable. The unsteady flow … and variable composition … make it difficult to use the waste gases elsewhere in the plant where the energy demand is normally steady. The variable composition makes it difficult to sell, unless a purification system is added to produce a more consistent composition.

The waste gases may have a low heating value, which means that equipment such as burners must be properly designed for the low heating value. The waste gases may be off-spec product that is being flared because it cannot be sold and is not easily reprocessed to produce on-spec product. Off-spec flaring may occur for some time during startup until the product is within specification.

… There is growing concern that emissions of VOCs from flares may be much higher than previously thought. One possible reason is that wind effects can reduce flare destruction efficiency. The estimated emissions from flares are often based on measurements made with little or no wind. Accordingly, the emissions may be much higher under windy conditions.

… Another very challenging problem is that weather conditions, the waste-gas flowrate, and composition are highly variable and not generally controllable. For example, wind plays a very significant role in the performance of a flare.[381]

Another study cited in the *Hydrocarbon Processing* article identifies wind speed as a major impact on flare efficiency, cites wind tunnel flare efficiencies well under 90% in certain wind conditions, and references an earlier study that found average flare efficiency of only 70%as a result of crosswind effects.[382] These reduced efficiencies would drastically increase flaring emissions compared to emissions using an assumed 98% or 99% destruction efficiency.

VI.G.2 BACT Is the Use of a Flare Gas Recovery System

The PDOC determines that BACT for criteria pollutant emissions from the Project's three flares is a flare gas recovery system for non-emergency releases.[383] Yet elsewhere, the PDOC eliminates flare gas recovery system as a BACT control option for GHG emissions as technically infeasible stating "[g]iven the extremely infrequent nature of events producing flared gases available for recovery and the lack of a

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[381] J. Peterson, Flint Hills Resources, Corpus Christi, Texas, N. Tuttle, H. Cooper and C. Baukal, John Zink Co., LLC, Tulsa, Oklahoma, Minimize Facility Flaring, Flares Are Safety Devices that Prevent the Release of Unburned Gases to Atmosphere, June 2007 issue, pp. 111-115; http://www.johnzink.com/wp-content/uploads/flare_hydro_proc_june_20071.pdf.

[382] P.E.G. Gogolek, A.C.S. Hayden, Performance of Flare Flames in a Crosswind With Nitrogen Dilution, Journal of Canadian Petroleum Technology, August 2004, Volume 43, No. 8, p. 1.

[383] PDOC, Appx. C, pp. C-21-C-30.

reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged not to be feasible for the HECA facility."[384] The PDOC's compliance conditions for flares appear not to require installation of a flare gas recovery system.[385] As the District correctly determined in its BACT determination for criteria pollutants, a flare gas recovery system is feasible and must be required as BACT. Further, the PDOC's BACT determination for criteria pollutants is deficient in that it only addresses non-emergency releases. A proper BACT analysis must also address emergency releases from the flares, establish BACT emission limits and identify the respective control technology.

VI.H BACT Determination for Fugitive Equipment Leaks Is Deficient

As discussed above, fugitive emissions from equipment leaks would occur from 21 process streams throughout several areas throughout the HECA Project. The PDOC recognizes that BACT is required for fugitive emissions from equipment leaks and presents a BACT analysis in Appendix C.

The PDOC analysis assigns the HECA Project's 21 process streams to three emission units as follows:

S-7616-21 gasification system: process streams #1, 2, 4 through 10 (there is no #3);
S-7616-23 sulfur recovery unit: process stream #11 through 12; and
S-7616-33 ammonia startup heater: process streams 13 through 21.[386]

The PDOC's BACT analysis of fugitive equipment leaks from these aggregated process streams is deeply flawed.

First, rather than identifying all control technologies (Step 1 in a five-step top-down BACT analysis), the District identifies its own BACT Guidelines 4.12.1 for Chemical Plants Valves & Connectors and 4.12.2 for Chemical Plants Pump and Compressor Seals[387] only to find later by circular foregone conclusion that those very same BACT Guidelines constitute BACT for the HECA Project. This approach defies the clear requirements of a BACT analysis for purposes of the Clean Air Act, as discussed in Comment VI.E above. Again, the PDOC again relies only on information contained in the outdated SJVAPCD BACT Guidelines. A top-down BACT analysis must first identify all control technologies, which in this case includes leakless technology (*e.g.*, welded connectors, bellows valves, double mechanical seals with high pressure fluids

[384] PDOC, Appx. I, p. 39.

[385] PDOC, Appx. A, pp. A-78-A-100.

[386] PDOC, p. 37.

[387] PDOC, Appx. C, p. C-13.

on pumps, enclosed distance pieces on compressors with venting to a control device, etc.) The PDOC's BACT analysis fails to identify and analyze the feasibility of leakless technology for the HECA Project's equipment components.

Second, the PDOC in Appendix C presents a BACT analysis only for fugitive VOC emissions associated with the gasification system (S-7616-21) and the sulfur recovery unit (S-7616-23).[388] The title of this "top-down" BACT analysis fails to include the fugitive emissions associated with the process streams assigned to the ammonia startup heater.[389]

Third, the PDOC's BACT analysis finds (by circular reasoning) that BACT for VOC emissions from equipment leaks for the gasification system and the sulfur recovery unit is implementation of a leak detection and repair ("LDAR") program described as "a leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors and in excess of 500 ppmv above background for pump and compressor seals when measure [sic] per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455."[390] Review of the determination of compliance conditions in Appendix A shows that the District implements the above BACT determinations only for select process streams assigned to the gasification unit and the ammonia startup heater, but not the sulfur recovery unit, specifically for streams #1 (methanol), #5 (propylene), #7 (H_2S-laden methanol), #8 (CO_2-laden methanol), #9 (acid gas), and #10 (ammonia-laden gas) which are associated with the gasification system[391] and streams #13 through #21 which are associated with the ammonia synthesis unit. Thus, BACT as determined by the District, is not required for four of the Project's process streams, specifically it is not required for process stream #4 (shifted syngas) and #6 (sour water), which are associated with the gasification unit as well as #11 (sulfur) and #12 (TGU process gas), which are associated with the sulfur recovery unit. This partial application of BACT appears to stem from the Applicant's proposal to only apply LDAR to select process streams which were selected "because they had the largest uncontrolled emission estimates for methanol, propylene, H_2S, and ammonia."[392] The PDOC contains neither a discussion of this selective application of BACT nor does it provide a table summarizing emissions from the various process streams or a threshold below which it deemed BACT not necessary. This turns the BACT determination on its head because it implements the Applicant's predetermined preferences into conditions that instead should instead be based on BACT.

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[388] PDOC, Appx. C, pp. C-13-C-14.

[389] *Ibid*.

[390] PDOC, Appx. C, p. C-13.

[391] PDOC, Appx. A, Condition 9, p. A-22.

[392] PDOC, p. 37.

Finally, the PDOC's BACT analysis for fugitive emissions of GHGs is similarly flawed, again only identifying the District's BACT Guidelines as available technology and requiring BACT for select process streams only.[393]

VI.I The PDOC's BACT Determination for Greenhouse Gas Emissions for the Combined Cycle Power Generating System Is Deficient

The PDOC determines that BACT for GHG emissions from the HECA Project is 90% capture of pre-combustion CO_2 and sequestration and firing on hydrogen-rich fuel, energy-efficient turbine design, and firing on Public Utilities Commission ("PUC")-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages.[394] There are a number of problems with this BACT determination.

First, while the PDOC's GHG BACT analysis on its face is organized according to the above discussed five-step top-down process recommended by EPA, it does not actually follow the process. Step 1 of the BACT determination requires identification of all possible GHG emission controls. The PDOC identifies 90% capture of pre-combustion CO_2 and sequestration and firing on hydrogen-rich fuel as one of the possible control options. It should also identify and evaluate 100% capture of pre-combustion CO_2 and sequestration. Step 3 of a BACT determination requires that all available control technologies be ranked in descending order of control-effectiveness. The BACT determination does not assign any control efficiency to the any of the remaining control technologies. Further, the PDOC does not contain an enforceable permit condition verifying that the Project achieves 90% capture of pre-combustion CO_2 and sequestration.

VII. THE PDOC DOES NOT ADEQUATELY LIMIT THE FACILITY'S POTENTIAL TO EMIT HAZARDOUS AIR POLLUTANTS TO LESS THAN THE MAJOR SOURCE THRESHOLDS

The HECA Project would operate equipment that would have the potential to emit HAPs. Emission points include the HRSG stack, coal dryer stack, cooling towers, auxiliary boiler, ammonia plant startup heater, emergency generators and fire water pump, three flares, thermal oxidizer for the sulfur recovery unit, CO_2 vent, manufacturing complex, and fugitive and AGR unit vent in the gasification block; the exhaust stack serving the combined cycle combustion turbines ("CCCTs") and heat recovery steam generator ("HRSG") in the power block; the natural gas-fired burners in the coal milling and drying system; the gasifier coal bunker vents; the natural gas-fired

[393] PDOC, Appx. I, pp. 52-54.

[394] PDOC, Appx. I, pp. 23-24.

auxiliary boiler and startup heater; the diesel-fueled fire pump and emergency generator engines; and fugitive equipment leaks.[395]

The PDOC finds that the HECA Project is a minor source of HAPs, thus attempting to exempt this facility from maximum achievable control technology ("MACT") emission limitations. There are two types of minor sources: (1) a "genuine minor source" is one in which the potential to emit is below the major source threshold; (2) a "synthetic minor" source is one with potential emissions in excess of major source emission thresholds except that enforceable limitations on the source's potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. As shown below, the PDOC violates the fundamental principles regarding the creation of minor source permits, including synthetic minors, as the Project's actual potential to emit exceeds the major source thresholds for HAPs and the PDOC's compliance conditions do not ensure that emissions of HAPs from this facility will remain under major source thresholds.

Since this facility unquestionably has the potential to emit HAPs in excess of major source HAP emission thresholds and the PDOC does not have enforceable limitations on the potential to emit that would ensure emissions remain below these thresholds, the District may not authorize construction of the HECA facility without issuing a MACT/NESHAP determination.

VII.A Background on the Regulation of Hazardous Air Pollutants

The Clean Air Act reserves its strictest controls for hazardous air pollutants – air toxics posing serious health effects (often carcinogenic or neurotoxic) even in relatively small quantities.[396] The regulatory regime controlling hazardous air pollutants (contained in Section 112 of the Act) reflects the enormity of those pollutants' health effects.[397] It also reflects Congress' frustration with state and federal agencies' persistent failures to properly regulate air toxics; Congress described past regulatory efforts as a "record of false starts and failed opportunities."[398] As a consequence of those congressional concerns[399], Section 112 of the Clean Air Act bears three distinguishing

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[395] *See* PDOC, Appx. H.

[396] *See* 42 U.S.C. § 7412(b)(1)-(2) (listing hazardous pollutants and instructing U.S. EPA (hereafter referred to as "EPA") to add additional substances "reasonably anticipated to be carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic.").

[397] *See* S. Rep. No. 101-228, at 127 (1989), as reprinted in 1989 U.S.C.C.A.N. 3385, 3513-14 (noting that "ample margin of safety" might require "zero exposure to carcinogens, because any amount of exposure may cause a cancer").

[398] *Id*. at 3517.

[399] *Ibid.*

features: (1) extraordinarily strict limits, set by EPA; (2) direct, mandatory prohibitions that leave no room to avoid those limits; and, (3) express federal jurisdiction to address violations of those limits and prohibitions.[400]

The limits prescribed for hazardous air pollutants are those reflecting the "maximum achievable control technology" ("MACT"), defined as the "maximum degree of reduction in emissions…. that the Administrator [of the federal EPA] …. determines is achievable," considering costs, non-air quality health and environmental impacts, and energy requirements.[401] EPA sets MACT limits for categories of industrial facilities – often referred to as National Emission Standards for Hazardous Air Pollutants ("NESHAPs"); once set, they apply nation-wide to all major sources within those categories.[402] On March 28, 2013, after several challenges and revisions, EPA finalized nationwide MACT limits for new and existing coal and oil-fired electric generating units ("EGUs") in the so-called federal Mercury and Air Toxics ("MATS") rule.[403] (For a discussion of the Project's compliance with this rule, *see* Comment VII below.)

Unlike other similar limits in the Act, Congress added a "floor" to the MACT definition: MACT limits for new plants may "not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined [EPA]."[404] That floor is the heart of the MACT limit, resulting in standards that are substantially stricter than those the Act requires elsewhere.[405]

For example, the "best available control technology" limits applicable to other regulated pollutants allow individual sources to plead excessive costs, or infeasibility, and thereby secure relaxed standards.[406] The MACT floor, in contrast, applies

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[400] *See id*. at 3513 (noting Congress' intent to "entirely restructure the existing law, so that toxics might be adequately regulated by the Federal Government").

[401] 42 U.S.C. § 7412(d)(2).

[402] 42 U.S.C. § 7412(d)(1). *See, e.g.,* 74 Fed. Reg. 21,136, 21,140-41 (May 6, 2009) (setting standards for portland cement manufacturing facilities).

[403] EPA, National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric UtilitySteam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; http://www.gpo.gov/fdsys/pkg/FR-2013-04-24/pdf/2013-07859.pdf.

[404] 42 U.S.C. 7412(d)(3). MACT limits for existing sources have a slightly relaxed floor; they may not be less stringent than the "best performing 12 percent of the existing sources." 42 U.S.C. § 7412(d)(3)(A).

[405] *See* 59 Fed. Reg. 15,504, 15,564 (May 10, 1994) ("[T]he MACT floor is a fundamental requirement of the section 112(g) determination.").

[406] 42 U.S.C. § 7479(3).

regardless of cost, or even a particular plant's ability to meet the resulting standard.[407] And MACT limits are required for every hazardous air pollutant emitted by a facility.[408]

Mindful of agencies' reluctance to impose restrictions that might be "potentially very costly for some [regulated industries],"[409] Congress gave the federal EPA, rather than states, the authority and obligation to set nation-wide MACT standards for major sources of hazardous air pollutants.[410] Congress further pre-empted state authority to set "any emission standard or limitation which is less stringent than" the standards required by Section 112.[411]

Under Clean Air Act Section 112(g), "no person may construct or reconstruct any major source of hazardous air pollutants, unless [EPA] (or the State) determines that the [MACT] emission limitation … for new sources will be met."[412] Accordingly, the first step in the section 112 process is to determine whether a facility is a "major" or "minor" source of hazardous air pollutants. A major source of HAPs is defined as a stationary source or group of stationary sources located in a contiguous area and under common ownership and control which have the potential to emit at least 10 tons/year of any single HAP or at least 25 tons/year of all HAPs in total.[413]

VII.B The PDOC Does Not Adequately Restrict Emissions of Hazardous Air Pollutants to Ensure Synthetic Minor Source Status

The PDOC finds that the proposed compliance conditions would limit the facility's HAP emissions to less than the applicable major source HAP emission thresholds of 25 tons per year in the aggregate for total HAPs and less than 10 tons per year for any single HAP, thereby defining the HECA Project as a synthetic minor source.[414] However, the record does not support these claims.

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[407] *Natural Res. Def. Council v. E.P.A.*, 489 F.3d 1364, 1376 (D.C. Cir. 2007) ("[C]ost is not a factor that EPA may permissibly consider in setting the MACT floor."); *Cement Kiln Recycling Coal. v. E.P.A.*, 255 F.3d 855, 866 (D.C. Cir. 2001) (rejecting MACT floor based upon sources' ability to achieve limits).

[408] 42 U.S.C. § 7412(a)(6); *Nat. Lime Ass'n v. E.P.A.*, 233 F.3d 625, 633-34, 640 (D.C. Cir. 2000) (noting "clear statutory obligation to set emissions for each listed [hazardous air pollutant]" and suggesting that Section 112 "does not provide for exceptions from emissions standards based on *de minimis* principles where a floor exists").

[409] 1989 U.S.C.C.A.N. at 3517.

[410] 42 U.S.C. § 7412(e).

[411] 42 U.S.C. § 7416.

[412] 42 U.S.C. § 7412(g)(2)(B) (emphasis added). See 40 C.F.R. § 63.42(c).

[413] *See* 40 C.F.R. § 63.41; SJVAPCD Rule4002; SJVAPCD Rule 2550 (implementing 40 CFR part 63.40 through 63.44).

[414] PDOC, pp. 146-147, and 175-176.

The District does not appear to have conducted independent emission calculations for the proposed HECA Project; instead, it appears to have relied entirely on the Applicant's estimates of potential HAP emissions contained in the Application, Appendix F, to come to its conclusion that the facility is not a major source of HAPs.[415] The PDOC simply reproduces the Applicant's summary table for HAP emissions from the Project's various emissions units in Appendix H and concludes that the HECA Project is not a major source for HAPs pursuant to SJVAPCD Rule 4002 and therefore not subject to provisions of SJVAPCD Rule 2550,[416] which implements preconstruction review requirements of 40 CFR part 63.40 through 63.44.

The phrase "potential to emit" for HAPS is substantially similar to the PSD regulations.[417] Comment V discussed the requirements for calculating PTE in the PSD regulations. This discussion is equally applicable for HAP emissions.

As discussed before, the PDOC fails to provide the respective underlying calculations and assumptions to support the summary table in Appendix H and fails to incorporate the Applicant's substantially revised emission estimates for HAPs contained in the 1/10/2013 HECA Updated Emissions Data. Review of the latter shows that the underlying calculations are based on severely flawed and not adequately supported emission estimates, fail to calculate maximum (worst-case) HAP emissions, and fail to account for all pollutants and emission sources. The PDOC then compounds these errors by failing to reflect the emission calculations in enforceable permit limits. When properly estimated, potential emissions of HAPs from the proposed facility by far exceed the major source thresholds for both individual and total HAPs, making the proposed facility a major stationary source of HAPs and requiring MACT for all applicable sources.

VII.C Assumptions Are Not Adequately Supported

The District does not provide a discussion of HAP emission estimates in the PDOC and appears to have accepted the Applicant's emission estimates wholesale. Yet many of the Applicant's emission estimates for HAPs rely on emission factors from emission testing at other facilities, vendor-supplied information, or other studies that were not made available for public review. Thus, a considerable portion of the Applicant's emission estimates for HAPs are unsupported in the record. The following information, used by the Applicant to develop emission estimates for the facility, is not or not adequately supported:

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[415] PDOC, p. 146.

[416] PDOC, pp. 146-147, and 175-176.

[417] SJAPCD Rules 2520 & 2530.

- For example, as discussed before, the PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based the average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit and the fertilizer complex. These weight fractions are entirely unsupported.

- Uncontrolled coal dryer mercury emissions from volatilization estimated by MHI are not supported by a vendor guarantee.

- Assumed split between HRSG and coal dryer exhaust of 85%/15% is not supported.

- Mercury concentration in coal feed of 0.13 ppmw is not supported by feedstock analyses.

- Emission rates for the manufacturing complex are based on "reference plant information" with no support which plant the Applicant refers to nor a copy of source tests or any other supporting information.

- HAP emission factors for cooling towers using an average of analytical test results determined by Fruit Growers Laboratory are not supported by a copy of the test results or an explanation what type of facility was tested nor are specifications for the composition of the cooling tower water provided. No discussion is provided why the results of this test are assumed applicable to the HECA Project's cooling towers.

- CO_2 vent gas methanol concentrations are based on process licensor data with no vendor guarantee or other explanation.

In *In re Steel Dynamics, Inc.*, the Environmental Appeals Board remanded the permit back to the state agency after finding that the state agency's PTE evaluation was inadequate because the agency did not include explanations of the underlying basis for its calculations and the public record contained no documents supporting its conclusion.[418] Without this information, the Board determined that it was unable to determine whether or not the significance level for a given pollutant would be exceeded and, thus, whether BACT for lead should be installed at this facility. Moreover, the Board remanded the permit back to the state agency because it failed to consider detailed comments regarding an alternative calculation for potential to emit submitted by a commenter. The comments had articulated how the agency had underestimated the facility's emissions of lead and other hazardous air pollutants, erroneously failed to

[418] 9 E.A.D. 165, PSD Appeal Nos. 99-4 & 99-5, 2000 WL 833062 (June 22, 2000).

consider all potential sources of lead emissions, and finally presented its own calculated PTE after correcting for these deficiencies.

This PDOC is similar to the Steel Dynamics permit as the District's potential to emit evaluation for HAPs is inadequate, cursory, and not supported by documents in the record. Sierra Club addresses some of these deficiencies below.

VII.D The PDOC Underestimates the Facility's Potential to Emit for HAPs and Compliance Conditions Are Inadequate to Enforce the Synthetic Minor Source Status

As explained in the comments below, the emission calculations the PDOC relied upon to make its determination that the facility would be a minor source of HAP emissions are flawed and result in substantially underestimated emissions. Further, the PDOC's compliance conditions are not enforceable and identify the Project as a major source of HAP emissions because the emission limit for COS, a HAP, exceeds the 10 ton/year threshold triggering major source status for individual HAPs.

VII.D.1 Emissions from Flares Do Not Account for Unplanned Events and Rely on Inappropriate Emission Factors

Flares emit HAPs and TACs during both routine and non-routine operations from three sources: (1) pilot; (2) supplementary natural gas fuel; and (3) syngas and waste gases. The Applicant's estimates for HAP emissions from the three flares shows that only emissions from operation of the natural gas-fired pilots and during startup/shutdown are accounted for.[419] The Applicant did not discuss the use of HAP emission factors for flaring shifted and unshifted syngas, which may result in considerably higher emissions of HAPs than combustion of natural gas, nor did the Applicant make an attempt to estimate HAP emissions for unplanned malfunction (upset) events. As discussed in Comment VII.B above, emissions from unplanned events must be included in the potential to emit calculations.

Further, the Applicant' estimates emissions of HAPs from flares during pilot operation and gasifier startup/shutdown are based on emission factors from AP-42, Chapter 1.4, for natural gas-fired boilers.[420] This assumes the behavior of a flare from a combustion standpoint is similar to a natural gas fired boiler, which is not the case. A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. In contrast, a flare has no combustion chamber and highly variable gas

[419] *See* 1/10/2012 HECA Updated Emissions Data, "Gasification Flare – HAP Emissions Summary", p. 6 of 25, pdf 127; "SRU Flare – HAP Emissions Summary", p. 7 of 25, pdf 128; "Rectisol Flare – HAP Emissions Summary", p. 8 of 25, pdf 129.

[420] 1/10/2013 HECA Updated Emissions Data, footnote to tables "Gasification Flare," SRU Flare," and "Rectisol Flare," pp. 6-8 of 25, pdf 127-129.

flow and composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler. Further, the flares would combust syngas and waste gases which have a different composition than natural gas.

Sierra Club requested an explanation from the Applicant why it deemed emission factors from natural gas combustion in boilers representative for combustion of natural gas, syngas and waste gases in the Project's flares for both normal operating emissions from the pilot and during gasifier and Rectisol startup and shutdown. The Applicant responded that "Because the United States Environmental Protection Agency (U.S. EPA) has not published emissions factors for hazardous air pollutants (HAPs) from flares, the emission factors for HAPs from natural gas combustion in boilers have been used. During normal operation of the pilot, natural gas is being combusted—the same fuel represented in the emission factors. During start up and shut down of the gasifier and Rectisol flares, syngas is being burned, which is composed primarily of hydrogen. In this case, the applied emission factors are an overestimate of HAPs from flare combustion. Therefore, the emission factors used are appropriate and conservative."[421] This explanation is entirely unsatisfactory as it does not address the question why combustion in a flare may be assumed to be equivalent to combustion in a boiler nor does it adequately address the different composition vs. natural gas and syngas and waste gases. Neither the District nor the Applicant made any attempt to identify emission factors for flares. The District must identify appropriate worst-case HAP emission factors based on the composition of the various gas streams that may be routed to the flares.

VII.D.2 Emissions from the CO_2 Vent Are Underestimated, Emission Limits Are Incorrect, Establish the Project as a Major Source, and Are Not Adequately Enforced

The PDOC presents emission estimates for HAPs from the CO_2 vent for only two pollutants, H_2S and COS.[422] The Applicant revised its emission estimates for HAPs to include methanol emissions in the vent gas stream, which originates in the Rectisol unit. Further, the CO_2 vent stream may contain other HAPs including SO_2 which converts to SO_3 and sulfuric acid mist ("SAM"), a hazardous air pollutant. The PDOC must be revised to include all pollutants in its potential to emit for HAPs.

Further, for purposes of determining potential to emit for criteria pollutant, the PDOC estimates maximum annual VOC (methanol), H_2S, and COS emissions from the CO_2 vent assuming 21 days/year (equivalent to cumulative 504 hours/year) of venting

[421] HECA Response to Sierra Club Data Request No. 59, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

[422] PDOC, Appx. H.

at the full vent flow capacity (17,584 lb-mol/hour at 100%) and maximum concentrations of methanol, COS, and H_2S in the vent gas of 40 ppm, 10 ppm, and 10 ppm, respectively.[423] These assumptions result in emissions of 2.84 tons/year methanol[424], 1.51 tons/year H_2S, and 2.66 tons/year COS.[425] (As discussed in Comment V.B.3, the PDOC incorrectly calculates VOC emissions based on the molecular weight of methane (16 lb/lb-mol) instead of methanol (32 lb/lb-mol), thereby underestimating VOC (methanol) emissions by a factor of two.)

The PDOC does not provide detailed corresponding detailed emission calculations for HAP emission. However, review of the 1/10/2013 HECA Updated Emissions Data shows that for purposes of estimating HAP emission from the CO_2 vent, the Applicant relies on a far less conservative approach than described above for criteria pollutants, assuming an expected "average" vent flow at a reduced capacity of only 85%, and a lower "typical" long-term methanol concentration in the vent gas of 20 ppm.[426] This approach reduces the Applicant's emission estimates to 2.41 tons/year methanol, 1.28 tons/year of H_2S and 2.26 tons/year COS. Unless the PDOC includes enforceable permit conditions to ensure compliance with its estimates, which it does not, it must assume "maximum potential" emissions for all pollutants including HAPs.

By using this approach (and correctly assuming the molecular weight of methanol), the Applicant lowered total estimated facility methanol emissions – 9.83 tons/year – to just below the 10 tons/year threshold for emissions of individual HAPs that would trigger major source status. Revised emissions correcting for 100% vent flow capacity, concentrations in the vent stream of 40 ppm methanol, and the molecular weight of methanol and otherwise relying on the Applicant's assumptions can be estimated at 5.68 tons/year methanol.[427] When added to the fugitive methanol emissions from equipment leaks of 7.29 tons/year[428], this results in total annual facility methanol emissions of 13.09 tons/year, 30% above the major source threshold for individual HAPs.

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[423] PDOC, pp. 54, 81, and 93; *see* also, 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

[424] The PDOC calculates 5,672 lb/year on a methane basis and converts this estimate incorrectly to 2.34 tons/year instead of 2.84 tons/year.

[425] *See* PDOC, p. 81, for H_2S; COS = (504 hours/year)(17,584 lb-mol/hr)(60 lb/lb-mol COS)(10 ppm) = 5,324 lb/year = 2.66 tons/year.

[426] 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

[427] MeOH = (504 hours/year)(17,584 lb-mol/hr)(32 lb/lb-mol COS)(40 ppm) = 11,358 lb/year = 5.68 tons/year.

[428] 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

Further, the PDOC contains compliance conditions limiting emissions of COS from the CO_2 vent to 58.0 lbs/day, 14.62 tons/year, and 55 ppm.[429] These emission limits are inconsistent with the Applicant's assumptions for the concentration of this pollutant in the CO_2 vent stream of 10 ppm. Further, the emissions limit of 14.62 tons/year COS is inconsistent with the PDOC's determination that the HECA Project would not be a major stationary source of HAPs because COS is a HAP and the proposed emission limit is greater than the threshold of 10 tons/year for individual HAP emissions per District Rule 4002. Finally, revising the Applicant's emission estimates based on the District's permit condition for COS results in total HAP emissions from the facility of 30.94 tons/year, far in excess of the 25 tons/year major source threshold.[430] Thus, based on the PDOC's emission limits and conditions of compliance, the Project is a major source of HAPs.

VII.D.3 Fugitive Equipment Leaks Are Not Adequately Supported and Are Underestimated

As discussed before, the PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based an entirely unsupported average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit and the fertilizer complex.[431] As demonstrated above, even a minor variation in these assumptions could turn the Project in a major source of HAPs.

VII.D.4 Emissions from the HRSG and Coal Dryer Are Not Supported and Potential to Emit for HAPs Is Underestimated

As discussed in Comments II.A and IV.B.2, emission estimates for the HRSG and coal dryer are not adequately supported and rely on a number of assumptions that underestimate the facility's true potential to emit. The same problems were carried over into the Applicant's estimates of HAP emissions for these units. In addition, the HAP emission estimates for these units suffer from a number of other flaws.

The Applicant estimates HAP emissions from the HRSG and coal dryer based on emission factors from test data determined at the Wabash River PSI Energy's Wabash River Generating Station in Indiana and a 2002 report by the DOE's National Energy

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[429] PDOC, Appx. A, Compliance condition Nos. 8, 9, and 11 for CO_2 Recovery and Vent System (S-7616-24-0), pp. A-42 - A-43.

[430] 1/10/2013 HECA Updated Emissions Data, "Emissions Summary" dated December 20, 2012, p. 1 of 25, pdf 122: (19.12 tons/year total HAPs) – (2.80 tons/year COS) + (14.62 tons/year COS) = 30.94 tons/year total HAPs.

[431] 1/10/2013 HECA Updated Emissions Data, *see* note above table "Area Speciation" in "Fugitive Emissions – Gasification Unit," p. 19 of 25, pdf 140.

Technology Laboratory ("NETL")[432] which summarizes source test data from several gasification facilities.[433] Elsewhere, the Applicant claims that "All emission factors were based Wabash River test data … with the exception of ammonia, mercury, and sulfur/sulfuric acid…" for which it provided separate emission estimates.[434] Yet, comparison of the Applicant's emission estimates for the HRSG and coal dryer with the Wabash River test data and the 2002 DOE/NETL report shows that several other emission factors used by the Applicant to estimate HAP emissions are not consistent with than those in the referenced sources, as summarized in the inset table below.

Table 5: Discrepancies between emission factors relied upon by 2012 ATC/PSD Application and Wabash River test data and 2002 DOE/NETL Report

Pollutant	2002 DOE/NETL report (lb/10^{12} Btu)	2012 ATC/PSD Application (lb/10^{12} Btu)	Discrepancy (lb/10^{12} Btu)
Antimony	4	1.1	2.90
Benzene	4.4	2.4	2.00
Chromium	2.7	0.51	2.19
Cobalt	0.57	0.26	0.31
Lead	2.9	0.56	2.06
Manganese	3.1	1.0	2.1
Nickel	3.9	0.39	3.51
Selenium	2.9	0.56	2.34

The Applicant provides no discussion of these discrepancies. Further, the 2002 DOE/NETL Report provides emission factors for a number of HAPs that are not incorporated into the Applicant's emission estimates. These include emission factors for benzaldehyde, benzo(e)pyrene, benzo(g,h,i)perylene, 2-methylnaphthalene.

Further, many of the emission factors assumed by the Applicant as representative for the HECA Project are "average" emission factors determined from a limited number of source tests. As such, they do not adequately represent the facility's maximum potential to emit as required under the Clean Air Act and SJAPCD Rules.

VII.D.1 Compliance Conditions Are Not Enforceable

The PDOC includes several compliance conditions requiring HECA to demonstrate that the Project would be a minor source for HAPs. However, these

[432] DOE, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002, hereafter "2002 DOE/NETL Report"; http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/final%20env.pdf.

[433] *See* Note 2 to 1/10/2013 HECA Updated Emissions Data, "HRSG and Coal Dryer Stack – HAP Emissions Summary" dated December 20, 2012, p. 2 of 26, pdf 123.

[434] HECA Response to Sierra Club Data Request No. 38.t, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

conditions fall short of demonstrating compliance and fail to specify remedies in case it were discovered that the Project is not a minor source of HAPs.

First, the PDOC requires an initial speciated HAP and total VOC source test for the CO_2 recovery and vent system to determine the total HAPs emission rate, the single highest HAP emission rate and the VOC mass emission rate.[435] This condition does not address the variability of the gas stream that would be vented during the source test event. Vent gas composition will vary depending on the operating conditions of the facility at the time of venting, the fuel blend, the capacity at which the syngas scrubber, gas cooling, mercury removal, and acid gas removal units, etc., are functioning, and so forth. For example, under normal operating conditions, the gas stream from the sulfur recovery unit will be treated in the tail gas treating unit and then transported to the CO_2 vent system for custody transfer. However, in the event of any unscheduled tail gas treatment curtailment or operating problems, the sulfur recovery unit tail gas can be redirected into the CO_2 product stream.[436] A single speciated source test will therefore not capture the variability of HAP concentrations in the vent gas stream (*e.g.*, methanol concentrations in the vent stream will vary widely depending on the operating conditions in the Rectisol unit).

In addition, the same condition of compliance requires that HECA demonstrate initial compliance with the HAPs emission limits (25 tons/year all HAPs or 10 tons/year any single HAP). The PDOC fails to lay out a formula and specify emission rates from other emission sources to ensure that the Applicant's emission calculations include emissions from the entire stationary source instead of comparing only the CO_2 vent emissions to these emission limits.

The compliance conditions also require that HECA demonstrate ongoing compliance based on the vent stream composition of CO, VOC, H_2S, COS, and HAPs identified during the initial source test and determined using mass flow and VOC sampling during venting occurrences exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District. The PDOC does not provide a discussion of how the cutoff vent flow of 500,00 scf/day was determined during which the Applicant must measure the vent stream composition nor does it discuss why the vent gas composition cannot be monitored continuously.

[435] PDOC, Appx. A, Condition of Compliance No. 16, p. A-43.

[436] PDOC, Appx. C, p. C-16.

VII.E The PDOC Fails to Demonstrate Compliance with the National Emission Standards for Hazardous Air Pollutants for Electric Generating Units

On March 28, 2013, the EPA finalized the federal Mercury and Air Toxics ("MATS") rule for electric generating units ("EGUs"). The MATS rule establishes emission limits for new IGCCs at 0.07 lb/MWh (gross) on syngas and 0.09 lb/MWh (gross) on natural gas for particulate matter, 0.002 lb/MWh (gross) for hydrogen chloride, and 0.003 pounds per Gigawatt-hour ("lb/GWh") (gross) for mercury.

The PDOC does not provide a quantitative analysis demonstrating the HECA Project's compliance with the MATS rule and instead provides only the following brief summary discussing potential mercury emissions:

> In order to minimize potential mercury emissions, this project has incorporated mercury capture technology. Tests of petcoke sources show occasional trace levels of mercury in the elemental analyses. Western sub-bituminous coals typically contain trace levels of mercury as well. Mercury is removed downstream of the sour shift and low-temperature gas cooling (LTGC) units, and at the feedstock dryer using activated carbon. After mercury removal, the product syngas is treated in the acid gas removal (AGR) unit. These controls will reduce mercury emissions to a level that will comply with the new National Emission Standards for Hazardous Air Pollutants (NESHAP) for IGCC Electric Generating Units.[437]

This discussion is inadequate. First, the PDOC does not provide any documentation or emission estimates to back up its claim that HECA's mercury emissions would actually remain below the 0.03 lb/GWh (gross) emission limit established in the MATS rule nor does it identify the applicable MATS emission limit. Second, the PDOC does not require monitoring pursuant to MATS; thus its claim that HECA's mercury emissions would comply with the MATS standard is meaningless.

Review of emission calculation provided by the Applicant in the AFC proceeding before the CEC shows that the PDOC's claim regarding MATS compliance is not supported. The Applicant estimated maximum annual mercury emissions from the facility based on firing 100% coal from the El Segundo mine in New Mexico with a typical mercury content (dry basis) of 0.13 ppmw, a gasifier coal feed of 5,023 tons/day (dry basis), 85% diversion of exhaust flow to feedstock dryer, 75% feedstock dryer removal efficiency, and a >99% removal efficiency for the syngas mercury adsorber bed. These assumptions result in a mercury emission rate for the HECA Project of

[437] PDOC, p. 10.

0.00288 lb/GWh (gross), merely 0.00012 lb/GWh (gross) lower than the MATS standard.[438]

The slightest variability in the Applicant's assumptions could result in the estimated emission rate exceeding the MATS standard. For example, coal from the El Segundo mine shows large variability in mercury content with a maximum of 0.25 ppmw (dry basis).[439] The PDOC contains neither a restriction on the mercury content in the feedstock nor on the origin of the coal. Thus, depending on which area of the mine is extracted, the coal feedstock for the HECA Project could have a considerably higher mercury content than the typical mercury content of 0.13 ppmw assumed by the Applicant. Assuming a mercury content of 0.144 ppmw or higher and otherwise relying on the Applicant's assumptions would result in a mercury emission rate in excess of the MATS standard for mercury of 0.003 lb/GWh. This example illustrates the uncertainty associated with the Applicant's calculations and casts doubt on the facility's ability to comply with the MATS standard for mercury.

Further, it appears that the manufacturer of the mercury activated carbon adsorber beds guarantees the removal efficiency only for a mercury inlet concentration of 20 micrograms per normal cubic meter ("µg/Nm^3").[440] At the higher mercury inlet concentrations of up to 43 µg/Nm^3") expected by the Applicant's engineering firm Fluor for off-design conditions, the manufacturer of the mercury adsorber beds only "expects" a >99% removal efficiency but does not appear to provide a guarantee.[441] Thus, depending on the circumstances of these off-design conditions, mercury

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[438] *See* HECA Response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[439] *See* Attachment B (APS/Pacific Corp Fuel Contracts Excerpts: Typical Analysis for El Segundo) to Conrad Spencer, APS, Cholla Steam Electric Station, Letter to Trevor Baggiore, Arizona Department of Environmental Quality, Re: Request for Additional Information for BART Analysis of Cholla Units 2, 3, and 4, June 18, 2009; http://www.azdeq.gov/environ/air/haze/download/110810g.pdf.

[440] Patrick Flanagan, Norit Americas, Inc., Email to Jim Loney, Fluor, Re: Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, February 7, 2013; provided by HECA in response to Sierra Club Data Request No.144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[441] Patrick Flanagan, Norit Americas, Inc., Email to Robert Gross, Fluor, Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, January 25, 2013; provided by HECA in response to Sierra Club Data Request No. 144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

emissions from the HECA Project could be considerably higher than calculated, particularly during the commissioning period, exceeding the MATS standard.

Sierra Club recommends that the District scrutinize the Applicant's other assumptions for calculations of mercury emissions from the HECA Project. The revised PDOC should heed the EPA's recommendations in its comments on the PDOC for the prior HECA application (08-AFC-8). Specifically, for those sources where emission estimates and/or emission limits were relatively close to a threshold, the EPA recommended "a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or b) a 5-10% buffer between the permitted emission limits and the federal threshold."[442] Further, the revised PDOC should take care to only include the significant figures warranted by the input parameters for the calculation.

Lack of Adequate Compliance Conditions to Demonstrate Compliance with the MATS Standard

In order to demonstrate compliance with the calculated emission rates for the HECA Project as calculated by the Applicant and relied upon by the District to find that mercury emissions would comply with the MATS standards (*see* Comment VII), Sierra Club recommends that the District revise the PDOC to include enforceable permit conditions restricting the feedstock mercury content, gasifier feed rate, etc.

Further, the PDOC's assumption that mercury emissions would be below the MATS standard rely on the Applicant's calculations which assume a 99% removal efficiency of the mercury adsorber beds in the mercury removal unit. The manufacturer of these mercury adsorber beds provides a conditional guarantee:

> Norit RBHG 3 is conditionally guaranteed to achieve >99% removal of mercury for three years. The performance guarantee is based on a minimum bed residence time of 10 seconds at a velocity of less than 60 fpm. Operating conditions for the system must not exceed 60 degrees C, and must have less than or equal to 20 micrograms/Nm3 mercury concentration at the inlet of the carbon adsorber.[443]

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[442] Gerardo Rios, EPA, Letter to David Warner, SJVAPCD, Re: EPA Comments on Project Number S-1093741 (08-AFC-8), August 16, 2010; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/others/2010-08-16_EPA_Comments_TN-58112.pdf.

[443] Patrick Flanagan, Norit Americas, Inc., Email to Jim Loney, Fluor, Re: Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, February 7, 2013; provided by HECA in response to Sierra Club Data Request #144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Thus, the PDOC must incorporate monitoring provisions to guarantee the above specified operating conditions to ensure that HECA's mercury emissions are indeed below the MATS standard of 0.003 lb/GWh as calculated. While the manufacturer "expects" that the adsorber bed would still provide a >99% efficiency at higher mercury concentrations of up to 43 µg/Nm^3 during off-design conditions, the guarantee is restricted to 20 µg/Nm^3.[444]

Sierra Club further recommends that facility demonstrate compliance with mercury limits via source stack testing and using a continuous emissions monitor ("CEMS") for particulate matter rather than only periodic source testing for particulate matter as proposed by the Applicant.[445]

VII.F Summary

As discussed above, the PDOC's compliance conditions identify the Project as a major source of HAPs. Even if the respective condition is revised to correspond with the Applicant's revised emission estimates, the PDOC (by wholesale accepting the Applicant's emission calculations) failed to account for the full potential to emit for HAPs because it failed to account for all emission sources and pollutants and did not rely on conservative assumptions. When these errors corrected, emission estimates exceed the trigger thresholds of 10 tons/year for individual HAPs and likely the trigger threshold of 25 tons/year for total HAPs. Therefore, the facility is a major source of HAP emissions requiring toxics BACT ("T- BACT").

VIII. THE PDOC'S AMBIENT AIR QUALITY IMPACT MODELING AND HEALTH RISK ASSESSMENT REPORT IS FLAWED

The PDOC presents an ambient air quality impact modeling and health risk assessment report for the HECA Project in Appendix K. This AAQI/HRA report is not adequately supported and is flawed.

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[444] Patrick Flanagan, Norit Americas, Inc., Email to Robert Gross, Fluor, Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, January 25, 2013; provided by HECA in response to Sierra Club Data Request #144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[445] HECA Response to Sierra Club Data Request #146, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

VIII.A Lack of Support

The AAQI/HRA Report describes emission scenarios and summarizes source stack parameters[446] but fails to quantify the emission rates from the respective sources that were modeled. As discussed in Comment VII.B, the emission rates summarized by the PDOC in Appendix H are outdated and are lower than the revised estimates provided by the Applicant to the CEC and Sierra Club on January 10, 2013. It is unclear which emission rates the PDOC's modeling relies upon. Thus, the results of the ambient air quality modeling and the PDOC's conclusion that HECA Project emissions would not result in significant health impacts are not adequately supported.

As discussed in Comments V & VII, the PDOC did not account for worst-case, or maximum, emissions from the HECA Project because, for example, it did not account for malfunction emissions and underestimated criteria pollutant and HAP emissions from a number of sources, including the CO_2 vent, fugitive equipment leaks. These errors were likely carried over into the modeling for the AAQI/HRA Report. Therefore, the results of the PDOC's AAQI/HRA Report with respect to the HECA Project's air quality and health impacts cannot be relied upon.

VIII.B NO_2/NOx In-stack Ratio for Heat Recovery Steam Generator

Despite the lack of any actual data for turbines burning hydrogen-rich gas, the PDOC assumes a NO_2/NOx in-stack ratio lower than the EPA-recommended default value of 0.5 that can be used without further justification. The PDOC states that "HECA proposes to use the conservative NO_2/NOx in-stack ratio of 0.3 for all turbine and dryer operating conditions" based on "professional engineering estimate" from the turbine and oxidation catalyst vendors.[447] Yet for purposes of modeling NO_2 concentrations, the PDOC specifies an even lower NO_2/NOx in-stack ratio of 0.2 for the HRSG.[448] The PDOC provides no explanation of why it assumed and modeled a lower in-stack NO_2/NOx ratio than proposed by HECA and estimated by the equipment vendors. The HRSG is the largest source of the Project's operational NOx emissions and the modeled concentrations of 1-hour NO_2 concentrations including the background (325 $\mu g/m^3$) are very close to the 1-hour CAAQS (339 $\mu g/m^3$).[449] Thus, an increase in the NO_2/NOx in-stack ratio could result in exceedances of the 1-hour CAAQS for NO_2. The District must assume the most conservative NO_2/NOx ratio for modeling purposes.

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[446] PDOC, pp. 18, 42, and 56.

[447] PDOC, Appx. K, p. 47.

[448] PDOC, Appx. K, Table 8-4, p. 47.

[449] PDOC, Appx. K, Table 8-5, p. 49.

VIII.C Startup Emissions Are Not Modeled

EPA presently provides no exemption from complying with NAAQS during periods of (1) testing/maintenance or actual emergency operation, and (2) startup. From our review of the modeling files, it appears that the Applicant did not model peak one-hour startup, shutdown, and emergency related NO_2 and SO_2 emissions from all the sources.

VIII.D The PDOC's Finding that 24-hour PM10 Impacts Are Less than the Significant Impact Level Is Based on Flawed Emission Rate Calculations and Inappropriate Model Inputs

Sierra Club previously submitted comments regarding the HECA Project's modeled 24-hour PM10 impacts to the District and the CEC.[450] Below, we revise and expand our earlier comments to include our modeling results, including the actual emissions tables, modeling methodology and results:

The PDOC finds that the 24-hour PM10 impacts from the proposed HECA project will be 4.90 $\mu g/m^3$.[451] This impact represents 98% of the 24-hour PM10 significant impact level ("SIL"), which is 5.0 $\mu g/m^3$. Had the HECA Project impacts exceeded the SIL, then extensive modeling analyses would have been required to verify whether project emissions, in conjunction with surrounding emission sources, will lead to violations of the applicable PM10 PSD increments and NAAQS.[452] Since the PDOC does not identify HECA PM10 impacts above the SIL, these additional modeling analyses were not performed.

The PDOC's finding of less than significant PM10 impacts is based on flawed emission rate calculations, as discussed in Comment V, and inappropriate AERMOD model inputs, as discussed below. These flawed emission rate calculations and model inputs lead to under-predicted modeled impacts and incorrect findings of insignificance. When corrected, the 24-hour PM10 impacts from the proposed HECA Project will exceed the respective SIL and will violate applicable regulatory design concentrations. In particular, the 24-hour PM10 PSD increment of 30 $\mu g/m^3$ and the 50 $\mu g/m^3$ 24-hour PM10 CAAQS are sensitive standards that will be violated when corrected emission rates are used for modeling.

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[450] Andrea Issod, Sierra Club, Letter to Dave Warner, SJVAPCD, and Robert Worl, CEC, Re: Preliminary PM Modeling Comments on the PDOC for the HECA Project (08-AFC-08A), April 26, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-26_Sierra_Club_Comments_on_PDOC_TN-70503.pdf.

[451] PDOC, Appx. K, p. 49.

[452] SJVAPCD Rule 2410 and PDOC, Appx. K, p. 8.

In addition, the San Joaquin Valley already experiences very high PM10 levels, which are very close to putting the region back into nonattainment status for this pollutant. The PM10 impacts from the HECA Project only add to this concern and could jeopardize the current PM10 attainment status in the southern San Joaquin Valley. It is essential that the PDOC include a complete and proper analysis of HECA PM10 impacts. The 24-hour PM10 emission rates must be corrected and completely reassessed with updated modeling analyses in the PDOC.

VIII.D.1 The PDOC Underestimates 24-hour PM10 Impacts Because It Uses Inappropriate Paved Road Emission Calculations

HECA modeled fugitive dust PM10 emissions from onsite paved roads.[453] These emission sources often cause the highest modeled impacts from an industrial source, due to the low-level and non-buoyant nature of how they are released to the air. The paved road PM10 emissions calculated by HECA, however, use incorrect inputs, as discussed in Comment V.B.9.a above, resulting in substantially under-predicted emission rates and subsequent modeled impacts. These shortcomings are then carried over into the SJVAPCD's PDOC's modeling.

Revised Emission Rates

We revised the emission rates for on-site paved roads using very conservative assumptions:

- We recalculated the paved road fugitive PM10 emissions from Operation & Maintenance vehicles, Product Trucks, Coal/Coke Feedstock Trucks, and Miscellaneous Delivery Trucks using a conservatively low silt loading rate of 1.6 g/m^2. This results in an emission increase for these sources of a factor of 36.1918.
- We recalculated the paved road fugitive PM10 emissions from Product Trucks, Coke Feedstock Trucks, and Miscellaneous Delivery Trucks using an unloaded truck weight of 20 tons. This results in an emission increase for these sources of a factor of 1.8803.
- We recalculated the 24-hour paved road fugitive PM10 emissions from all onsite vehicles using no rainfall correction. This results in an emission increase for these sources of a factor of 1.0253.

The corrected 24-hour paved road fugitive PM10 emissions from all onsite vehicles are shown in the table below. These emission rates include combustion PM10 emissions as calculated and modeled by the Applicant.

[453] Paved road fugitive dust PM10 emissions were added to onsite vehicle combustion PM10 emissions.

Table 6a: PM10 Emissions from all Onsite Vehicles

Emission Source (modeled as volume sources)	**Applicant PM10 Emissions** (g/s)	**Corrected PM10 Emissions** (g/s)
Product Trucks (modeled as PTRK1 – PTRK73)	4.7117E-05	2.7538E-03
Coal/Coke Trucks (modeled as CTRK1 – CTRK34)	1.6417E-05	9.5952E-04
Misc. HHDT Delivery Trucks (modeled as MISCTRK1 – MISCTRK5)	6.1158E-04	1.5859E-03
Onsite O&M Trucks (modeled as OMTRK1 – OMTRK10)	2.1722E-04	3.0393E-03

VIII.D.2 The PDOC Underestimates 24-hour PM10 Impacts Because It Uses Inappropriate AERMOD Model Inputs

In addition to the under-estimated PM10 emission rates discussed above, the PDOC also uses flawed modeling methods to predict 24-hour PM10 ambient air concentrations. These model inputs are:

- The PDOC modeling uses ground-level receptors, rather than a flagpole height of 1.5 meters for human inhalation.

- The PDOC modeling uses Bakersfield airport meteorological data processed with outdated methods.

Each of these inappropriate model inputs are discussed below.

Flagpole Receptors

Receptors are locations where the AERMOD dispersion model calculates ambient air concentrations. These receptors are designated by the model user and include the geographical coordinate of the receptor, the elevation above sea level of the receptor, and the receptor height above the ground (known as flagpole height).

The PDOC modeling does not incorporate a receptor flagpole height, which results in the model calculating air concentrations at the surface of the ground. Since the HECA property boundary is less than a few hundred meters from their emission sources, a flagpole receptor height of about 1.5 meters should have been included in the PDOC modeling.[454] This corresponds to an average breathing zone of a person and will provide a better estimate of project-caused air impacts.

[454] California Environmental Protection Agency, Air Toxics Hot Spots Program Risk Assessment Guidelines, Technical Support Document for Exposure Assessment and Stochastic Analysis, August 2012, p. 2-19; http://www.oehha.ca.gov/air/hot_spots/pdf/2012tsd/TSDportfolio2012.pdf.

Meteorological Data

The PDOC modeling uses 2006 through 2010 Automated Surface Observation Station ("ASOS") meteorological data collected at Meadows Field Airport, in Bakersfield. These ASOS data, however, are based on a single two-minute observation near the end of each hour and are not representative of a valid hourly-average. Furthermore, the meteorological data used in the PDOC modeling include over 27% calm hours, which are unusable by AERMOD. This large percentage of calm hours is a simple artifact of the standard ASOS reporting methods. Overstating the number of calm hours tends to result in under-predicted modeled impacts since the low wind speed conditions often associated with peak impacts are artificially excluded from the modeling analysis.

EPA has been aware of this issue for several years, and on February 28, 2011, EPA finalized a revised version of AERMET, along with a pre-processor program called AERMINUTE.[455] AERMET is the program that creates the meteorological data sets used by AERMOD. The revised version of AERMET (including AERMINUTE), can process one-minute airport data, thus correcting the reporting artifact that causes an unrealistically high number of calm hours in the data sets. EPA, state, and local air agencies now routinely use the revised AERMET and AERMINUTE programs for modeling compliance with ambient air quality standards. In their modeling guidance for SO_2 NAAQS designations, EPA discussed the concern of calm hours in underestimating air impacts:

> In AERMOD, concentrations are not calculated for variable wind (*i.e.*, missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO_2 NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.[456]

At the 10th Conference on Air Quality Modeling, held in March 2012, EPA stated that the purpose of the revised AERMET and AERMINUTE programs is "not to

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[455] EPA, Addendum, User's Guide for the AERMOD meteorological Processor (AERMET), EPA-454/B-03-002, November 2004, (v. 12345, released publicly in December 2012). http://www.epa.gov/ttn/scram/7thconf/aermod/aermet_userguide.zip.

[456] EPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19. http://www.epa.gov/air/sulfurdioxide/pdfs/20110411so2designationsguidance.pdf.

introduce conservatism" into the model, but rather to "Reclaim data that was "lost" due to coding, making station more representative."[457] Furthermore, EPA "recommends that AERMINUTE should routinely be used to supplement the standard NWS data with hourly-averaged winds based on the 1-minute ASOS wind data (when available)."[458]

These recommendations have also been presented in a March 2013 Clarification Memo from EPA:[459]

> Given the limitations and significant concerns regarding the adequacy of standard ASOS data, and considering the relevant recommendations in the *Guideline* related to these concerns, we recommend that AERMINUTE be routinely used to supplement the standard ASOS data with hourly-averaged wind speed and direction to support AERMOD dispersion modeling. Since the 1-minute ASOS wind data used as input to AERMINUTE are freely available to the public, this recommendation should not impose any significant burden on permit applicants applying the AERMOD model.[460]

EPA summarizes the recommended use of ASOS meteorological data as follows:

- EPA has developed the AERMINUTE processor to calculate hourly average winds from 1-minute ASOS winds, whose purpose is to replace the single 2-minute winds that represent an hour with an hourly-averaged wind that is reflective of actual conditions and more appropriate for input for dispersion modeling.
- EPA recommends that AERMINUTE be routinely used in general practice in AERMOD modeling as the hourly average winds better reflect actual conditions over the hour as opposed to a single 2-minute observation.
- EPA has also implemented a threshold option in AERMET to treat winds below the threshold as calms, with a recommended minimum wind speed of 0.5 m/s, consistent with the threshold required for site-specific data.[461]

The SJVAPCD also has procedures that apply AERMINUTE and one-minute

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[457] James Thurman, EPA/OAQPS, AERMINUTE, 10th Conference on Air Quality Modeling. http://www.epa.gov/ttn/scram/10thmodconf/presentations/1-7-aerminute_update.pdf.

[458] Roger Brode, EPA/OAQPS, Appendix W: Clarification Memoranda, 10th Conference on Air Quality Modeling. http://www.epa.gov/ttn/scram/10thmodconf/presentations/1-4-Brode_10thMC_AppW_ClarificationMemos_03-13-2012.pdf.

[459] EPA, Use of ASOS Meteorological Data in AERMOD Dispersion Modeling, March 8, 2013. http://www.epa.gov/ttn/scram/guidance/clarification/20130308_Met_Data_Clarification.pdf.

[460] *Id.*, p. 12.

[461] *Id.*, p. 13.

ASOS winds.[462] From the SJVAPCD Procedure for Downloading and Processing NCDC Meteorological Data:

> To reduce the number of calms and missing winds in the surface data, archived 1-minute winds for the ASOS stations can be used to calculate hourly average wind speed and directions, which are used to supplement the standard archive of hourly observed winds processed in AERMET (EPA, 2010b).

At a minimum, the PDOC modeling should be based on 2008 through 2012 Meadows Field Airport meteorological data, which incorporate one-minute wind data processed with EPA's AERMINUTE program. A threshold wind speed of 0.5 meter per second should also be applied to the AERMET processing of these data.

We prepared 2008 through 2012 Meadows Field Airport meteorological data incorporating EPA's recommended use of AERMINUTE and one-minute wind data. This improved meteorological data set has about 4.4% calm winds, compared to the 27% calm winds found in the 2006 through 2010 PDOC modeling data set. Our modeling analysis using the more representative meteorological data found significantly higher 24-hour PM10 impacts than were predicted using the less representative 2006 through 2010 data.

Methods Used to Prepare 2008 – 2012 Meteorological Data

The meteorological data required by AERMOD is prepared by AERMET. Required data inputs to AERMET are: surface meteorological data, twice-daily soundings of upper air data, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. [463] AERMET creates the model-ready surface and profile data files required by AERMOD. Using AERMET v. 12345, we created an AERMOD-ready meteorological data set to model the proposed HECA facility. This data set covered five years, 2008 through 2012, and is summarized as follows:

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[462] SJVAPCD, Procedure for Downloading and Processing NCDC Meteorological Data, Final, Version 3.1, April 2013, p. 8. http://www.valleyair.org/busind/pto/Tox_Resources/MeteorologicalDataProcessing4-11-13.pdf.

[463] Albedo is the fraction of total incident solar radiation reflected by the surface back to space (whiter surfaces have higher albedo). The Bowen ratio is an indicator of surface moisture. It is the ratio of sensible heat flux to latent heat flux and drier areas have a higher Bowen ratio. Surface roughness, shown in shorthand as ("z_0"), is an essential parameter in estimating turbulence and diffusion. Technically, it's the height above the ground that the log wind law extrapolates to zero. For our purposes, z_0 can be thought of as a measure of how much the surface characteristics interfere with the wind flow. Very smooth surfaces, like short grass or calm ponds, have very low values of z_0 -- on the order of 0.01 meter or less. Tall and irregular surfaces, which are a greater obstacle to wind flow, have higher values of z_0 – up to 1.0 meter or more for forests.

Meteorological data used for modeling the HECA facility:
- Surface data: Meadows Field Airport (KBFL);
- Upper air data: Oakland International Airport (KOAK).

Surface Meteorological Data

We used 2008 through 2012 Integrated Surface Hourly ("ISH") data obtained from the National Climatic Data Center ("NCDC"). From the ISH dataset, we extracted ASOS data from the Meadows Field Airport.

We also obtained 2008 through 2012 one-minute ASOS wind data from the Meadows Field Airport, which we processed with AERMINUTE v. 11325. We downloaded these one-minute data from the NCDC.[464] We input the ice-free wind instrument start date (March 14, 2007) and used default settings with AERMINUTE. As a quality assurance measure, we compared values developed from the one-minute data with the corresponding ISH data file.

We processed the ISH data through AERMET Stage 1, which performs data extraction and quality control checks. We merged the AERMINUTE output files with the processed AERMET Stage 1 ISH and upper air data in AERMET stage 2.

Upper Air Meteorological Data

We used 2008 through 2012 upper air data from twice-daily radiosonde measurements obtained from Oakland International Airport. These data are in Forecast Systems Laboratory ("FSL") format which we downloaded in ASCII text format from the FSL website maintained by the National Oceanic and Atmospheric Administration ("NOAA").[465] We downloaded and processed all reporting levels with AERMET.

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. We processed the FSL upper air data through AERMET Stage 1, which performs data extraction and quality control checks.

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[464] *See*: ftp://ftp.ncdc.noaa.gov/pub/data/asos-onemin/.

[465] Available at: http://esrl.noaa.gov/raobs/.

AERSURFACE and Final Processing

We used AERSURFACE v. 13016 to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site (Meadows Field Airport). Using AERSURFACE, we extracted surface roughness in a one kilometer radius surrounding the data collection site. We also extracted Bowen ratio and albedo for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. We processed these micrometeorological data for seasonal periods using 30-degree sectors.

We applied the AERSURFACE outputs in Stage 3 AERMET processing. At this point, we also incorporated a 0.5 meter/second threshold velocity for one-minute ASOS winds that had been processed with AERMINUTE. We did not fill missing hours in the meteorological data sets as the data files exceed USEPA's 90% data completeness requirement.[466]

Modeling Results

The corrected HECA PM10 impacts include revisions to paved road fugitive emissions, modeling with receptor flagpole heights, and using 2008 through 2012 Bakersfield meteorological data processed with current USEPA recommendations. Using AERMOD v. 12345, our modeling results for 24-hour average PM10 impacts are presented below.

The 24-hour PM10 Significant Monitoring Concentration (10 $\mu g/m^3$) and the 24-hour PM10 CAAQS (50 $\mu g/m^3$) are based on highest modeled 24-hour impacts. Our modeling analysis incorporating fugitive dust emission rate and modeling corrections shows that HECA's 24-hour PM10 impacts will exceed both of these regulatory design concentrations. The highest 24-hour average PM10 impacts from the HECA project are shown in the following table:

[466] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 – 5-5. http://www.epa.gov/ttn/scram/guidance/met/mmgrma.pdf.

Table 6b: 24-hour PM10 Significant Monitoring Concentration

Year of Meteorological Data	Highest 1st High 24-hr PM10 Concentration ($\mu g/m^3$)	Easting Coordinate (meters)	Northing Coordinate (meters)
2008	55.59	283970.70	3912099.90
2009	42.42	283982.40	3912599.80
2010	34.23	283966.70	3911925.00
2011	47.16	283973.10	3912199.90
2012	39.33	283971.90	3912149.90

The 24-hour PM10 PSD increment (30 $\mu g/m^3$) is based on the second-highest modeled 24-hour impact for each year modeled. Our modeling analysis incorporating fugitive dust emission rate and modeling corrections shows that HECA's 24-hour PM10 impacts will exceed this regulatory design concentration. The second-highest 24-hour average PM10 impacts from the HECA project are shown in the following table:

Table 6c: Second-Highest 24-hour PM10 Significant Monitoring Concentration

Year of Meteorological Data	Highest 2nd High 24-hr PM_{10} Concentration ($\mu g/m^3$)	Easting Coordinate (meters)	Northing Coordinate (meters)
2008	46.25	283970.70	3912099.90
2009	34.79	283965.50	3911875.00
2010	32.96	283972.50	3912174.90
2011	34.02	283970.70	3912099.90
2012	35.15	283971.90	3912149.90

VIII.D.3 Revised Modeling Results Indicate that HECA's 24-hour PM10 Impact Exceeds Regulatory Design Concentrations

The PDOC finds that the HECA's 24-hour PM10 impact is 98% of the 24-hour PM10 SIL. This finding, however, is based on underestimates in the emission rate calculations and improper model inputs. Correcting the inappropriate paved road PM10 emissions, and correcting the model inputs identified above, will result in 24-hour PM10 impacts much greater than the SIL. In fact, these corrections will lead to violations of the following regulatory design concentrations:

– The 24-hour PM10 Significant Monitoring Concentration (10 $\mu g/m^3$),

- The 24-hour PM10 PSD increment (30 µg/m^3), and
- The 24-hour PM10 CAAQS (50 µg/m^3).

In addition, the corrected PM10 impacts from the HECA project may cause or contribute to PM10 NAAQS violations in an area that is very close to becoming nonattainment for this pollutant.

None of these significant impacts were identified in the PDOC due to the incorrect finding that the 24-hour PM10 impacts are below the SIL. The PDOC must be revised to incorporate the corrected 24-hour PM10 emission rates and subsequent modeling analyses.

IX. THE PDOC FAILS TO ADDRESS NUISANCE AND POTENTIAL INJURY OR DAMAGE TO BUSINESS OR PROPERTY

The PDOC does not address the potential impacts of HECA on nearby businesses and properties. District Rule 4102, Section 4.1, requires:

> A person shall not discharge from any source whatsoever such quantities of air contaminants or other materials which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such person or the public or which cause or have a natural tendency to cause injury or damage to business or property.

The PDOC must evaluate the Project's potential direct and indirect impacts on local farms and other businesses, including emissions and materials from the facility as well from all of the associated trains and trucks.

Fugitive coal dust along rail lines is a major concern. Although HECA first indicated that coal will be shipped using covered rail cars, it subsequently disclosed that the coal will be shipped in open-top rail cars.[467] Publicly available testimony from coal companies before the Surface Transportation Board (STB) states that each rail car loses between 250 and 700 pounds of coal and coal dust on each trip for an average loss of 500 pounds of coal lost from each car per trip.[468] The local citizen group Association of Irritated Residents ("AIR") recently posted a report including video footage to the

[467] HECA Responses to CEC Workshop Requests: Nos. A33 through A37, December 2012, p. 5; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-12-19_Applicants_Responses_to_Requests_A33-A37_TN-68931.pdf.

[468] Hearing Transcript and Recording, July 29, 2010, Arkansas Electric Cooperative Association – Petition for Declaratory Order, Surface Transportation Board, Docket No. FD 35305, tape 1 at Transcript (Tr.) at 102:9-103:7, 37:07, 1h:42; Tr. at 42:5-13, 102:9-103:7 (BNSF Testimony).

CEC demonstrating that there are already large amounts of coal spillage along the BNSF railroad in Kern County between Bakersfield and Wasco.[469]

Air pollution and coal dust from the trains may have adverse impacts on crops – a major component of the region's economy – that far outweigh any alleged economic benefits.[470] The proposed project site is surrounded by highly productive agricultural land where pistachios, almonds, alfalfa, grapes, onions, tomatoes, wheat, cotton, and other crops are grown. Agricultural crops can be injured when exposed to high concentrations of various air pollutants. Injury ranges from visible markings on the foliage, to reduced growth and yield, to premature death of the plant. For example, alfalfa crops are susceptible to sulfur dioxide pollution that HECA would emit.[471] The local farming community has expressed numerous concerns about how the HECA project may impact or contaminate soils, crop yields and crop value.[472]

> All we need, all we need here in this area is for one scare, one scare to come from this plant to say that there's something in the air, there's something in the soil, there's something coming from this plant that is polluting our crops. Whether it be pistachios or almonds or cherries or grapes or any other product that's grown in this area. And then we get a call from our processors that say, I don't think we want your product anymore because of your proximity to that plant and what can happen to this -- to your products and could devastate the entire product.[473]

The District must evaluate how increased air pollution from the HECA project and transportation corridors would impact the crops in the area surrounding the plant. The analysis should include direct impacts to the crops as well as indirect impacts to the soil and irrigation water and economic impacts.

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[469] Status Report Six from the Association of Irritated Residents (AIR), April 11, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-11_AIR_status_report_06_TN-70272.pdf.

[470] These impacts should also be evaluated in the District's alternatives analysis under section 173(a)(5).

[471] Ontario, Ministry of Agriculture, Food and Rural Affairs, Revision of Factsheet, Air Pollution on Agricultural Crops, Order No. 85-002, printed June 2003; http://www.omafra.gov.on.ca/english/crops/facts/01-015.htm.

[472] For example, email exchange between Robert Worl, CEC, and Chris Romanini, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2013-02-28_CEC_Email_Exchange_with_Intervenor_HECA_Neighbors_C_Romanini_Regarding_Air_Quality_and_Water_TN-69828.pdf; and HECA Reponses to AIR Data Requests Nos. 12 through 42, November 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Responses_to_AIR_Data_Requests_Nos_12_through_42_TN-68731.pdf.

[473] Informational Hearing and U.S. Department of Energy Scoping Meeting before the Energy Resources Conservation and Development Commission of the State of California, In the Matter of the: Amended Application for Certification for the Hydrogen Energy Project, Docket No. 08-AFC-08A, July 12, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2012-07-12_Transcript_of_Informational_Meeting_TN-2933.pdf

X. OTHER COMMENTS AND RECOMMENDATIONS

The PDOC's formulaic structure, which clings to a generic outline provided by the District, results in an impenetrable document that is not adequate to inform the public of the consequences of this complex project. The document could be much improved by revising its organization. Further, the document includes a number of erroneous statements, imprecise descriptions, and typographical errors:

Organization

- Sierra Club recommends that the District include a more detailed table of contents including subheadings for both the main document and the appendices to improve navigability of the document.

- Sierra Club recommends that all assumptions and calculations are contained within in one section for each emissions unit rather than first laying out all assumptions for all emissions units, then calculating PTE for all emissions units, then determining BACT for all emissions units, etc. which makes the PDOC difficult to follow especially given the lack of a detailed table of contents.

- Sierra Club recommends that the facility-wide general conditions repeated for each permit unit at the beginning of their respective compliance conditions in Appendix A be separated from the unit-specific conditions and presented in a separate facility-wide section. This facility-wide section should also include the compliance conditions addressing fugitive dust, which are repeated at end of each permit unit.

- Sierra Club recommends that the respective permit unit ID be repeated in the header of the section containing the compliance condition for each emission unit.

- Sierra Club recommends that the title of Appendix F "Emission Information" be revised to specifically refer to HRSG and coal drying stack operating scenarios.

Erroneous Statements and Content

- The PDOC, Appendix K, p. 48, provides that the refined ambient air quality standard analysis demonstrates "that emissions from HECA will not cause or contribute to exceedance of a NAAQS and/or CAAQS for any affected pollutant." Yet the results of the analysis presented in Table 8-5, provided on the next page, contradict this statement showing that HECA emissions will

contribute significantly to existing exceedances of the 24-hour and annual PM10 and PM2.5 NAAQS, 24-hour PM10 CAAQS, annual PM2.5 CAAQS.

- The PDOC, Appendix K, Table 8-5, p. 49, incorrectly references the annual CAAQS for PM2.5 at 15 $\mu g/m^3$ instead of 12 $\mu g/m^3$.

- The PDOC, Table 6-2, p. 12; Appendix K, Table 8-1, p. 37; Appendix K, Table 8-5, p. 49, and Appendix K-A, p. 64; incorrectly reference the superseded annual NAAQS for PM2.5 of 15 $\mu g/m^3$ instead of the new annual NAAQS of 12 $\mu g/m^3$ adopted by EPA on January 15, 2013 and effective March 18, 2013.[474]

Imprecise Description

- The PDOC, p. 59, provides that CO emission factor of 2.0 lb/MMBtu on unshifted syngas from the gasification flare is based on supplier data from "first project". It is unclear which "first project" the PDOC refers to as there have been several revisions to the Project including a change of gasifier technology, change of feedstock blend from 100% petcoke to 75% coal/25% petcoke, and addition of a fertilizer manufacturing facility which resulted in multiple revisions to the AFC process before the CEC. Sierra Club recommends that the PDOC provide a definition of "first project" and discuss why the CO emission factor from that project remains applicable to the HECA Project.

- The PDOC, p. 54, provides that that the breakdown of operation for the maximum duration of venting episodes from the CO_2 recovery and vent system, *i.e.*, a cumulative 504 hours/year, is "explained in the table below" but fails to provide such a table. Presumably, the PDOC refers to the table "Carbon Dioxide Venting Scenarios" on page 31 of the PDOC.

- The PDOC variously refers to the "coal dryer" and "feedstock dryer."

Typographical Errors

- The PDOC, Appendix C, p. C-5: "therefore BACT for SOx emissions is satisfied" should read "therefore BACT for PM10 emissions is satisfied."

- The PDOC, p. 121, incorrectly refers to "Rule 2201 section 4.13.2.2" instead of "Rule 2201 section 4.13.3.2."

[474] 78 Fed. Reg. 3086 (Jan. 15, 2013).

- In Appendix C, p. C-31, the PDOC erroneously refers to a maximum heat input limit for the heater of 7.7 billion Btu per year instead of 7.84 billion Btu.[475]

- The PDOC, Appendix K, p. 121, incorrectly refers to SJVAPCD Rule 2201, Section 4.13.2.2 instead of Section 4.13.3.2.

- The PDOC, p. 81, incorrectly converts emissions from the CO_2 vent of 5,672 lb/year VOC (as methane) to 2.34 tons/year, instead of 2.84 tons/year. The PDOC, Appendix A, p. A-43, implements this incorrect annual emission estimate into condition of compliance No. 9 for the CO_2 recovery and vent system (S-7616-24-0).

- The PDOC, p. 51, refers to the compound "C3H3" as accounted for in the estimate of VOC emissions from fugitive equipment leaks. Presumably, the PDOC instead refers to propylene, or "C_3H_6," which is found in several process streams.

- The PDOC, p. 82, incorrectly refers to equipment unit S-7616-27-0 as "Cooling Tower Serving Power Block and Process Units" instead of "Cooling Tower Serving Gasification Block and Process Units."

[475] PDOC, Appx. C, p. C-31.

Exhibit A

Public Record Request C-2013-2-44: ERC for HECA

Inbox x

Turn on highlighting Print all

Jim Swaney <Jim.Swaney@valleyair.org> Feb 15

to me

David,

Attached is a document that contains the ERC histories for the ERC's that HECA has proposed to use. Once you review this, please let me know what information you would like to receive concerning these ERC's.

One other thing I wanted to let you know about, as you indicated you will be providing comments on the project, is that we have received a request to hold a public hearing about the project, and will therefore extend the public commenting period. Once the hearing is scheduled, we will let you know what the extension on comments will be.

Thanks,
Jim

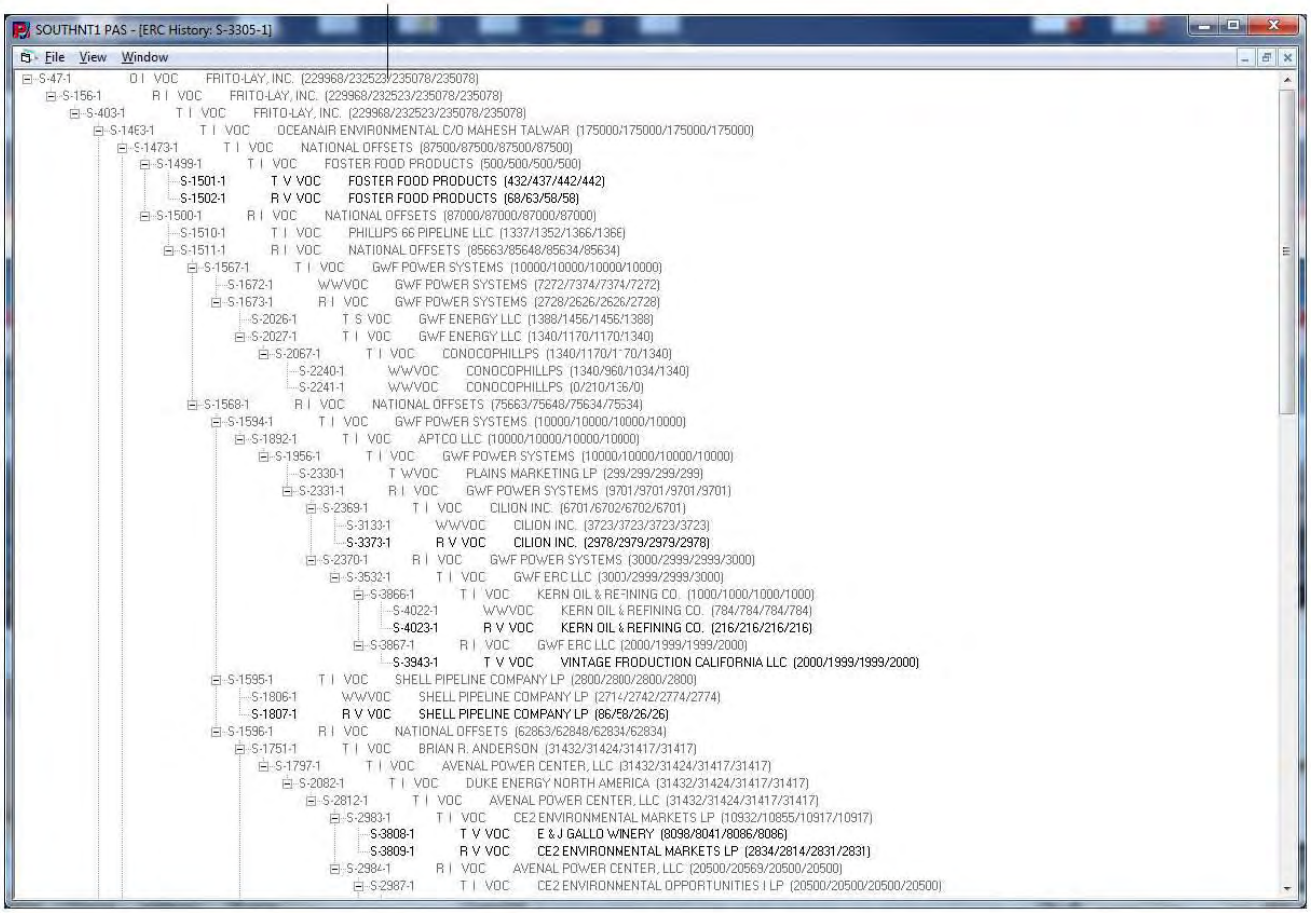
Jim Swaney, P.E.
Permit Services Manager
Valley Air District
(559) 230-6000
(559) 230-6061 fax
www.valleyair.org
www.healthyairliving.com

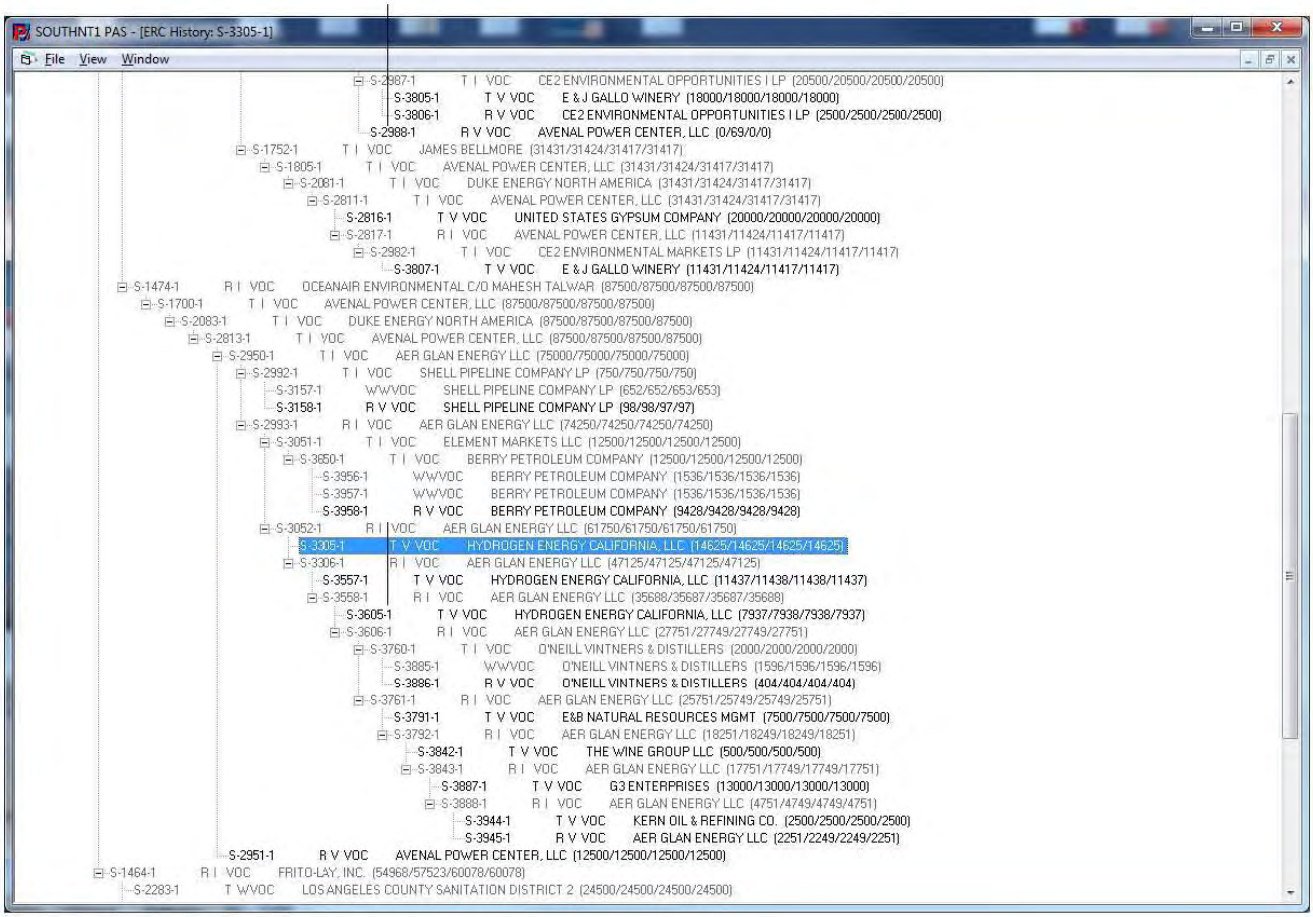
HEALTHY AIR LIVING
www.healthyairliving.com
Make one change for clean air!

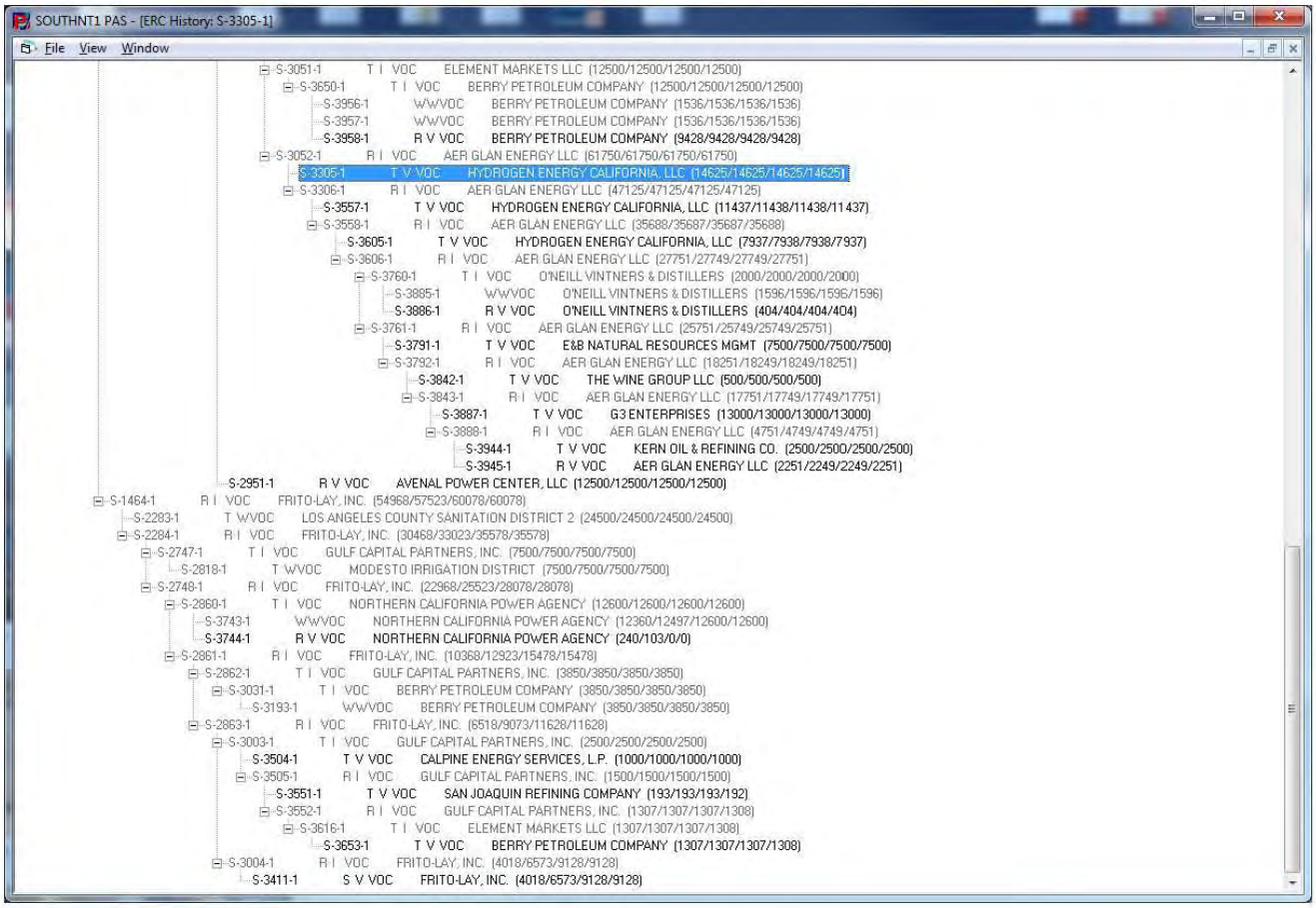
ERC history for HECA ERC.docx
608K View Download

Click here to Reply or Forward

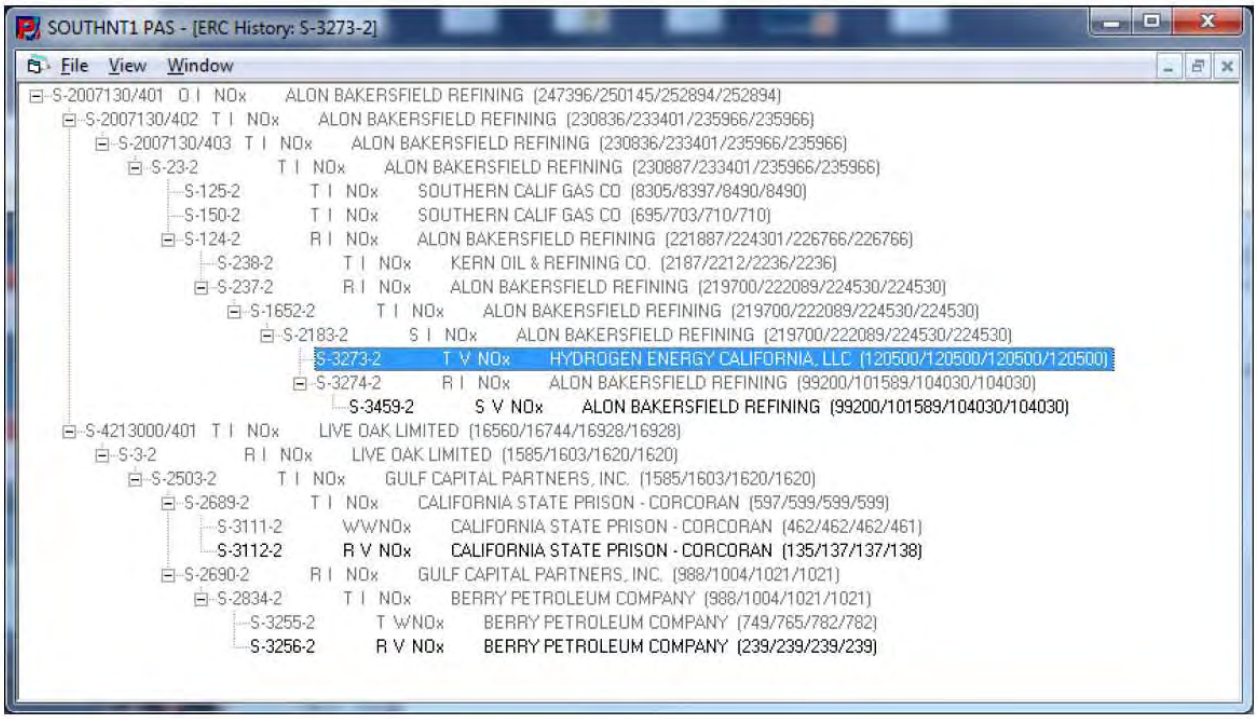
ERC History for S-3305-1, S-3557-1 and S-3605-1



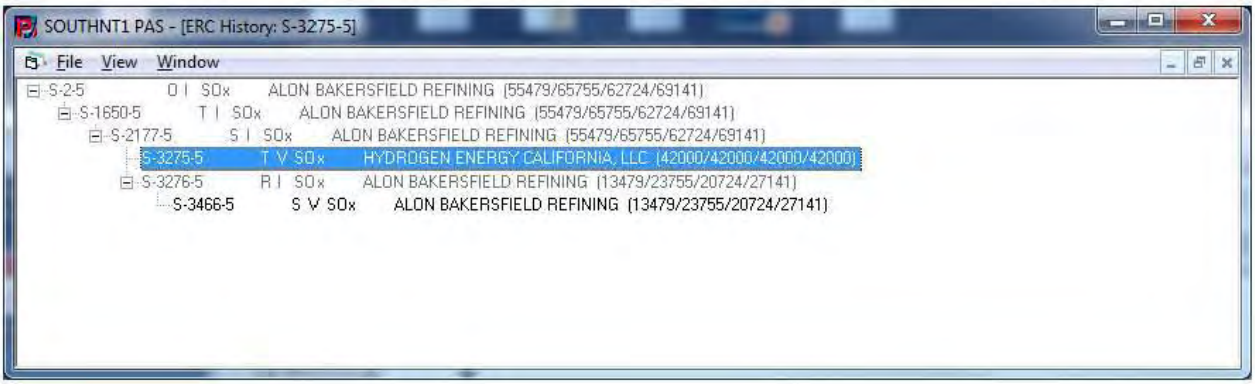




ERC History of S-3273-2



ERC History for S-3275-5



ERC History for C-1058-2

ERC History for C-1058-5

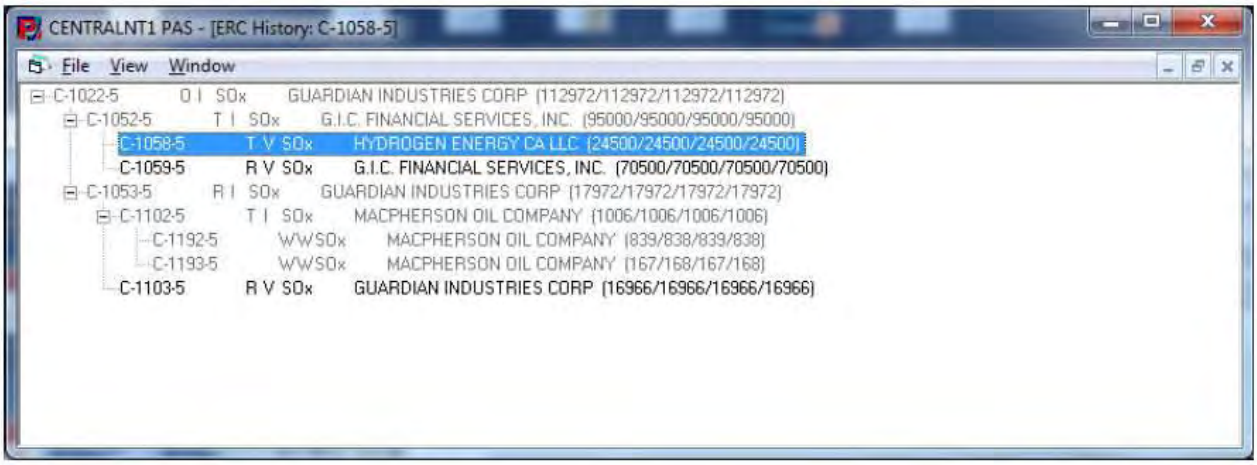


Exhibit B

KERN UNTY AIR POLLUTION CONTROI ISTRICT

1401 "H" Street, Suite 250
Bakersfield, California-93301
Telephone (805) 861-3682

LEON M HEBERTSON, M.D.
Director of Public Health
Air Pollution Control Officer

February 25, 1983

Mr. H. C. Bradbury
Group Manager-Environmental Compliance
Frito-Lay, Inc.
P. O. Box 47250
Dallas, Texas 75247

Dear Mr. Bradbury:

Thank you for your recent letter in which you discuss the Continental Carbon Bakersfield facility's air contaminant emissions. The District has reviewed this facility's specific limiting conditions (contained in Permits to Operate), fuel oil and feedstock average sulfur content (0.8%), and applicable E.P.A. AP-42 emission factors. The following allowable emissions credits were determined from these data. Please note that the hydrocarbon emissions reflect a 50% reduction due to the exclusion of methane. (KCAPCD Rule 210.1 does not allow the use of methane as an emissions tradeoff because it is considered non-photochemically reactive.) The numbers below represent total facility emissions and are in units of lbm/day. Line #1 production rate was considered to be 35.73 tons/day and that of line #2 to be 35.90 tons/day.

Particulates	Carbon Monoxide	Hydrocarbons
560.1	131,848.2	2,388.3
Hydrogen Sulfide	**Oxides of Nitrogen**	**Sulfur Dioxide**
753.4	1,059.4	5,512.8

Even though some of these values are somewhat lower than summarized in your letter, it appears (on the basis of expected emissions summarized in your rough draft A to C applications package) that these emissions credits would provide adequate offsets (at a ratio of 1.2:1) for the Frito-Lay plant proposed for Kern County.

Thank you for your cooperation. Should you have any questions, please telephone the Air Quality Control Division at (805) 861-3682.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Thomas Paxson, P.E., Manager
Engineering Evaluation Section

TP/dl

Exhibit C

ERC APPLICATION REVIEW

6026001/101/201/401/501/601

Facility Name:	FRITO-LAY, INC.	**Project #:**	**6026 920416**
Mailing Address:	222801 Highway 58 Bakersfield, CA 93312	**WP File #:**	92LE026

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

ERC APPLICATION REVIEW

DEEMED COMPLETE:	6/22/92	ENGINEER:	Lance Ericksen
DATE START:	4/16/92	TITLE::	Senior AQE
DATE FINISH:	12/16/92		

6026001/101/201/401/501/601

Facility Name:	FRITO-LAY, INC.	Project #:	6026 920416
Mailing Address:	222801 Highway 58 Bakersfield, CA 93312	WP File #:	92LE038

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

I. **PROPOSAL:**

This review is required to in order revise the amount of NO2 credit and conditions noticed in the preliminary decision to grant ERC Banking Certificates to Frito-Lay. The previous notice was published September 19, 1992. The revisions are necessary to respond to two of the comments received from the applicant during the public comment period:

Comment 1

In the preliminary decision analysis (page 10) the permitted production rate and actual emissions were used to determine the NO2 emission factor. Firto-lay commented the actual production rate during the source test should be used to establish the emission factor. In response to this comment the NO2 emission factor calculation was revised. This results in an increase in the amount of NO2 emission reduction credits previously noticed.

Comment 2

The Banking and New Source Review Rules now in effect contain provisions for the use of shutdown credits and any reductions banked under these rules should be subject to these provisions. The applicant commented that the reductions were limited to use at their snack food facility because the rules that were in effect at the time the reductions were originally recognized did not provide for use of shutdown emissions however, the previous agreements allow the use at their facility. In response to this comment the use of these reductions will not be restricted to the Frito-lay snack food facility.

The remainder of this analysis includes all original pages from the preliminary decision ERC Application Review noticed on September 19, 1992. If a page has not been revised it is noted at the top of the page. If a page is replaced it is shown in strike out after the revised page.

I. **PROPOSAL CONT.:**

In response to comments from Frito-Lay the following emission reductions have been found to qualify for banking:

	Pounds per Quarter				
	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	18,702	229,968	90,000
2nd Qt	25,252	163,500	18,910	232,523	91,000
3rd Qt	25,530	165,296	19,118	235,078	92,000
4th Qt	25,530	165,296	19,118	235,078	92,000

Note: only the amount of NO2 is revised.

Page 1 Continued

ERC APPLICATION REVIEW

DEEMED COMPLETE: 6/22/92 ENGINEER: Lance Erickson
DATE START: 4/16/92 TITLE: Senior AQE
DATE FINISH:

6026001/101/201/401/501/601

Facility Name: FRITO-LAY, INC. Project #: 6026-920416
Mailing Address: 222801 Highway 58 WP File #: 92LE026
Bakersfield, CA 93312

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

I. SUMMARY:

The applicant is requesting ERC Banking Certificates for reductions occurring prior to January 1, 1988. The reductions were obtained from the shutdown of Continental Carbon a carbon black production facility for use as offsets at the Frito-Lay snack food facility. These reductions were recognized in writing by the District as available for offsets prior to adoption of the Kern County banking rule. This allows the applicant to apply for ERC Banking Certificates pursuant to pursuant to Rule 230.1 IV.A.1. As the offsets were previously recognized for use only at the Frito-Lay facility any credits available for banking will also be limited for use at the Frito-Lay Snack Food Facility.

A portion of the original reductions was used for approval of the current Frito-Lay Snack Food Facility in addition a portion of the reductions were donated to the KCAPCD in 1989. The reductions dedicated to previous projects and the portion donated to the District is not surplus and the applicant has not requested to bank these amounts. Of the remaining previously recognized credits the PM10, SO2, VOC and CO qualify for banking as actual emission reductions. The amount of NO2 previously recognized as available for offsets was based on the permit limitation not actual emissions. The amount of NO2 credit requested has therefore been reduced to the remaining actual emissions.

The following emission reductions have been found to qualify for banking:

	Pounds per Quarter				
	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	3,960	229,968	90,000
2nd Qt	25,252	163,500	4,004	232,523	91,000
3rd Qt	25,530	165,296	4,048	235,078	92,000
4th Qt	25,530	165,296	4,048	235,078	92,000

PAGE NOT REVISED

II. APPLICABLE RULES:

Rule 230.1 - Emission Reduction Credit Banking (March 11, 1992)

To qualify for banking the emissions reductions must comply with the requirements of subsection IV.A.2. The requirements of this subsection are summarized below:

1. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

2. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable.

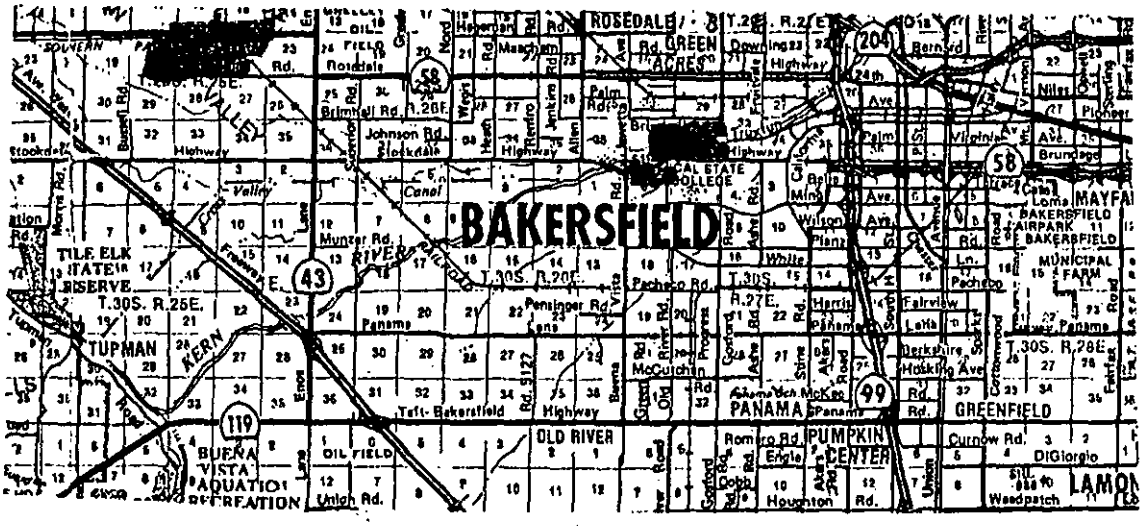
3. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

4. The reductions are included in or have been added to the 1987 emissions inventory.

5. The banking application must be filed within 180 days of the date of rule adoption.

III. LOCATION:

The carbon black facility was located 8 miles west of Bakersfield on Stockdale Highway Section 14, Township 32S, Range 23E. The Frito-Lay facility is located west of Bakersfield on highway 58 at Section 20, Township 29S, Range 25E. A map showing the relative locations of the facilities are shown on page 3. The use of these reductions as offsets at the Frito-Lay Snack Food Facility will be subject to the distance offset ratios required by the New Source Review Rule.



Location of reductions 20807 Stockdale Hwy

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IV. METHOD OF GENERATING REDUCTIONS:

The applicant has applied to bank reductions which were obtained from Continental Carbon generated by the shutdown of their carbon black manufacturing operation. Frito-Lay acquired the operating permits for the facility in order to provide offsets for their snack food manufacturing facility. These reductions occurred prior to adoption of a banking rule in Kern County. In order to maintain the emissions reductions for future use as offsets Frito-Lay has maintained permits on some of the carbon black manufacturing operation. Under the provisions of Rule 230.1 adopted September 19, 1991 in order to continue to maintain these reductions for use as offsets Frito-Lay must obtain ERC Banking Certificates. These reductions have previously been recognized and quantified by the following events:

Date	Summary
9/10/79	Continental Carbon (CC) Shutdown
7/1/82	Frito-Lay (dba The Food Company) Purchases CC PTOs
9/13/~~92~~ 82	Letter from TFC to KCAPCD Requesting Emissions Reductions be Established for Offsets
12/22/82	Letter from TFC to KCAPCD Requesting Emissions Revising 9/13/82 Request.
2/25/82	Letter from KCAPCD Recognizing Credits
4/25/83	KCAPCD Adopts Banking Rule
11/11/83	Frito-Lay Issued ATCs Using a Portion of Credits for Offsets
12/21/87	Letter from KCAPCD to Frito-Lay Describing Methods to Maintain Remaining Credits for Future Use
6/21/88	Letter from KCAPCD to Frito-Lay Recognizing Remaining Credits

The use of these credits by Frito-Lay has previously been reviewed by CARB and EPA.

PAGE NOT REVISED

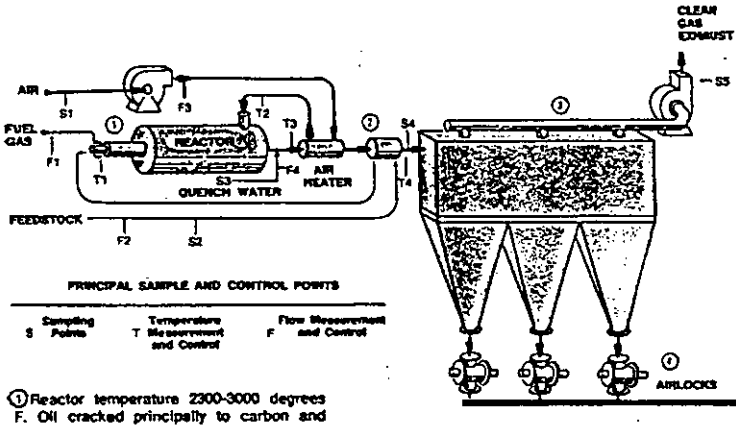
V. CALCULATIONS:

A. General

The carbon black facility was comprised of two independent carbon black production trains. Unit 1 produced a hard type or tread grade carbon black. Unit 2 produced a soft type or carcass grade carbon black. Both units used the oil furnace process for production of carbon black. Flow diagrams and a description of the process used is shown on page 5A .

Credits generated are associated with eight permits to operate for the carbon black facility the equipment associated with each permit is:

6026001	Unit 1 Reactors
6026002	Unit 1 Pulverizer/pelletizers
6026003	Unit 1 Dryer
6026004	Unit 1 Screens/separators/storage/bagging/loadout
6026005	Unit 2 Reactors
6026006	Unit 2 Pulverizer/pelletizers
6026007	Unit 2 Dryer
6026008	Unit 2 Screens/separators/storage/bagging/loadout



PRINCIPAL SAMPLE AND CONTROL POINTS

S Sampling Points	T Temperature Measurement and Control	F Flow Measurement and Control

① Reactor temperature 2300-3000 degrees F. Oil cracked principally to carbon and hydrogen.

② Carbon-laden gasses cooled by direct water sprays (to about 1000 degrees F.), further cooled by heat exchange with process air and feedstock.

③ Cooled reaction mixture (400-500 degrees F.) passes into silicone-coated glass fabric bags; closed end at top, open end inserted into cell plates at the floor.

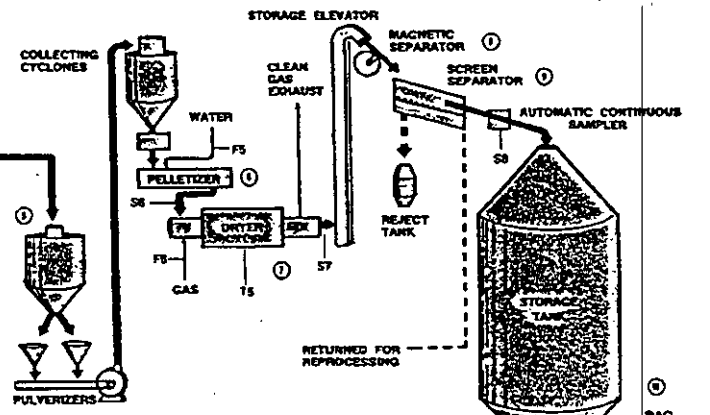
④ Outlet-header damper valves close at preset intervals (one filter at a time). Reverse flow of clean effluent gas forces collected carbon black to fall into hopper.

⑤ Pulverizers break up and disperse very small quantities of agglomerates if present.

⑥ Pulverized black (light, fluffy product with density about 3-4 lbs/ft³) conveyed to tubular mixing box for pelletizing. Water sprayed in, black and water whipped into small pellets by revolving pins.

⑩ Black packaging done by specially-designed air-flow valve packer developed by Continex engineers. Filling and weighing automatic, check weighed on second scale. Operator hand closes bag when weight exact.
From check weighing, bags automatically transferred to bag shaper, unitizing-glue applicator, and stacked on pallets.
Material being pulled into bags identified by production date marked on each pallet. Grade printed on bags.

Bulk storage uses different identification method since blending occurs during loading and unloading. Preshipment tests define and assure exact quality.

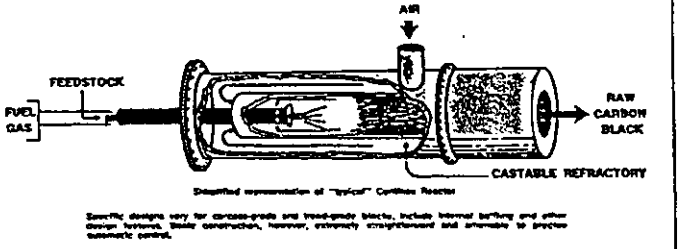


⑦ Pellets heated in dryer-drum to drive off moisture. Pelletized carbon (very low dust content) now ready for storage and final handling.

⑧ Magnetic separator eliminates any possible iron contamination.

⑨ In the screen separator large pellets are trapped by the top, coarse screen. Desired material is trapped by the middle, fine screen. Very fine material falls through both screens and is combined with the large material for reprocessing.

QUALITY "BUILT IN" AT HEART OF PROCESS — THE AUTOMATIC CONTINEX BLACK REACTOR



Simplified representation of "typical" Continex Reactor

Specific designs vary for carbon-grade and feed-grade blacks, include internal baffling and other design features. Basic construction, however, extremely straightforward and amenable to precise automatic control.

Consistent production of quality carbon black requires consistent reactor conditions — temperature, flow rates, and dimensions. Continex reactors are easily maintained to exact inside dimensions. Reaction tubes are easily changed when wear first occurs. The internal design may be altered quickly for rapid response to specific quality and product demands.

Continex-reactor design came from years of experimentation and pilot-plant testing. The critical reaction tubes are fabricated by lining pipe with high-grade castable alumina refractory. These tubes are the key to stable operations and are carefully made by the people responsible for their use.

continex ®

Continental Carbon Company
Witco Chemical Corporation

Continex, the long mileage carbon blacks.

Page 5A

PAGE NOT REVISED

V. CALCULATIONS:

B. PM-10, CO and VOC Emissions Reductions

Emission reductions previously recognized by the District of PM-10, CO and VOC are based on AP-42 Table 5.3-3 emission factors and actual carbon black production for the facility. These factors were adjusted to reflect recycle of main process vent gases installed at the facility in 1978. Source testing showed recirculation reduced emissions of CO and VOC by 29.5%. Carbon black production data for the baseline period is shown on page 7.

Emission factors used for PM10, CO and VOC are:

	Pounds/Ton Product		
	PM10	CO	VOC (non-methane)
Main process vent	6.53	2,800	100
Combined dryer vent	0.45	-	-
Pneumatic system vent	0.58	-	-
Oil storage tank vent	-	-	1.44
Vacuum clean-up system	0.06	-	-
Fugitive emissions	0.20	-	-
Total	7.82	2,800	101.44
Less 29.5% (no impact TSP)	-	826	29.92
Emission Factor	7.82	1,974	71.52

(Note: as the dryer vent at this facility was uncontrolled a factor of .45 was used)

Conversion of TSP to PM-10

As noted in AP-42 page 5.3-1 Carbon Black is "... extremely fine black fluffy particulate, 10 to 500 nm diameter. Therefore although the AP-42 factor is listed as TSP it can be concluded that all emissions of particulate matter from the carbon black production facility are also 10 microns or less. Thus the TSP emissions are 100% PM-10.

Average daily emissions over the baseline period are therefore:

	PM10	VOC	CO
Unit 1	279.4	2555.2	70,531.0
Unit 2	280.7	2221.4	61,317.2
Total	560.1	4776.6	131,848.2

PAGE NOT REVISED

V. CALCULATIONS CONT.:

Production Data:

Pounds/Year
Carbon Black

YEAR	Unit #1	Unit #2
1979	21,116,800	27,492,600
1978	20,848,100	24,922,400
1977	30,000,300	25,828,200
1976	18,703,000	21,786,500
1975	24,327,900	25,190,700
1974	32,349,100	26,538,000
1973	32,037,800	30,009,200
1972	29,294,000	27,865,100
Average (8 years)	26,084,625	26,204,087
Tons/Day (lbs/year/ 365x2000)	35.73	35.90

PAGE NOT REVISED

V. CALCULATIONS CONT.:

C. SO2 Emissions Reductions

The quantity of SO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility.

SOx specific limiting condition 198.9 lbs/hr x 24 hr/day

= 4,773.6 pounds/day

This previously recognized amount was compared to actual emissions over the baseline method using AP-42 emission factors and by a method (mass balance for sulfur in fuel, feedstock and carbon black) reported by I. Drogin in the Journal of the Air Pollution Control Association. These calculations of actual emissions (see pages _____) indicate actual emissions are equivalent to the specific limiting condition. Therefore the previously recognized SO2 emissions may be considered actual emissions reductions.

PAGE NOT REVISED

V. CALCULATIONS CONT.:

D. NO2 Emissions Reductions

The quantity of NO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. The specific limiting conditions for the permit are the maximum legal emission from an operation and therefore do not quantify real and actual emissions over the baseline period. To quantify actual emissions of NO2 source test data for the stationary source from November 1978 was used with the actual carbon black production over the baseline period. The source test data is summarized as follows:

Unit #	Stack #	Description	NO2 lb/hr	
1	1	Main Bagfilter	5.97	
1	2	Main Bagfilter	6.10	
1	3	Oil Preheater	1.30	
1	4	Firebox Stack	13.80	
1	5	Exhaust Bagfilter	1.79	Total Unit 1 28.96
2	6	Main Bagfilter	0.32	
2	7	Main Bagfilter	0.28	
2	8	Oil Preheater	0.72	
2	9	Firebox Stack	9.69	
2	10	Exhaust Bagfilter	2.53	Total Unit 2 13.53
		Boiler #1	not tested	
		Boiler #2	not tested	

V. CALCULATIONS CONT.:

Actual emissions over the baseline period are:

Basis:

Source test unit 1 NO2 emissions 28.96 lbs/hr
Source test unit 1 production rate 52.80* tons/day
Average unit 1 production rate 35.73 tons/day (see page 7)

Source test unit 2 NO2 emissions 13.53 lbs/hr
Source test unit 2 production rate 53.76* tons/day
Average unit 2 production rate 35.90 tons/day (see page 7)

Unit 1 Actual NO2 Emissions:

$$\frac{28.96 \text{ lb}}{\text{hr}} \mid \frac{24\text{hr}}{\text{day}} \mid \frac{35.73 \text{ tons/day average}}{52.80 \text{ tons/day test}} = 470.34 \text{ lbs/day}$$

Unit 2 Actual NO2 Emissions:

$$\frac{13.53 \text{ lb}}{\text{hr}} \mid \frac{24\text{hr}}{\text{day}} \mid \frac{35.90 \text{ tons/day average}}{53.76 \text{ tons/day test}} = 216.84 \text{ lbs/day}$$

Total NO2 Actual Emissions 470.34 + 216.84 = 687.2 lbs/day

* Revised per information submitted by applicant showing actual production rate see Appendix A

V. CALCULATIONS CONT.:

Actual emissions over the baseline period are:

Basis:

Source test unit 1 NO2 emissions 28.96 lbs/hr
Source test unit 1 production rate 6381.7 lbs/hr or 76.56 tons/day
Average unit 1 production rate 35.73 tons/day (see page _____)

Source test unit 2 NO2 emissions 13.53 lbs/hr
Source test unit 2 production rate 4887.6 lbs/hr or 58.56 tons/day
Average unit 2 production rate 35.90 tons/day (see page _____)

Unit 1 Actual NO2 Emissions:

28.96 lb / hr | 24hr / day | 35.73 tons/day average / 76.56 tons/day test = 324.37 lbs/day

Unit 2 Actual NO2 Emissions:

13.53 lb / hr | 24hr / day | 35.90 tons/day average / 58.56 tons/day test = 199.07 lbs/day

Total NO2 Actual Emissions 324.37 + 199.07 = 523.44 lbs/day

TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S})(64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /60	0 /4293
Dryer Vent	0.52/0	37.2/0
Boilers	142S (lbs/10^6 gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S)(0.50)(64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

Continental Carbon Company

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

10500 Richmond, P. O. Box 42817, Houston, Texas 77042. Telephone 713-978-5700 TWX 910-881-2636. Cable "CONCARB"

Page 10B

VI. COMPLIANCE:

A. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

The emission reductions were recognized in writing by the District in February 25, 1983. A copy of this correspondence is shown Appendix B. Kern County Air Pollution Control District Rule 210.3 - Emission Reductions Banking was adopted April 25, 1983 therefore, at the time the reductions were recognized the District did not have a banking rule. The reductions therefore satisfy the requirement that they were recognized in writing in a county that did not have a banking rule.

B. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable;

Actual Emissions Reductions

The Rule 230.1 definition of Actual Emissions Reductions states they are as defined in the District's New Source Review Rule. If the reductions are authorized by an Authority to Construct the adjustments made to the actual emissions reductions be as defined in the New and Modified Source Rule, shall be based on the rules, plans, workshop notices at the time the application for such Authority to Construct was deemed complete.

The Rule 220.1 definition of Actual Emissions Reductions states in part they are reductions of actual emissions from an emissions unit selected for emission offsets or banking, from the baseline period. Actual emission reductions shall be calculated pursuant to section V of this rule

The Rule 220.1 definition of Actual Emissions states they are measured or estimated emissions which most accurately represent the emissions from an emissions unit.

Rule 220.1 section V. - Calculations - states the following procedures shall be performed separately for each pollutant, and for each emissions unit or for a concurrent stationary source modification. All calculations shall be performed on a quarterly basis, unless specified otherwise.

For the shutdown of an emissions unit section V.E.2. of Rule 220.1 requires the actual emission reduction to be the Historic Actual Emissions prior to shutdown. Section V. also defines historic actual emissions as emissions having actually occurred based on source tests or calculated using actual fuel consumption or process weight, recognized emissions factors or other data approved by the Control Officer which most accurately represent the emissions during the baseline period.

VI. COMPLIANCE:

The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.

The baseline period used in the original quantification of the emissions reductions was the eight year period 1972-1979. The use of this baseline period is not prohibited by Rules 220.1 and 230.1. These reductions were calculated on an annual daily basis. Because this type of source is not subject to seasonal variations emissions can be expected to be evenly distributed over the year. Thus the reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1:

	Daily Emissions	Reference Page
PM10	560.1	8
SO2	2,768.3	22
NO2	687.2	26
VOC	4,776.6	8
CO	131,848.2	8

	Quarterly Emissions			
	First	Second	Third	Fourth
Days/Qtr	90	91	92	92
PM10	50,409	50,969	51,529	51,529
SO2	249,147	251,915	254,684	254,684
NO2	61,848	62,535	63,222	63,222
VOC	429,894	434,671	439,447	439,447
CO	11,866,338	11,998,186	12,130,034	12,130,034

As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.

~~VI. COMPLIANCE:~~

~~The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.~~

~~The baseline period used in the original quantification of the emissions reductions was the eight year period 1972-1979. The use of this baseline period is not prohibited by Rules 220.1 and 230.1. These reductions were calculated on an annual daily basis. Because this type of source is not subject to seasonal variations emissions can be expected to be evenly distributed over the year. Thus the reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1:~~

	~~Daily Emissions~~	~~Reference Page~~
~~PM10~~	~~560.1~~	~~8~~
~~SO2~~	~~2,768.3~~	~~22~~
~~NO2~~	~~523.4~~	~~26~~
~~VOC~~	~~4,776.6~~	~~8~~
~~CO~~	~~131,848.2~~	~~8~~

~~Quarterly Emissions~~

	~~First~~	~~Second~~	~~Third~~	~~Fourth~~
~~Days/Qtr~~	~~90~~	~~91~~	~~92~~	~~92~~
~~PM10~~	~~50,409~~	~~50,969~~	~~51,529~~	~~51,529~~
~~SO2~~	~~249,147~~	~~251,915~~	~~254,684~~	~~254,684~~
~~NO2~~	~~47,106~~	~~47,629~~	~~48,153~~	~~48,153~~
~~VOC~~	~~429,894~~	~~434,671~~	~~439,447~~	~~439,447~~
~~CO~~	~~11,866,338~~	~~11,998,186~~	~~12,130,034~~	~~12,130,034~~

~~As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.~~

VI. COMPLIANCE:

Real

The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. The reductions therefore represent real emissions.

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:

	Pounds/Day				
	PM10	SO2	NO2	VOC	CO
Actual Reductions	560.1	4773.6	687.2	4776.6	131,848.2
Used for Snack Food Facility Offsets	282.5	303.0	479.4	-	-
Donated to District	-	2673.9	-	2221.4	130,848.2
Balance Surplus Reductions	277.5	1796.7	207.8	2555.2	1,000.0

Permanent

All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.

Quantifiable

Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The reductions therefore are quantifiable.

~~VI. COMPLIANCE:~~

~~Real~~

~~The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. The reductions therefore represent real emissions.~~

~~Surplus~~

~~The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:~~

	Pounds/Day				
	PM10	SO2	NO2	VOC	CO
Actual Reductions	560.1	4773.6	523.4	4776.6	131,848.2
Used for Snack Food Facility Offsets	282.5	303.0	479.4	-	-
Donated to District	-	2673.9	-	2221.4	130,848.2
Balance Surplus Reductions	277.5	1796.7	44.0	2555.2	1,000.0

~~Permanent~~

~~All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.~~

~~Quantifiable~~

~~Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The reductions therefore are quantifiable.~~

PAGE NOT REVISED

VI. COMPLIANCE:

Enforceable

The permits to operate for the carbon black facility will be surrendered any new construction or operation of existing equipment at the site will require Authority to Construct pursuant to Rule 2010 and will be subject to new source review prior to construction or operation. The reductions are therefore enforceable.

C. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting remaining (surplus) emissions reductions are shown on page 13.

D. The reductions are included in or have been added to the 1987 emissions inventory.

Upon original approval of these emissions reductions the District required that these emissions be included in the current NAP inventory. To insure the proper amount of emissions is included District planning staff will be informed whenever all or a portion of these emissions are used as offsets for the Frito-Lay facility.

E. The banking application must be filed within 180 days of the date of rule adoption.

The application for emission reduction banking credits was submitted to the District March 17, 1992. This is within 180 days September 19, 1991 the date of rule adoption.

F. Because these emission reductions can be validated as Actual Emission Reductions they qualify for ERC banking certificates that may be used in accordance with the requirements of Rule 220.1.

VII. **RECOMMENDATION:**

Issue ERC banking certificated to Frito-Lay, ~~subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito-Lay snack foods processing plant at their present site and may not be sold or traded.~~

After public notice and review issue ERC Banking Certificates in the following amounts:

Pounds/Day From Page 13

PM10	SO2	NO2	VOC	CO
277.5	1796.7	207.8	2555.2	1000

Pounds/Quarter

	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	18,702	229,968	90,000
2nd Qt	25,252	163,500	18,910	232,523	91,000
3rd Qt	25,530	165,296	19,118	235,078	92,000
4th Qt	25,530	165,296	19,118	235,078	92,000

~~VII. RECOMMENDATION:~~

~~Issue ERC banking certificated to Frito-Lay subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito-Lay snack foods processing plant at their present site and may not be sold or traded.~~

~~After public notice and review issue ERC Banking Certificates in the following amounts:~~

~~Pounds/Day From Page _____~~

~~PM10~~	~~SO2~~	~~NO2~~	~~VOC~~	~~CO~~
~~277.5~~	~~1796.7~~	~~44.0~~	~~2555.2~~	~~1000~~

~~Pounds/Quarter~~

	~~PM10~~	~~SO2~~	~~NO2~~	~~VOC~~	~~CO~~
~~1st Qt~~	~~24,975~~	~~161,703~~	~~3,960~~	~~229,968~~	~~90,000~~
~~2nd Qt~~	~~25,252~~	~~163,500~~	~~4,004~~	~~232,523~~	~~91,000~~
~~3rd Qt~~	~~25,530~~	~~165,296~~	~~4,048~~	~~235,078~~	~~92,000~~
~~4th Qt~~	~~25,530~~	~~165,296~~	~~4,048~~	~~235,078~~	~~92,000~~

APPENDIX A

PRODUCTION DATA DURING SOURCE TEST

OBJECTIVE: **DETERMINE CARBON BLACK PRODUCTION RATE FOR UNIT #1 DURING 11/78 STACK TEST**

INPUTS:

- Tests were conducted on 11/2, 11/5 and 11/6/78.
- Unit #1 was producing N339 grade carbon black during test period. For N339, 4.365 lbs carbon black are produced for every gallon of feedstock charged to the reactors.
- The following feedstock charge oil rates were recorded by Agency representatives. These rates represent the total charged to Reactors #1, 3, 4 & 5.

DATE	TIME	FEEDSTOCK CHARGE RATE (gph)
11/2/78	0925	1030
11/2/78	1037	1031
11/2/78	1325	1030
11/6/78	1020	1012
11/6/78	1056	1006
11/6/78	1107	1008
11/6/78	1200	1004
11/6/78	1230	1007
11/6/78	1300	1000
11/6/78	1525	984
11/6/78	1542	984
	AVG.	1008

See sample of original records

RECEIVED
OCT 29 1992
SAN JOAQUIN VALLEY UNIFIED APCD—SOUTHERN REGION

ANALYSIS

(4.365 lbs carbon black/gal feedstock)(1008 gph feedstock) = 4399.9 lbs/hr or 2.2 TPH

(2.2 TPH) (24 hrs/day) = 52.80 TPD carbon black production (Unit #1)

CONCLUSION

Unit #1 Reactors were producing an average of 52.80 TPD of N339 grade carbon black during the November, 1978 test period. This is approximately 70% of the maximum production capacity for Unit #1 (6381.7 lbs/hr or 76.56 TPD).

OBJECTIVE: **DETERMINE CARBON BLACK PRODUCTION RATE FOR UNIT #2 DURING 11/78 STACK TEST**

INPUTS:

- Tests were conducted on November 14--17, 1978.
- N660 was the carbon black grade being produced. N660 is produced at a rate of 5.622 lbs/gal feedstock charged to the reactor(Unit #2 had only one operating reactor, designated as reactor #2).
- The following feedstock charge oil rates were recorded by Agency representatives.

DATE	TIME	FEEDSTOCK CHARGE RATE (gph)
11/14/78	Avg.	777
11/15/78	Avg.	783
11/16/78	Avg.	810
11/17/78	Avg.	819
	AVG.	797

ANALYSIS

(5.622 lbs carbon black/gal feedstock) (797 gph feedstock) = 4480.7 lbs/hr or 2.24 TPH

(2.24 TPH) (24 hrs/day) = 53.76 TPD carbon black production (Unit #2)

CONCLUSION

Unit #2 reactor was producing an average of 53.76 TPD of N660 grade carbon black during the November, 1978 test period. This is approximately 90% of the maximum production capacity for Unit #2 (4887.6 lbs/hr or 58.56 TPD).

CONTINENTAL CARBON CO.

PRODUCT N339

11-2-78

By T. COFF

w/ McDONALD, COOK

ne 9:25

FACTOR	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR ×1200 = scfh
1	220 gal/hr	6 ≈ 10,000 scf/hr	6.95 ≈ 147,000 scf/hr	14 = 1680 scf
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH
1		990°F		660°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
2	273 gal/hr		6.95 ≈ 147,000 scf/hr	6. 7320 scf/
	FUEL OIL	REACTOR QUENCH T.	AIR PREHEAT T	DUCT QUENCH
3	69.5 gal/hr	900°F		660°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
4	285 gal/hr		7.0 ≈ 148,000 scf/hr	5.65 = 6780 s
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH T
4	69.5 gal/hr	885°F		675°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
5	252 gal/hr		7.0 ≈ 150,000 scf/hr	7.15 = [illegible]
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH
5	6[illegible] gal/hr	885°F		645°F

	RATIO (blower)	COMBUSTION AIR (RED)	WASTE GAS (GREEN)	TEM
HEATER	0.58	4.1 = 1640 scf/hr	4.4 = ~~39,650 scf/hr~~ 44,000 scf/hr	

2 Dev #1

Total Charge Oil

1030 gph

2 Dev #2

Page 19 M7407

Total Chg Rate 1030

" Fuel Oil Rate 206

Exhibit D

RESOURCE MANAGEMENT AGENCY

RANDALL L. ABBOTT
DIRECTOR

DAVID PRICE III
ASSISTANT DIRECTOR

Air Pollution Control District
WILLIAM J. RODDY, APCO

Environmental Health Services Department
STEVE McCALLEY, REHS, DIRECTOR

Planning & Development Services Department
TED JAMES, AICP, DIRECTOR

July 24, 1991

MR. DAVID C. HOWEKAMP, Director
Air and Toxics Division
Environmental Protection Agency, Region IX
75 Hawthorne Street
San Francisco, California 94105

Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay

Dear Mr. Howekamp:

On November 11, 1983, the Kern County Air Pollution Control District issued Authorities to Construct (ATC's) to Frito-Lay, Inc., for the first phase of a salty snack food production facility (EPA approval NSS 4-3). Offsets used to mitigate the air quality impact of the new equipment were provided by the December 1981 shutdown of the Continental Carbon Black production stationary source located approximately six miles from the Frito-Lay facility. As you will recall, EPA agreed to use of these reductions as offsets for Frito-Lay's planned snack foods production facilities. In accordance with a letter dated April 10, 1984, from EPA to Dr. Leon Hebertson, Air Pollution Control Officer, Kern County Air Pollution Control District, EPA permitted use of the Continental Carbon Company offsets for the Frito-Lay project, including expansion of the project consistent with the original project environmental impact report. Frito-Lay has maintained Permits to Operate carbon black manufacturing equipment (with emissions limitations reduced by the amounts of consumed offsets) since acquiring ownership of the Permits in September 1983.

Frito-Lay recently indicated they now wish to seek approval for additional snack food lines consistent with the original project description. Frito-Lay intends to utilize the remaining emissions represented by the Continental Carbon Permits to Operate inorder to offset expected emissions increases.

2700 "M" STREET, SUITE 350 BAKERSFIELD, CALIFORNIA 93301 (805) 861-350
FAX: (805) 861-342

PRINTED ON RECYCLED PAPER

The San Joaquin Valley Unified Air Pollution Control District intends to comply with previous EPA and Kern Air Pollution Control District commitments by permitting the use of Continental Carbon Company offsets for the new snack food lines. If you disagree with this determination, please advise me prior to Monday, August 5, 1991.

If you desire additional information, please telephone me at (805) 861-3502.

Very truly yours,

RANDALL L. ABBOTT, Director
Resource Management Agency

RLA:rrk

Enclosure

Exhibit E

THE FOOD COMPANY

9226 South Vermont Avenue
Los Angeles, California 90044

September 13, 1982

Mr. Tom Paxson
Air Sanitation Engineer IV
Kern County Air Pollution Control District
1601 H Street, Suite 250
Bakersfield, California 93301

Dear Mr. Paxson:

Per our discussion of September 2, 1982, please find the enclosed attachment regarding Continental Carbon's Bakersfield facility emissions and establishment of corresponding emission reduction credits for use by the Food Company (TCFC, Inc.). In summary these are:

	lbs/day
Particulate	559.49
Carbon Monoxide	141,239.70
Hydrocarbons	5,117.26
Hydrogen Sulfide	3,026.60
Sulfur Dioxide	4,773.60
Nitrogen Oxides	1,059.36

As previously indicated, we are eager to submit a preliminary "Application to Construct" for our proposed Kern County Facility. Submittal of this preliminary document will occur following endorsement by our management of Kern County as a plant setting and the optioning of specific sites.

We are appropriately interested in reviewing the proposed Kern County Banking Rule and would welcome the opportunity to participate as a non-oil producer in its development.

I will be contacting you in the near future to schedule a time to review our draft permit application. If you should have any questions regarding the enclosure or otherwise, please advise.

Sincerely,

THE FOOD COMPANY (TCFC, INC.)

HC Bradbury

H.C. Bradbury
Group Manager, Environmental Compliance

BCC:
PF# A-1 Sam Frenk
Trudy Wright Liza Urso

cc: Howard Franck, General Counsel
Continental Carbon, Inc.

0904S/HCB/sb

CONTINENTAL CARBON EMISSION CREDITS

I. Carbon Black Production (avg. of yrs. '72 through '79): 52,288,712 lbs/yr
(See Attachment 1)

$$\frac{52,228,712 \text{ lbs/yr}}{2000 \text{ lbs/ton } (365 \text{ days/yr})} = 71.55 \text{ ton/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP42 emission factors for Carbon Black Manufacture (B Oil furnace process), 7/79.

PROCESS	EMISSION FACTORS (lbs/ton of Product)			
	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Main Process Vent	6.53	2,800	100	60
Dryer Vent Uncontrolled (Firebox)	.45	---	---	---
Pneumatic System Vent Bag Filter	.58	---	---	---
Oil Storage Tank Vent	---	---	1.44	---
Vacuum Cleanup System Vent	.06	---	---	---
Fugitive Emissions	.20	---	---	---
SOURCE TOTAL	7.82	2,800	101.44	60
Less 29.5% for Modification in 1978 does not impact TSP.	---	826	29.92	17.70
Emission Factor Total	7.82	1,974	71.52	42.30
III. Total Emissions Credit in lbs/day of Pollutant (Factor x ton. Finished Product/Day)	559.49	141,239.70	5,117.26	3,026.60

Emission credits for SO_2 and NO_x are based on the "Specific Limiting Conditions" identified in Continental Carbons Permit to Operate, as outlined by Kern County APCP Rule 210.1.

SO_2 Specific Limiting Condition is 198.9 lbm/hr
198.9 lb/hr (24 hrs/day) = 4,773.60 lbs/day

NO_x Specific Limiting Condition is 44.14 lbm/hr
44.14 lb/hr (24 hrs/day) = 1,059.36 lbs/day

0904S/HCB/sb

Exhibit F

RULE 210.1 Amended 9/12/79

State of California
AIR RESOURCES BOARD
Attachment A to Resolution 79-68
Adopted: September 12, 1979

Kern County
NEW SOURCE REVIEW RULES

RULE 210.1 Standard for Authority to Construct:

1. Definitions

A. Best Available Control Technology (BACT) means for any stationary source or modification the technology which gives the maximum degree of reduction of each air contaminant emitted from or resulting from such class or category of source which the Control Officer determines is achievable for such source. The Control Officer shall make this determination on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs. The Control Officer shall consider production processes and available methods, systems, and techniques for control of each such air contaminant, including fuel cleaning or treatment or innovative fuel combustion techniques.

In no event shall the emission rate reflected by the control technique or limitation exceed the amount allowable under applicable new source performance standards.

B. Lowest Achievable Emission Rate (LAER) means for any stationary source or modification the more stringent of:

1. The most effective emissions control technique which has been achieved in practice, for such class or category of source; or

2. The most effective emission limitation which the Federal Environmental Protection Agency certifies is contained in the implementation plan of any State approved under the Clean Air Act for such class or category of source, unless the owner or operator, of the proposed source demonstrates that such limitations are not achievable; or

3. The emission limitation specified for such class or category of source under applicable Federal new source performance standards pursuant to Section 111 of the Clean Air Act; or

4. Any other emissions control technique found, after public hearing, by the Control Officer or the Air Resources Board to be technologically feasible and cost effective for such class or category of sources or for a specific source.

C. Modeling means using an air quality simulation model, based on specified assumptions and data which has been approved in writing by the Executive Officer of the Air Resources Board.

D. Modification means any physical change in, change in method of operation of, or addition to an existing stationary source, except that routine maintenance or repair shall not be considered to be a physical change. A change in the method of operation, unless previously limited by an enforceable permit condition, shall not include:

1. An increase in the production rate, if such increase does not exceed the operating design capacity of the source.

2. An increase in the hours of operation.

3. Change in ownership of a source.

4. Any part or item of equipment used to replace an existing part or item of equipment, on the same property, which has failed, provided the applicant certifies in writing to the Control Officer that the replacement component is identical in all material respects to the component replaced and that the replacement will not result in an increase in emissions.

E. Precursor means a directly emitted air contaminant that, when released to the atmosphere, forms or causes to be formed or contributes to the formation of a secondary pollutant for which a national ambient air quality standard has been adopted or whose presence in the atmosphere will contribute to the violation of one or more national ambient air quality standard. The following precursor-secondary air contaminant relationships shall be used for the purposes of this rule.

PRECURSOR	SECONDARY AIR CONTAMINANT
Hydrocarbons and substituted hydrocarbons (Reactive organic gases)	a. Photochemical Oxidants (Ozone) b. The organic fraction of suspended particulate matter.
Nitrogen Oxides	a. Nitrogen dioxide b. The nitrate fraction of suspended particulate matter. c. Photochemical oxidant (ozone).
Sulfur Oxides	a. Sulfur dioxide b. Sulfates c. The sulfate fraction of suspended particulate matter.

F. Seasonal Source means any stationary source with more than 75 percent of its annual operating hours within a consecutive 90-day period.

G. Stationary Source includes any structure, building, facility, equipment, installation or operation (or aggregation thereof) which is owned, operated, or under shared entitlement to be used by the same person and which is located within the District on:

1. One property or on bordering properties; or

2. One or more properties wholly within either the Western Kern County Oil Fields or the Central Kern County Oil Fields and is used for the production of oil.

Items of air-contaminant-emitting equipment shall be considered aggregated into the same stationary source, and items of nonair-contaminant-emitting equipment shall be considered associated with air-contaminant emitting equipment only if:

1. The operation of each item of equipment is dependent upon, or affects the process of, the others; and

2. The operation of all such items of equipment involves a common raw material or product.

Emissions from all such aggregated items of air-contaminant-emitting equipment and all such associated items of nonair-contaminant-emitting equipment of a stationary source shall be considered emissions of the same stationary source.

H. Upwind area shall be bounded by a line drawn perpendicular to the predominant wind flow line passing through or nearest to the site of the new source or modification and extending to the boundaries of the same or adjoining counties within the same air basin except where the Control Officer determines that for reasons of topography or meteorology such a definition is inappropriate. The predominant wind flow lines used in this rule shall be those contained in Figure I. For sites located between diverging and converging wind flow lines, an interpolated line shall be constructed which bisects the distance between the applicable flow lines shown in Figure I.

I. Major Stationary Source is a stationary source which emits 200 pounds or more during any day of any air contaminant for which there is a national ambient air quality standard or any precursor of such contaminant.

J. National Ambient Air Quality Standard: All references in Rule 210.1 and 210.2 to national ambient air quality standards shall be interpreted to include state ambient air quality standards. (This subsection shall not be submitted or is it intended to be a part of the State Implementation Plan.)

K. Point of maximum ground level impact means that area where the actual or projected air contaminant concentrations resulting from the new or modified stationary source are at the maximum level after including the effect of any control technology and mitigation employed.

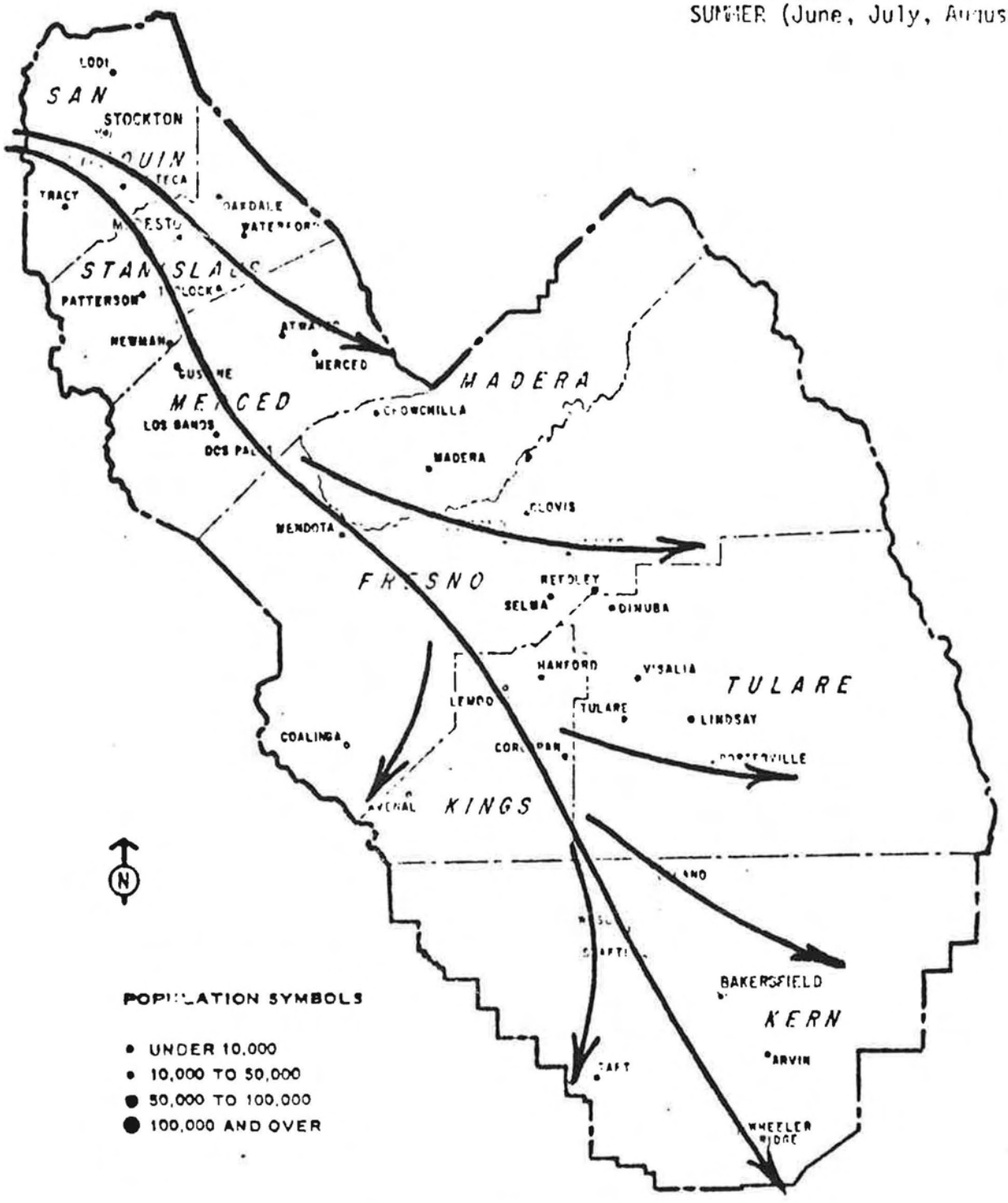
L. Central Kern County Fields boundaries are described as:

Beginning at a point common to the northerly boundary line of Kern County and the line bearing in a southerly direction between Range 24E and Range 25E, MDB&M; thence south along said line between Range 24E and Range 25E to a point on the line between Township 28S and Township 29S, MDB&M; thence west along said line between Township 28S and Township 29S to a point on the line bearing in a southerly direction between Range 24E and Range 25E, MDB&M; thence

SAN JOAQUIN VALLEY AIR BASIN

Figure I

PREDOMINANT WIND FLOW
SUMMER (June, July, August)



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south along said line between Range 24E and Range 25E to a point on the line between Township 32S, MDB&M, and Township 12N, SBB&M; thence east along said line between Township 32S and Township 12N to a point on the line between Range 22W and Range 23W, SBB&M, thence south along said line to a point on the line between Township 10N and Township 11N, SBB&M; thence east along said line between Township 10N and Township 11N to a point on the line between Range 20W and Range 21W, SBB&M; thence south along said line between Range 20W and Range 21W to a point on the line bearing in an easterly direction between Township 10N and Township 11N, SBB&M; thence east on said line between Township 10N and Township 11N to a point on the line between Range 17W and Range 18W, SBB&M; thence north along said line between Range 17W and Range 18W to a point on the line between Township 32S, MDB&M, and Township 12, SBB&M; thence east along said line between Township 32S and Township 12N to a point on the line between Range 30E and Range 31E, MDB&M; thence north along said line between Range 30E and Range 31E to a point on the line between Township 28S and Township 29S, MDB&M; thence east along said line between Township 28S and Township 29S to a point on the line bearing in a northly direction between Range 30E and Range 31E, MDB&M; thence north along said line between Range 30E and Range 31E to a point on the northerly boundary line of Kern County; thence west along said boundary to the point of beginning. (Figure 2)

M. Western Kern County Fields boundaries are described as:

Beginning at a point common to the northerly boundary of Kern County and the line between Range 24E and 25E, MDB&M, and following the Kern County boundary in a westerly, then a southerly, and then easterly and southerly directions to a point common to the easterly County boundary and the line between Township 10N and Township 11N, SBB&M; thence easterly along said line between Township 10N and Township 11N to a point on the line between Range 22W and Range 23W, SBB&M; thence north along said line between Range 22W and Range 23W to a point on the line between Township 32S, MDB&M, and Township 12N, SBB&M; thence westerly along said line between Township 32S and Township 12N to a point on the line between Range 24E and Range 25E, MDB&M; thence north on said line between Range 24E and 25E to a point on the line between Township 28S and Township 29S, MDB&M; thence east along said line between Townships 28S and 29S to the point on the line bearing in a northerly direction between Range 24E and Range 25E, MDB&M; thence north along said line between Range 24E and 25E to the point of beginning. (Figure 3)

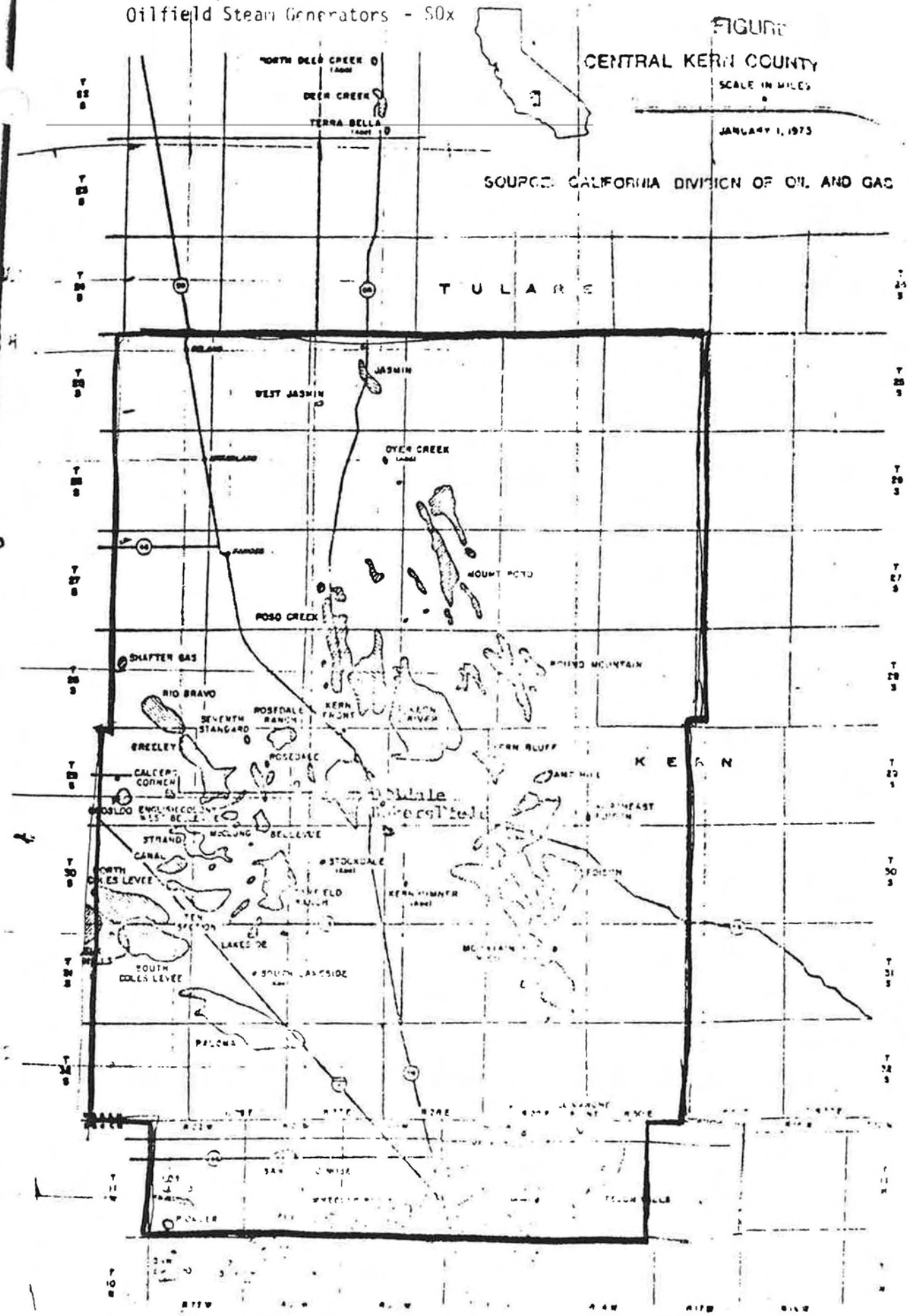
2. General

A. The Control Officer shall deny an Authority to Construct for any new stationary source or modification, or any portion thereof unless:

1. The new source or modification, or applicable portion thereof, complies with the provisions of this rule and all other applicable District rules and regulations; and

Oilfield Steam Generators - SOx

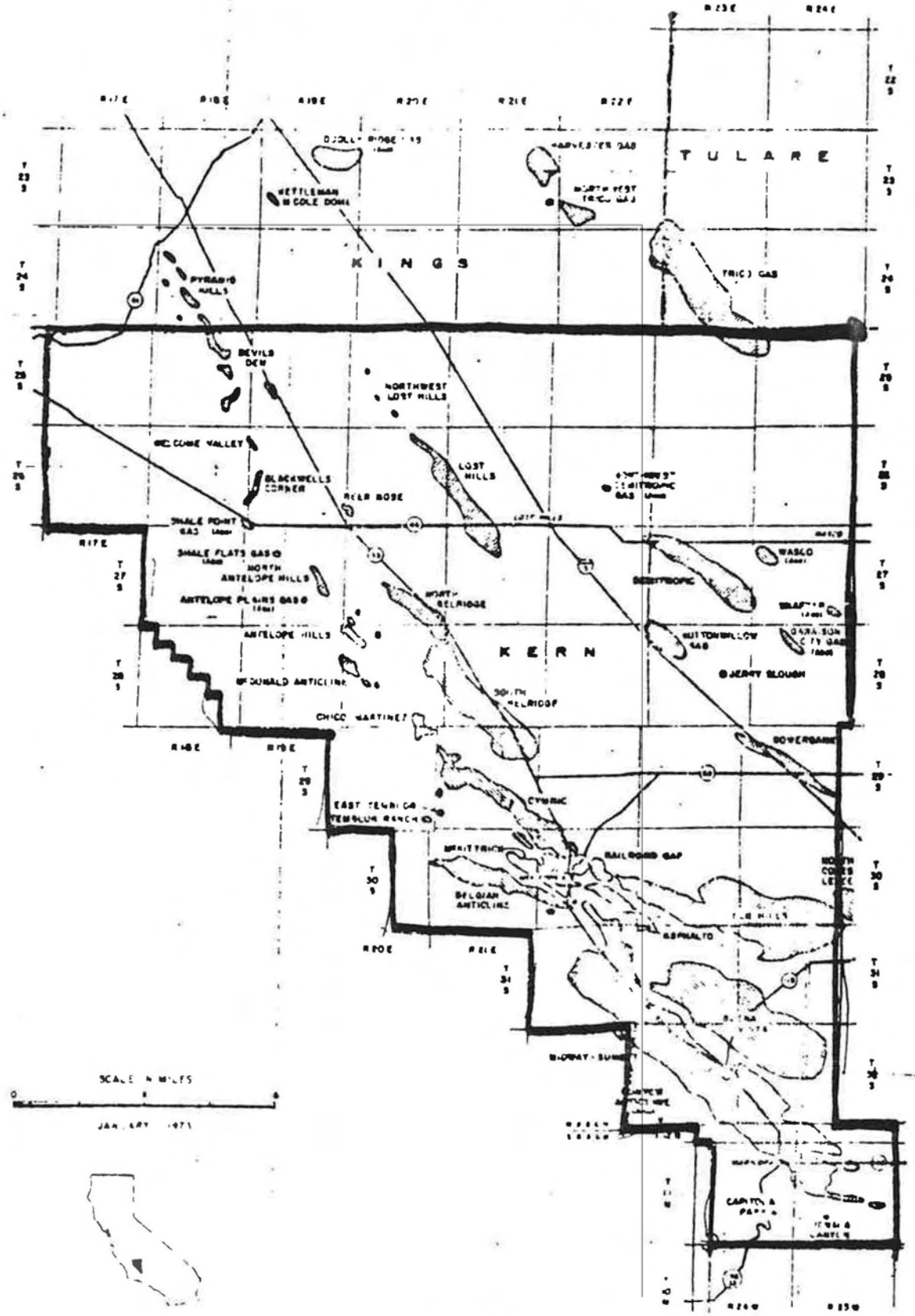
FIGURE



39.4
39.5.2
39.2.5
39.1.4
39.0.4
38.9.2
38

41.0 39.5 36.1 31.6 32.2 33.7 35.0 36.3

WESTERN KERN COUNTY OIL FIELDS with UTM COORDINATES



SOURCE: CALIFORNIA DIVISION OF OIL AND GAS

M-421

for all pollutants for which there is a national ambient air quality standard and all precursors of such pollutants. All sources applying for an Authority to Construct pursuant to this section shall be shown not to significantly impact Class I areas as specified in Part C of the Clean Air Act.

E. Notwithstanding the provisions of Section (3)(C), the Control Officer may exempt from Section (5)(B) any new source or modification:

1. Which will be used exclusively for providing essential public services, such as schools, hospitals, or police and fire fighting facilities, but specifically excluding sources of electrical power generation other than for emergency standby use at essential public service facilities.

2. Which is exclusively a modification to convert from use of a gaseous fuel to a liquid fuel because of a demonstrable shortage of gaseous fuels, provided the applicant establishes to the satisfaction of the Control Officer that it has made its best efforts to obtain sufficient emissions offsets pursuant to Section (5) of this rule, that such efforts had been unsuccessful as of the date the application was filed, and the applicant agrees to continue to seek the necessary emissions offsets until construction on the new stationary source or modification begins. This exemption shall only apply if, at the time the Permit to Operate was issued for the gas burning equipment, such equipment could have burned the liquid fuel without additional controls and been in compliance with all applicable district regulations.

3. Which is portable sandblasting equipment used on a temporary basis within the District.

4. Which uses innovative control equipment or processes which will likely result in a significantly lower emission rate from the stationary source than would have occurred with the use of previously recognized LAER, and which can be expected to serve as a model for technology to be applied to similar stationary sources within the state resulting in a substantial air quality benefit, provided the applicant establishes by modeling that the new stationary source or modification will not cause the violation of any national ambient air quality standard at the point of maximum ground level impact. This exemption shall apply only to air contaminants which are controlled by the innovative control equipment or processes. The Control Officer shall consult with the Executive Officer of the Air Resources Board prior to granting an exemption pursuant to this subsection.

5. Which consists solely of the installation of air pollution control equipment which, when in operation, will directly control emissions from an existing source.

2. For a major stationary source, the applicant certifies that all major stationary sources in the State that are owned or operated by the applicant are in compliance, or are on approved schedule for compliance, with all applicable emission limitations and standards under the Clean Air Act (42 USC 7401 et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency.

B. The Control Officer may issue an Authority to Construct for a new stationary source or modification which is subject to Section (5) only if all District regulations contained in the State Implementation Plan approved by the EPA are being carried out in accordance with that plan.

3. Applicability and Exemptions

A. This rule, excluding Section 5, shall apply to all new or modified stationary sources which are required pursuant to District rules to obtain an Authority to Construct.

This rule shall be effective September 12, 1979, and shall apply to all applications for Authority to Construct which are received after September 12, 1979, or which are pending on its adoption. However all applications reviewed under Rule 210.1, as adopted 12/28/76, and which prior to September 12, 1979, received a preliminary decision pursuant to Section (h) of that rule, shall not be subject to this provision.

B. Section 5A of this Rule shall apply to all new stationary sources or modifications which are to result in a net increase in emissions of 150 lbs or more during any day of any air contaminant for which there is a national ambient air quality standard (excluding carbon monoxide) or any precursor of such contaminant.

C. Sections 5B of this Rule shall apply to all new stationary sources or modifications which will result in either:

1. A net increase in emissions of 200 lbs or more during any day of any air contaminant for which there is a national ambient air quality standard (excluding carbon monoxide) or any precursor of such a contaminant; or

2. A net increase in carbon monoxide emissions which the Control Officer determines would cause the violation of any national ambient air quality standard for carbon monoxide at the point of maximum ground level impact.

D. The provisions of Part C of the Clean Air Act, as amended in 1977, and any regulations adopted pursuant to those provisions, shall not be applicable to any new stationary source or modification which receives and Authority to Construct pursuant to this rule, provided such source or modification complies with the requirements of Section (5)(B)(2)

6. Which wishes to construct in an area which has a lack of major industrial development or absence of significant industrial particulate emissions and low urbanized population as long as the source can comply with the BACT and applicable federal, state and District emission regulations; and the impact of the emissions plus emissions from other stationary sources in the vicinity of the proposed location, along with non-rural fugitive background, will not cause a violation of the national ambient air quality standards. This exemption shall apply only to particulate emissions.

F. This rule shall not apply to any air pollution control equipment for a specific pollutant, which when in operation, will reduce air contaminant emissions from the source operation provided that equipment does not increase emissions of another pollutant.

4. Calculation of Emissions

A. The maximum design capacity of a new stationary source or modification shall be used to determine the emissions from the new source or modification unless the applicant, as a condition to receiving Authorities to Construct and Permits to Operate such new source or modification, agrees to limitations on the operations of the new source or modification, in which event the limitations shall be used to establish the emissions from the new source or modification.

B. The emissions from an existing source shall be based on the specific limiting conditions set forth in the source's Authorities to Construct and Permits to Operate, and, where no such conditions are specified, or where no Authority to Construct is required, on the actual operating conditions of the existing source averaged over the three consecutive years immediately preceding the date of application, or such shorter period as may be applicable in cases where the existing source has not been in operation for three consecutive years, or is cyclic in nature. Where the operation of a specific source has been significantly reduced during the previous three years, the Air Pollution Control Officer may specify an averaging period or emission rate which he determines provides an equitable emission base. If violations of laws, rules, regulations, permit conditions, or orders of the District, the California Air Resources Board, or the Federal Environmental Protection Agency occurred during the period used to determine the operating conditions, then adjustments to the operating conditions shall be made to determine the emissions the existing source would have caused without such violations.

C. The net increase in emissions from new stationary sources and modifications which are not seasonal sources shall be determined using yearly emission profiles or equivalent method (as specified by the Control Officer) subject to consultation with the ARB Executive Officer. Yearly emissions profiles for an existing or proposed stationary source or modification shall be constructed by plotting the daily emissions from such source in descending order. A separate profile shall be constructed for each

pollutant. The net increase in emissions from a modification to an existing source shall be determined by comparing the yearly emissions profiles for the existing source to the yearly emissions profiles for the proposed source after modification. A net increase in emissions exists whenever any part of an emissions profile for a modified source exceeds the emissions profile for the existing source.

D. The net increase in emissions from new stationary sources and modification which are seasonal sources shall be determined using yearly and quarterly emissions profiles, or equivalent method as specified by the Air Pollution Control Officer, subject to consultation with the ARB Executive Officer. Quarterly emissions profiles shall be constructed by plotting the daily emissions from an existing or proposed seasonal facility in descending order for the continuous 90 day period during which the greatest emissions from the proposed new or modified source will occur. A separate profile shall be constructed for each pollutant. The net increase in emissions from the modification to an existing seasonal source shall be determined by comparing the yearly and quarterly emissions profiles for the existing source to the yearly and quarterly emissions profiles for the proposed source after modification. A net increase in emissions exists whenever any part of an emissions profile for the modified source exceeds the emissions profile for the existing source.

E. When computing the net increase in emissions for modifications, other th modifications to heavy oil production operations, the Control Officer sh take into account the cumulative net emissions changes which were achiev after December 28, 1976, and which are represented by Authority to Const or Permit to Operate issued to the stationary source excluding any emiss reductions required to comply with any federal, state or district law, r order or regulation. When computing the net increase in emissions for modifications to heavy oil production operations, the Control Officer shall take into account the cumulative net emissions changes represented by Authority to Construct issued to the stationary source after Septemb 12, 1979, excluding any emissions reduction required to comply with any federal, state, or district law, rule, order, or regulations, except Rule 425. Emissions resulting from implementation of Rule 425 shall be taken into account in accordance with the requirements of Rule 425.

Added 3/6/80 by CARB

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5. Control Technology and Mitigation Requirements

A. Best Available Control Technology (BACT)

All new stationary sources and modifications subject to this section shall be constructed using BACT for such net air contaminant increases as specified in Section 3.B.

B. Lowest Achievable Emission Rate (LAER) and Mitigation

1. All new stationary sources and modifications subject to this section shall be constructed using LAER, and mitigation shall be required for such net emission increases (i.e. increases after the application of LAER) as specified in Section 3.C.

a. of such air contaminant(s) for which a national ambient air quality standard was exceeded within the air basin more than three discontinuous times within the three years immediately preceding the date when the application for the Authority to Construct was filed, and for all precursors of such air contaminants; provided, however, that mitigation of net emission increases of sulfur oxides, total suspended particulates oxides of nitrogen or carbon monoxide shall not be required if

the applicant demonstrates through modeling that emissions from the new source or modification will not cause a new violation of any national ambient air quality standard for such air contaminants, or make any existing violation of any such standard worse, at the point of maximum ground level impact.

b. not subject to Subsection (a) but which the Control Officer determines would cause a new violation of any national ambient air quality standard, or would make any existing violation of any such standard worse, at the point of maximum ground level impact. Emissions reductions required as a result of this subsection must be shown through modeling to preclude the new, or further worsening of any existing, violation of any national ambient air quality standard that would otherwise result from the operation of the new source or modification, unless such reductions satisfy the requirements of Section (5)(B)(2).

2. Net emissions increases subject to Section (5)(B)(1)(a) shall be mitigated (offset) by reduced emissions from existing stationary or nonstationary sources. Emissions reductions shall be sufficient to offset any net emission increase and shall take effect at the time, or before, initial operation, of the new source, or within 90 days after initial operation of a modification.

3. Emissions offset profiles or equivalent method, as specified by the Air Pollution Control Officer, subject to consultation with the ARB Executive Officer, shall be used to determine whether proposed offsets mitigate the net emissions increases from proposed new sources or modifications.

a. For all offset sources, a yearly emissions offset profile shall be constructed in a manner similar to that used to construct the yearly emissions profile for the proposed new or modified source. Daily emissions reductions which will result from the further control of such sources shall be plotted in descending order. A separate profile shall be constructed for each pollutant. Seasonal offsets shall not be used to mitigate the emissions from nonseasonal sources.

b. In addition, for seasonal offset sources, a quarterly emissions offset profile shall be constructed for the same time period and in the same manner as that used to construct the quarterly emissions profile for the proposed new or modified source. Daily emissions reductions which will result from further control of existing sources shall be plotted on the quarterly offset profile in descending order. A separate profile (which may cover different months) shall be plotted for each pollutant.

c. Adjusted emissions offset profiles shall be constructed by dividing each entry used in the construction of the emissions offset profiles by the offset ratio determined in Subsection (d).

d. The adjusted emissions offset profiles shall be compared with the emissions profiles to determine whether net emissions increases have been mitigated at all points on the profiles.

4. A ratio of emissions offsets to emissions (offset ratio) for new sources or modifications, other than heavy oil production operations, of 1.2:1 shall be required for emissions offsets located either:

i. upwind in the same or adjoining counties; or

ii. within a 15 mile radius of the proposed new source or modification. For emissions offsets located outside of the areas described above, the applicant shall conduct modeling to determine an offset ratio sufficient to show a net air quality benefit in the area affected by emissions from the new source or modification.

b. Emissions from heavy oil production operations shall be offset by a ratio of:

i. 1.0:1 if the emissions used as offsets are owned by the same company and located within the same stationary source which is to be modified:

ii. 1.2:1 if the emissions used as offsets from different companies are located within the same oil field (Western Kern County Fields or Central Kern County Fields as defined in this rule) as the proposed new stationary source or modification;

iii. 1.5:1 if the emissions used as offsets are located outside of the oil field (Western Kern County Fields or Central Kern County Fields as defined in this rule) in which the proposed new stationary source or modification is located, regardless of whether they are owned by the same or different companies.

Notwithstanding any other provisions of this section the yearly emissions profiles and the yearly emissions offset profiles for a source ~~object~~ subject to this section may be constructed based on the daily emissions from the source averaged on a monthly basis. In such event, an offset ratio of 2.0:1 shall be required.

5. If an applicant certifies that the proposed new source or modification is a replacement for a source which was shut down or curtailed after December 28, 1976, emissions reductions associated with such shutdown or curtailment may be used as offsets for the proposed source, subject to the other provisions of this section.

Sources which were shut down or curtailed prior to December 28, 1976, may be used to offset emissions increases for the replacement for such sources, subject to the other provisions of this section provided:

a. the shutdown or curtailment was made in good faith pursuant to an established plan approved by the Control Officer for replacement and emission control, and in reliance on air pollution laws, rules and regulations applicable at the time; and

b. the applicant demonstrates to the satisfaction of the Control Officer that there was good cause (which may include business or economic conditions) for delay in construction of the replacement facilities.

6. Notwithstanding any other provisions of this section any emissions reductions not otherwise authorized by this rule may be used as offsets of emissions increases from the proposed source provided the applicant demonstrates that such reductions will result in a net air quality benefit in the area affected by emissions from the new source or modification; the Control Officer shall consult with the Executive Officer of the Air Resources Board prior to granting such reduction.

7. Emissions reductions resulting from measures required by adopted federal, state, or district laws, rules or regulations shall not be allowed as emissions offsets unless a complete application incorporating such offsets was filed with the District prior to the date of adoption of the laws, rules or regulations, with the exception of Rule 425. Emission reductions resulting from implementation of Rule 425 shall be used in accordance with the provisions in that rule.

8. The Control Officer shall allow emissions reductions which exceed those required by this rule for a new source or modification to be banked for use in the future by the applicant. All such reductions, when used as offsets for the increased emissions from a proposed new source or modifications, shall be used in accordance with the other provisions of this Section.

9. Emission reductions achieved by the stationary source prior to the establishment of the District's banking system shall be used only for determining the net cumulative changes of emissions from that source. Such emission reductions, as well as emission reductions achieved on or after the establishment of the banking system pursuant to Health and Safety Code Sections 40709-40713, shall be allowed to be banked and transferred according to the requirements of the system.

10. For all power plants subject to Section 8, the applicant may, upon written notice to the Control Officer and the Executive Officer of the Air Resources Board, establish an emissions offset bank for a specific power plant at a specific location. The emissions offset bank shall be established no earlier than the date the applicant's Notice of Intention for the power plant is accepted by the California Energy Commission. The emissions offset bank shall lapse if the Commission rejects the applicable power plant or site; however, in such case the applicant may transfer the emissions offsets contained in the bank to another power plant and location for which the Commission has accepted a Notice of Intention. Emissions offsets may be deposited in the bank only by the applicant to construct the power plant, and all emissions offsets contained in the bank shall be used in accordance with Section (5)(B).

11. If an applicant for a resource recovery project using municipal waste demonstrates to the satisfaction of the Control OFficer that the most likely alternative for treating such waste would result in an increase in emissions allowed under existing district permits and regulations, those emissions increases which would not occur as a result of the resource recovery project may be used to offset any net emissions increase from the resource recovery project in accordance with the other provisions of this section.

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12. Emissions reductions of one precursor may be used to offset emissions increases of another precursor of the same secondary air contaminant provided the applicant demonstrates to the satisfaction of the Control Officer that the net emissions increase of the latter secondary precursor will not cause a new violation, or contribute to an existing violation, of any national ambient air quality standard at the point of maximum ground level impact. The ratio of the emission reductions between precursor pollutants of the same secondary air contaminant shall be determined by the Control Officer based on existing air quality data after consultation with the Executive Officer of the Air Resources Board.

6. Permit Condition Requirements for Offsets

The Control Officer shall, as a condition for the issuance of an Authority to Construct for a new stationary source modification and with the prior written consent of the owner or operator of any source which provides offsets:

A. Require that the new source or modification and any new sources which provide offsets shall be operated in the manner assumed in making the analysis required to determine compliance with this rule.

B. Modify, or require modification of, the Permit to Operate for any source used to provide offsets to ensure that emissions reductions at that source which provide offsets will be enforceable and shall continue for the reasonably expected useful life of the proposed source. If offsets are obtained from a source for which there is no Permit to Operate, a written contract shall be required between the applicant and the owner or operator of such source which contract, by its terms, shall be enforceable by the Control Officer to ensure that such reductions will continue for the reasonably expected useful life of the proposed source.

Such modification does not have to take effect until the new modified source, subject to this rule, commences operation.

C. Permit any other reasonably enforceable methods, other than those described in Subsections (A) and (B) which the Control Officer is satisfied will assure that all required offsets are achieved.

7. Analysis, Notice, and Reporting

A. The Air Pollution Control Officer shall determine whether the application is complete not later than 30 calendar days after receipt of the application, or after such longer time as both the applicant and the Air Pollution Control Officer may agree. Such determination shall be transmitted in writing immediately to the applicant at the address indicated on the application. If the application is determined to be incomplete, the determination shall specify which parts of the application are incomplete and how they can be made complete. Upon receipt by the Air Pollution Control Officer of any resubmittal of the application, a new 30-day period

in which the Air Pollution Control Officer must determine completeness shall begin. Completeness of an application or resubmitted application shall be evaluated on the basis of the requirements set forth in (district regulations adopted pursuant to AB 884 regarding information requirements) as it exists on the date on which the application or resubmitted application was received. After the Air Pollution Control Officer accepts an application as complete, the Air Pollution Control Officer shall not subsequently request of an applicant any new or additional information which was not specified in the Air Pollution Control Officer's list of items to be included within such applications. However, the Air Pollution Control Officer may, during the processing of the application, request an applicant to clarify, amplify, correct, or otherwise supplement the information required in such list in effect at the time the complete application was received. Making any such request does not waive, extend, or delay the time limits in this rule for decision on the completed application, except as the applicant and Air Pollution Control Officer may both agree.

B. Following acceptance of an application as complete the Air Pollution Control Officer shall:

1. Perform the evaluations required to determine compliance with this rule and make a preliminary written decision as to whether a permit to construct should be approved, conditionally approved, or disapproved. The decision shall be supported by a succinct written analysis.

2. Within 10 calendar days following such decision, publish a notice of prominent advertisement in at least one newspaper of general circulation in the District stating the preliminary decision of the Air Pollution Control Officer and where the public may inspect the information required to be made available under Subsection (3). The notice shall provide 30 days from the date of publication for the public to submit written comments on the preliminary decision.

3. At the time notice of the preliminary decision is published, make available for public inspection at the Air Pollution Control District's office the information submitted by the applicant, the Air Pollution Control Officer's supporting analysis for the preliminary decision, and the preliminary decision to grant or deny the permit to construct, including any proposed permit conditions, and the reasons therefor. The confidentiality of trade secrets shall be considered in accordance with Section 6254.7 of the Government Code and relevant sections of the Administrative Code of the State of California.

4. No later than the date of publication of the notice required by Subsection (2), forward the analysis, the preliminary decision, and copies of the notice to the Air Resources Board (attn: Chief, Stationary Source Control Division) and the Regional Office of the U.S. Environmental Protection Agency.

5. Consider all written comments submitted during the 30 day public comment period.

6. Within 180 days after acceptance of the application is complete, take final action on the application after considering all written comments. The Air Pollution Control Officer shall provide written notice of the final action to the applicant, the Environmental Protection Agency, and the California Air Resources Board, shall publish such notice in a newspaper of general circulation, and shall make the notice and all supporting documents available for public inspection at the Air Pollution Control District's office.

C. The public notice and reporting requirements set forth in Subsections (B)(2) through (B)(6) shall not be required for any permit which does not include conditions requiring the control of emissions from an existing source.

8. Power Plants

This section shall apply to all power plants proposed to be constructed in the District and for which a Notice of Intention (NOI) or Application for Certification (AFC) has been accepted by the California Energy Commission. The Control Officer, pursuant to Section 25538 of the Public Resources Code, may apply for reimbursement of all costs, including lost fees, incurred in order to comply with the provisions of this section.

A. Within fourteen days of receipt of an NOI, the Control Officer shall notify the Air Resources Board and the Commission of the District's intent to participate in the NOI proceeding. If the District chooses to participate in the NOI proceeding, the Control Officer shall prepare and submit a report to the Air Resources Board and the Commission prior to the conclusion of the nonadjudicatory hearings specified in Section 25509.5 of the Public Resources Code. That report shall include, at a minimum:

1. a preliminary specific definition of BACT and LAER for the proposed facility;

2. a preliminary discussion of whether there is substantial likelihood that the requirements of this rule and all other District regulations can be satisfied by the proposed facility;

3. a preliminary list of conditions which the proposed facility must meet in order to comply with this rule or any other applicable District regulation.

The preliminary determinations contained in the report shall be as specific as possible within the constraints of the information contained in the NOI.

B. Upon receipt of an AFC for a power plant, the Control Officer shall conduct a Determination of Compliance review. This Determination shall consist of a review identical to that which would be performed if an application for an Authority to Construct had been received for the power plant. If the information contained in the AFC does not meet the District's established requirements for permit applications, the Control Officer shall, within 20 calendar days of receipt of the AFC, so inform the Commission, and the AFC shall be considered incomplete and returned to the applicant for resubmittal.

C. The Control Officer shall consider the AFC to be equivalent to an application for an Authority to Construct during the Determination of Compliance review, and shall apply all provisions of this rule which apply to applications for an Authority to Construct.

D. The Control Officer may request from the applicant any information necessary for the completion of the Determination of Compliance review. If the Control Officer is unable to obtain the information, the Control Officer may petition the presiding Commissioner for an order directing the applicant to supply such information.

E. Within 180 days of accepting an AFC as complete, the Control Officer shall make a preliminary decision on:

1. whether the proposed power plant meets the requirements of this rule and all other applicable district regulations; and

2. in the event of compliance, what permit conditions will be required including the specific BACT and LAER requirements and a description of required mitigation measures.

F. The preliminary written decision made under Subsection (E) shall be treated as a preliminary decision under Subsection (7)(A)(1) of this rule, and shall be finalized by the Control Officer only after being subject to the public notice and comment requirements of Section (7). The Control Officer shall not issue a Determination of Compliance unless all requirements ot this rule are met.

G. Within 240 days of the filing date, the Control Officer shall issue and submit to the Commission a Determination of Compliance or, if such a determination cannot be issued, shall so inform the Commission. A Determination of Compliance shall confer the same rights and privileges as a permit to construct only when and if the Commission approves the AFC, and the Commission certificate includes all conditions of the Determination of Compliance.

H. Any applicant receiving a certificate from the Commission pursuant to this section and in compliance with all conditions by the certificate shall be issued a Permit to Operate by the Control Officer.

9. Severability

If any portion of this rule is found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the rule, which shall continue to be in full force and effect.

Exhibit G

orig → File PFA-1 cc: Wright HCB

KERN COUNTY AIR POLLUTION CONTROL DISTRICT

1601 "H" Street, Suite 250
Bakersfield, California 93301-5199
Telephone: (805) 861-3682

LEON M HEBERTSON, M.D.
Director of Public Health
Air Pollution Control Officer

November 10, 1983

Mr. David P. Howekamp, Director
Air Management Division
U.S. E.P.A. Region IX
215 Fremont Street
San Francisco, CA 94105

Dear Mr. Howekamp:

Thank you for your letter of November 7, 1983 in which you expressed concern over the manner in which the District has interpreted our Rule 210.1, Sections 5.8.5 and 5.8.9 with regard to the pending Frito-Lay project. These same concerns were identified by District staff during preliminary discussions with the Frito-Lay in the spring of 1982. Based on discussions and correspondence with the applicant and his legal counsel, the new source was deemed to be a replacement for an existing source which was shut down after 12/28/76. Therefore, according to section 5.8.5 such reductions "may be used as offsets for the proposed source." Additionally, the District determined that section 5.8.9 only relates to the manner in which on-site reductions may be stored over time, and not to the transfer of emission reductions in an offset transaction. This position was adequately summarized by the law offices of Pillsbury, Madison & Sutro in a letter to Dr. Hebertson on July 26, 1982. (attached)

1. The District is also concerned that the 1982 ozone NAP accurately reflects sources of emissions. Consequently, procedures have been implemented to insure that Continental Carbon's emissions will remain in the inventory - perhaps under the name of "The Food Company" or Frito-Lay.

2. Eventhough the permit exempt equipment in this project may result in NO_x emissions of approximately 50% of the non-exempt equipment, such exempt emissions may not be included in our NSR analysis because they are not subject to Rule 210.1 requirements.

3. The District has added a condition requiring daily inspection of all fabric filters and repairs as needed.

4. The District is confident that an independent assessment of this project has been conducted. However, minor wording changes have been made to the Districts analysis to allay E.P.A.'s concern.

5. Unfortunately, a mechanism does not exist by which the District may extend the 30 day public comment period specified in Rule 210.1. We regret that this time limit did not allow your staff sufficient time to review the regulatory concerns associated with this project and every effort will be made to provide E.P.A. with copies of our analyses as quickly as possible.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Citron Toy

Citron Toy
Chief Air Sanitation Officer

CT/dl

Exhibit H

10 APR 1984

Dr. Leon N. Robertson
Air Pollution Control Officer
Kern County Air Pollution
Control District
1601 N Street, Suite 250
Bakersfield, CA 93301

Dear Dr. Robertson:

As a follow-up to our joint meeting with Frito-Lay on April 4, I want to provide a final resolution to the federal issues we have identified in our review of the Kern County permit for this source.

I understand that Frito-Lay and the Continental Carbon Corporation (CCC) acted in good faith under the assumption that both federal regulations and the Kern County NSR rule allowed use of CCC's permitted emissions as offsets for Frito-Lay's project, including the expansion of the project as identified in the SIR. In view of this good faith reliance, EPA will not now require that the permit be revised to conform to national regulations and the approved State Implementation Plan requirements. Furthermore, it does not seem equitable to Frito-Lay to prevent use of the CCC emissions as offsets for a future expansion integral to the project. We do agree with you, however, that CCC emissions and Permits to Operate can only be used by Frito-Lay for the snack foods processing plant at their present site and may not be sold or traded.

I want to reiterate our position regarding the federal restrictions on prior shutdown offsets credits and I ask from you a written commitment to follow this restriction in all future cases until federal regulations change. As we have pointed out in several previous letters and discussions with your staff, we find the provisions of 40 CFR 51.18(j)(iii)(2)(c) prevent use of prior shutdowns as offset credit except for an onsite replacement. In addition, the calculation of credits from a shutdown cannot be based on permitted emissions but must be based on actual emissions (i.e., the average rate at which the unit actually emitted during a two year period immediately preceding the shutdown). EPA expects that the District's commitment to these requirements will prevent any future misunderstandings.

As you indicated, we can avoid repetition of the confusion over the CCC/Frito-Lay trade and permit through early discussions regarding the relevant national restrictions on offsets and trades. We share fully your concern that permit applicants be informed and thus, if possible, avoid purchasing expensive offsets which are invalid for the intended purposes. Please contact us at the earliest moment if you have questions regarding federal regulations; I commit to providing guidance promptly.

Sincerely,

Original Signed By:
David P. Howekamp

David P. Howekamp
Director
Air Management Division

cc: Gordon Duffy, ARB
Harmon Wong-Woo, ARB
Edward Reap, Frito-Lay

Exhibit I

RECEIVED
APR 20 1992
KERN COUNTY AIR
POLLUTION CONTROL DISTRICT

Frito-Lay, Inc.

Code No.
BY ORDER OF THE BD/SUPV
referred to
APCD
copies furnished:
Each Supervisor and CAO
Filed by BD/Supv. 4/16/92
SUE LASITER, Clerk
of the Board of Supervisors
By: A. Johnson

April 13, 1992 92 APR 16 AM : 24

KERN CO. CLERK OF
BD. OF SUPERVISORS
DEPUTY

Mr. David L. Crow
Executive Director/APCO
San Joaquin Valley Unified
Air Pollution Control District
2314 Mariposa Street, #100
Fresno, California 93715

RE: Frito-Lay, Inc., Kern Production Facility
Emission Reduction Banking Certificate

Dear Mr. Crow:

In accordance with the direction of Thomas Goff of your staff, attached is the resubmittal of Frito-Lay's Application for an Emission Reduction Banking Certificate, previously transmitted on March 17, 1992. Pursuant to Mr. Goff's direction, I have also provided a discussion supporting the issuance of the requested Emission Reduction Banking Certificate and enclosed copies of the supporting documentation. Frito-Lay believes that the supporting documentation constitutes the required "District recognition" and clearly indicates that the subject emission reduction credits have undergone rigorous, regulatory review, consistent with current review standards, as these credits were intended to be treated the same as banked emissions. This was the original concept as reflected in District correspondence, dated November 12, 1987 and later reaffirmed in correspondence to USEPA, Region IX, dated July 24, 1991.

As explained in the March 17, 1992 submittal, almost ten years ago, Frito-Lay acquired emission reductions from Continental Carbon (owner of a carbon black facility located west of Bakersfield) to allow for the location of a new snack food production facility and regional warehouse in Kern County. At the time these emission reductions occurred, there was no banking rule in Kern County. As further explained in the March 17 submittal, these reductions were formally recognized in writing by the District (prior to the County's adoption of a banking rule which occurred on April 27, 1983) as available for offsets (ref. enclosed correspondence from T. Paxson, dated February 25, 1983). During the final approval of the Authorities to Construct for Phase I development of Frito-Lay's Kern County production complex, additional recognition of these reductions was provided in correspondence from the District and from the Region IX office of the USEPA (ref. enclosed correspondence dated 11/10/83 and 4/10/84).

We have obtained the concurrence of expert legal counsel that this written recognition by the District entitles Frito-Lay to an Emission Reduction Banking Certificate pursuant to Rule 230.1, the Emission Reduction Credit Banking Rule of the San Joaquin Valley Unified APCD. Rule 230.1 at IV A.2. specifically provides that emission reductions occurring prior to January 1, 1988 "for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets shall be eligible for emissions reductions banking certificates...".

As Kern County did not have a banking rule at the time the emission reductions became available, Frito-Lay is entitled to a banking certificate in accordance with the literal interpretation of the rule. Briefly, this interpretation of the language of the rule provides that if a given county did not have a banking rule in effect when pre-1988 emission reductions became available, then the formal, written recognition of such reductions by the District will be recognized.

The language of the rule clearly delineates between pre-1988 emission reductions, those occurring prior to and those after a banking rule. The key issue raised by Rule 230.1 is what legal mechanism was in place to recognize emission reduction credits at the time these credits were originally recognized by the District as available for offsets. If the District at the time had a banking rule, then conformance to this rule would have been required. On the other hand, if no rule existed when the credits became available, as was the scenario with Frito-Lay's emission reductions, then the formal, written recognition from the District was the only mechanism available to identify and preserve credits for use as offsets.

Enclosed is the documentation that the emission reductions represented in the attached Application were formally recognized in writing by the District (on several occasions) as available for offsets at a time when Kern County had no banking rule. Documentation which supports the quantity of emission reduction credits available to Frito-Lay is also enclosed.

In addition to Frito-Lay's strong legal entitlement to a banking certificate based on the language of Rule 230.1, it also has a strong equitable position. After the adoption of the banking rule in Kern County, Frito-Lay sought to have the already recognized emission reductions added to the bank(ref. enclosed correspondence from M.Barr to L.Hebertson, dated 12/21/87). The District determined that it would prefer to continue preserving the credits in valid Permits to Operate, which Frito-Lay has kept current through annual fee payments.

We are eager to resolve the current confusion and secure the banking certificate for the emission reductions held by Frito-Lay. This certificate is vital to our immediate and long term expansion plans for the Kern facility. We would be available to meet with you and your staff to aid in expediting the issuance of the Emission Reduction Banking Certificate for Frito-Lay.

Sincerely,
FRITO-LAY, INC.

HC Bradbury

H.C. Bradbury
Group Manager
Environmental Policy and Affairs

Attachment
Enclosure

cc: Pauline Larwood
Carl Hettinger
Seyed Sadredin
Thomas Goff
Robert T. Stewart, Esq.

Exhibit J

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office • 2700 M St., Suite 275 • Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-1

Issued To: **FRITO-LAY, INC.**
March 1, 1993

CONSUMED BY S-158-1 9/24/93 RM

Location of Reduction: **20807 Stockdale Highway**
Bakersfield
Sec 14, T32S, R23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
229,968 lbs	232,523 lbs	235,078 lbs	235,078 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: _____

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-1

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 • Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-2

Issued To: **FRITO-LAY, INC.**
March 1, 1993

Consumed By S-158-2 9/14/93 PKY

Location of Reduction: **20807 Stockdale Highway**
Bakersfield
Sec 14, T32S, R23E

For NOx Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
18,702 lbs	18,910 lbs	19,118 lbs	19,118 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: _____

David L. Crow, APCO

Seyed Sadredin

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-2

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-3

Issued To: **FRITO-LAY, INC.**
March 1, 1993

CONSUMED By S-158-3 9/24/98

Location of Reduction: **20807 Stockdale Highway**
Bakersfield
Sec 14, T32S, R23E

For CO Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
90,000 lbs	91,000 lbs	92,000 lbs	92,000 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: _____

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-3

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-4

Issued To: **FRITO-LAY, INC.**
March 1, 1993

CONSUMED BY
S-156-4 9/24/93
PM4

Location of Reduction: **20807 Stockdale Highway**
Bakersfield
Sec 14, T32S, R23E

For PM10 Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
24,975 lbs	25,252 lbs	25,530 lbs	25,530 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: _____

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office • 2700 M St., Suite 275 • Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-5

Issued To: FRITO-LAY, INC.
March 1, 1993

CONSUMED BY S-158-5 9/24/93

Location of Reduction: 20807 Stockdale Highway
Bakersfield
Sec 14, T32S, R23E

For SO2 Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
161,703 lbs	161,500 lbs	165,296 lbs	165,296 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: _____

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

Exhibit K

Fwd: ERC Project S-1011223

Inbox x

Print all

David Abell <david.abell@sierraclub.org> 9:02 AM (0 minutes ago)

to me

——— Forwarded message ———
From: **Homero Ramirez** <Homero.Ramirez@valleyair.org>
Date: Tue, May 21, 2013 at 1:01 PM
Subject: ERC Project S-1011223
To: "petra.pless@gmail.com" <petra.pless@gmail.com>

Petra:

Here is the copy of the evaluation (and ERC certificates) for project S-1011223, the ERC transfer in which I noted that the special use provision was removed for the certificates.

Homero

From: Homero Ramirez
Sent: Tuesday, May 21, 2013 12:58 PM
To: 'petra.pless@gmail.com'
Subject: ERC Project S-1000991

Hi Petra.

Per our telephone conversation, attached is a copy of the evaluation (and ERC certificates) for project S-1000991 for transfer of ERCs from Frito Lay to Oceanair. I will send you the information for the other project in a separate email.

If you have any questions, please contact me.

Homero Ramirez
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308
Tel. (661) 392-5616
Fax (661) 392-5585

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Click here to Reply or Forward

ERC TRANSFER OF OWNERSHIP REVIEW

Facility Name: OceanAir Environmental, LLC
Mailing Address: 4220 Donlon Road
Somis, CA 93066

Contact Name: Mahesh Talwar, President
Telephone: (805) 386-1882

Engineer: Steve Tomlin
Date: December 6, 2001

Lead Engineer: Leonard Scandura, Supervising Air Quality Engineer LWS
Date: 12/21/01

Project: 1011223
ERC # Tendered: S-1474-1
New ERC #s: S-1700-1
Received: December 3, 2001

I. PROPOSAL:

Ocean Air Environmental is requesting a transfer of ownership of an Emission Reduction Credit Certificate (ERC) to Duke Energy Avenal LLC. Ocean Air has submitted a letter releasing the ownership of the entire certificate to Duke Energy.

Old Ocean Air Environmental ERC Number	New Duke Energy Avenal ERC Number
S-1474-1	S-1700-1

II. APPLICABLE RULES:

Rule 2301 Emission Reduction Credit Banking (12/17/92)

III. COMPLIANCE REVIEW:

Rule 2301 Emission Reduction Credit Banking (12/17/92)

Ocean Air Environmental has filed to transfer ownership of Emission Reduction Credit (ERC) certificates in accordance with Rule 2301, section 7.2, and has submitted a written statement designating Duke Energy as the new owner of the certificate. Compliance is expected.

IV. RECOMMENDATION:

Issue ERC banking certificate S-1700-1 in the following allotments and as shown on the draft banking certificate.

Certificate Allotment:

ERC Certificate Reissue Amounts, lbs

	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
ERC S-1700-1,VOC	87,500	87,500	87,500	87,500

V. BILLING INFORMATION:

The applicant has paid $60 for processing the transfer of ownership of one ERC certificate. No other processing fees are required; therefore, additional billing is not required at this time.

San Joaquin Valley
Air Pollution Control District

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-1474-1

T & O to Duke Energy Arend LLC as S-1700-1 12-18-01 SVT

ISSUED TO: Ocean Air Environmental

ISSUED DATE: October 16, 2000

LOCATION OF REDUCTION: 20807 Stockdale Highway
Bakersfield, CA
Section 14, Township 32S, Range 23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
87,500 lbs.	87,500 lbs.	87,500 lbs.	87,500 lbs.

[ ] Conditions Attached

Method of Reduction

[x] Shutdown of Entire Stationary Source, S-1637 (Split and re-issue of Emissions Reduction Credit Certificate #S-1463-1)

[ ] Shutdown of Emission Unit

[ ] Other:

Pursuant to section 4.2.5.1 of Rule 2201, these reductions may not be used as offsets for emissions from a major source or for a Title I Modification. Due to previous agreements regarding these reductions, this prohibition does not apply to the use of these reductions as offsets for the snack food facility located at 22801 Highway 58 in Bakersfield, California.

David L. Crow, APCO

Seyed Sadredin
Director of Permit Service

San Joaquin Valley
Air Pollution Control District

Southern Regional Office • 2700 M Street, Suite 275 • Bakersfield, CA 93301-2370

Emission Reduction Credit Certificate
S-1700-1

T/O to DUKE ENERGY NORTH AMERICA S-5243 8/17/04 as cert S-2083-1 filed in S-1637 1043224

ISSUED TO: DUKE ENERGY AVENAL, LLC

ISSUED DATE: December 13, 2001

LOCATION OF REDUCTION: 20807 STOCKDALE HIGHWAY
BAKERSFIELD, CA (MAJOR SS)

SECTION: 14 TOWNSHIP: 32S RANGE: 23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
87,500 lbs	87,500 lbs	87,500 lbs	87,500 lbs

[ ] Conditions Attached

Method Of Reduction

[X] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Units
[ ] Other

SHUTDOWN ENTIRE STATIONARY SOURCE

Use of these credits outside the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) is not allowed without express written authorization by the SJVUAPCD.

David L. Crow, Executive Director / APCO

Seyed Sadredin, Director of Permit Services

Exhibit L

DRAFT

ERC APPLICATION REVIEW

DEEMED COMPLETE:	6/22/92	ENGINEER:	Lance Ericksen
DATE START:	4/16/92	TITLE::	Senior AQE
DATE FINISH:	8/21/92		

6026001/101/201/401/501/601

Facility Name: FRITO-LAY, INC.
Mailing Address: 222801 Highway 58
Bakersfield, CA 93312

Project #: 6026 920416
WP File #: 92LE026

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

I. ~~PROPOSAL~~: Summary shutdown of

The applicant is requesting ERC Banking Certificates pursuant to Rule 230.1 IV.A.1. - reductions occurring prior to January 1, 1988. The reductions were obtained from Continental Carbon a carbon black production facility for use as offsets at the Frito-Lay facility. These reductions were recognized in writing by the District as available for offsets prior to adoption of the Kern County banking rule for use only at the Frito-Lay facility. Any credits available for banking will also be limited for use as offsets at the Frito-Lay Facility. A portion of these reductions was used for approval of the current Frito-Lay facility in addition a portion of the reductions were donated to the KCAPCD in 1989. The reductions dedicated to previous projects and the portion donated to the District is not surplus and the applicant has not requested to bank these amounts.

this the source to apply for banking pursuant to ____

Include Results, reduction - actual except NO_2 previously recognized

II. APPLICABLE RULES:

Rule 230.1 - Emission Reduction Credit Banking (March 11, 1992)

To qualify for banking the emissions reductions must comply with the requirements of subsection IV.A.2. The requirements of this subsection are summarized below:

1. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

2. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable.

3. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

4. The reductions are included in or have been added to the 1987 emissions inventory.

5. The banking application must be filed within 180 days of the date of rule adoption.

III. PROJECT LOCATION:

The carbon black facility was located 8 miles west of Bakersfield on Stockdale Highway Section 14, Township 32S, Range 23E. The Frito-Lay facility is located west of Bakersfield on highway 58 at Section 20, Township 29S, Range 25E. A map showing the relative locations of the facilities are shown on page 3.

Method of Generating Emission Reductions

IV. ~~PROCESS DESCRIPTION~~:

The carbon black facility was comprised of two independent carbon black production trains. Unit 1 produced a hard type or tread grade carbon black. Unit 2 produced a soft type or carcass grade carbon black. Both units use the oil furnace process for production of carbon black. Flow diagrams and a description of the process used is shown on page 5.

~~Sequence of events.~~ Purchased credits by obtaining permits
permits Maintained

Skip — process description
more to calculations

V. EQUIPMENT LISTING:

Credits generated are associated with eight permits to operate for the carbon black facility the equipment associated with each permit is:

6026001	Unit 1 Reactors
6026002	Unit 1 Pulverizer/pelletizers
6026003	Unit 1 Dryer
6026004	Unit 1 Screens/separators/storage/bagging/loadout
6026005	Unit 2 Reactors
6026006	Unit 2 Pulverizer/pelletizers
6026007	Unit 2 Dryer
6026008	Unit 2 Screens/separators/storage/bagging/loadout

Skip

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

No equipment control technology evaluation is required. This project is to bank previously recognized emission reduction credits for black manufacturing facility where operations have ceased.

VII. CALCULATIONS:

A. PM-10, CO and VOC Emissions Reductions

Emission reductions previously recognized by the District of PM-10, CO and VOC are based on AP-42 emission factors and actual carbon black production for the facility. The baseline carbon black production emission factors and calculation of actual emission reductions of TSP, CO and VOC are shown on pages 9-14.

Conversion of TSP to PM-10

The AP-42 emission factor is for TSP. Information submitted by the applicant demonstrates that all the size of carbon black produced at the facility is less than 10 microns. It can therefore be concluded that all emissions of particulate matter from the carbon black production facility are also 10 microns or less and thus the TSP emissions are all PM-10. The basis for this conclusion is show on pages 15-21.

AP-42

TABLE 5.3-3. EMISSION FACTORS

EMISSION FACTOR

Process	Particulate[b] kg/Mg	Particulate[b] lb/ton	Carbon Monoxide kg/Mg	Carbon Monoxide lb/ton	Nitrogen Oxides kg/Mg	Nitrogen Oxides lb/ton
Oil furnace process						
Main process vent	3.27[d] (0.1-5)	6.53[d] (0.2-10)	1,400[e] (700-2,200)	2,800[e] (1,400-4,400)	0.28[e] (1-2.8)	0.56[e] (2-5.6)
Flare	1.35 (1.2-1.5)	2.70 (2.4-3)	122 (108-137)	245 (216-274)	NA	NA
CO boiler and incinerator	1.04	2.07	0.88	1.75	4.65	9.3
Combined Dryer vent						
Bag filter[h]	0.12 (0.01-0.40)	0.24 (0.02-0.80) used .45 for uncontrolled Vent			0.36 (0.12-0.61)	0.73 (0.24-1.22)
Scrubber[h]	0.36 (0.01-0.70)	0.71 (0.02-1.40)			1.10	2.20
Pneumatic system vent[h]						
Bag filter	0.29 (0.06-0.70)	0.58 (0.12-1.40)				
Oil storage tank vent[i]						
Uncontrolled						
Vacuum cleanup system vent[h]						
Bag filter	0.03 (0.01-0.05)	0.06 (0.02-0.10)				
Fugitive emissions[h]	0.10	0.20				
Solid waste incinerator[j]	0.12	0.24	0.01	0.02	0.04	0.08
Thermal process[k]	Neg	Neg	Neg	Neg	Unknown[l]	Unknown[l]

[a]Expressed in terms of weight of emissions per unit weight of carbon black produced. Blanks indicate no emissions. Most plants use bag filters on all process trains for product recovery except solid waste incineration. Some plants may use scrubbers on at least one process train. NA = not available.

[b]The particulate matter is carbon black.

[c]Emission factors do not include organic sulfur compounds which are reported separately in Table 5.3-2. Individual organic species comprising the nonmethane VOC emissions are included in Table 5.3-.2

[d]Average values based on surveys of plants (References 4-5).

[e]Average values based on results of 6 sampling runs conducted at a representative plant with a mean production rate of 5.1 x 10 Mg/yr (5.6 x 10 ton/yr). Ranges of values are based on a survey of 15 plants (Reference 4). Controlled by bag filter.

[f]Not detected at detection limit of 1 ppm.

FOR CARBON BLACK MANUFACTURE[a]

RATING: C

Sulfur Oxides		Methane		Nonmethane VOC[c]		Hydrogen Sulfide	
kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
0[e,f] (0-12)	0[e,f] (0-24)	25[e] (10-60)	50[e] (20-120)	50[e] (10-159)	100[e] (20-300)	30[e] 5S-13S[g]	60[e] 10S-26S[g]
25 (21.9-28)	50 (44-56)			1.85 (1.7-2)	3.7 (3.4-4)	1	2
17.5	35.2			0.99	1.98	0.11	0.22
0.26 (0.03-0.54)	0.52 (0.06-1.08)						
0.20	0.40						
				0.72	1.44		
0.01	0.02			0.01	0.02		
Neg	Neg			Neg	Neg	Neg	Neg

[g]S is the weight percent sulfur in the feed.

[h]Average values and corresponding ranges of values are based on a survey of plants (Reference 4) and on the public files of Louisiana Air Control Commission.

[i]Emission factor calculated using empirical correlations for petrochemical losses from storage tanks (vapor pressure = 0.7 kPa). Emissions are mostly aromatic oils.

[j]Based on emission rates obtained from the National Emissions Data System. All plants do not use solid waste incineration. See Section 2.1.

[k]Emissions from the furnaces are negligible. Emissions from the dryer vent, pneumatic system vent and vacuum cleanup system and fugitive sources are similar to those for the oil furnace process.

[l]Data are not available.

TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S})\ (64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /60	0 /4293
Dryer Vent	0.52/0	37.2/0
[illegible]	[illegible]	[illegible]
Boilers	142S (lbs/10^6 gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S)\ (0.50)\ (64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

CONTINENTAL CARBON EMISSION CREDITS

I. Carbon Black Production (avg. of yrs. '72 through '79): 52,288,712 lbs/yr
(See Attachment 1)

$$\frac{52,228,712 \text{ lbs/yr}}{2000 \text{ lbs/ton } (365 \text{ days/yr})} = 71.55 \text{ ton/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP42 emission factors for Carbon Black Manufacture (B Oil furnace process), 7/79.

PROCESS	EMISSION FACTORS (lbs/ton of Product)			
	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Main Process Vent	6.53	2,800	100	60
Dryer Vent Uncontrolled (Firebox)	.45	---	---	---
Pneumatic System Vent Bag Filter	.58	---	---	---
Oil Storage Tank Vent	---	---	1.44	---
Vacuum Cleanup System Vent	.06	---	---	---
Fugitive Emissions	.20	---	---	---
SOURCE TOTAL	7.82	2,800	101.44	60
Less 29.5% for Modification in 1978 does not impact TSP.	---	826	29.92	17.70
Emission Factor Total	7.82	1,974	71.52	42.30

ATTACHMENT 1

BAKERSFIELD PLANT PRODUCTION

YEAR	TREAD	CARCASS	TOTAL	
1981	8,897,300 lbs.	7,263,200 lbs.	16,160,500 lbs.	(8 mos. + 10 days = .6932 yr.)
1980	11,777,100 "	15,452,300 "	27,229,400 "	
1979	21,116,800 "	27,492,600 "	48,609,400 "	
1978	20,848,100 "	24,922,400 "	45,770,500 "	
1977	30,000,300 "	25,828,200 "	55,828,500 "	
1976	18,703,000 "	21,786,500 "	40,489,500 "	
1975	24,327,900 "	25,190,700 "	49,518,600 "	
1974	32,349,100 "	26,538,000 "	58,887,100 "	
1973	32,037,800 "	30,009,200 "	62,047,000 "	
1972	29,294,000 "	27,865,100 "	57,159,100 "	
Averages	22,935,140	23,234,820	46,169,960 lbs.	(avg. 9.6932 yrs)
Averages	24,494,900	25,009,444	49,504,344 lbs.	(avg. 9 yrs-'72 thru '80)
Averages	26,084,625	26,204,087	52,288,712 lbs.	(avg. 8 yrs - '72 thru '79)

December 22, 1982

CALCULATION OF EMISSION REDUCTION CREDITS
(REVISED)

I. Line #1 (tread) Carbon Black Production (avg. of yrs. '72 through '79): 26,084,625 lbs.

$$\frac{26,084,625 \text{ lbs/yr}}{2,000 \text{ lbs/Ton (365 days/yr)}} = 35.73 \text{ Tons/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP-42 emission factors for Carbon Black Manufacture (B Oil Furnace Process), 7/79, and the avg., daily production rate shown above.

LINE #1 EMISSIONS (lbs/day)

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Uncontrolled	279.4	100,044.0	3,624.4	2,143.8
Less 29.5% for 1978 Modification	-----	29,513.0	1,069.2	632.4
Total ERC for Line #1	279.4	70,531.0	2,555.2	1,511.4

III. Line #2 (carcass) Carbon Black Production (avg. of yrs. '72 through '79): 26,204,087 lbs

$$\frac{26,204,087 \text{ lbs/yr}}{2,000 \text{ lbs/Ton (365 days/yr)}} = 35.90 \text{ Tons/day Carbon Black}$$

IV. The following emission estimates utilize USEPA AP-42 emission factors for Carbon Black Manufacture (B Oil Furnace Process), 7/79, and the avg., daily production rate shown above.

LINE #2 EMISSIONS (lbs/day)

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Uncontrolled	280.74	100,520.0	3,641.7	2,154.0
Less 39% for 1978 Modification	-----	39,202.8	1,420.3	840.1
Total ERC for Line #2	280.74	61,317.2	2,221.4	1,313.9

1054S/CTW/ss

V. Total Emission Credit

A.

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Line #1	279.4	70,531.0	2,555.2	1,511.4
Line #2	280.74	61,317.2	2,221.4	1,313.9
Total Credit lbs/day	560.1	131,848.2	4,776.6	2,825.3

B. SO_x - Specific Limiting Condition is 198.9 lbs/hr

198.9 lbs/hr (24 hr/day) = 4,773.6 lbs/day

H_2S Conversion to SO_2 (1978 Modification)

Source	H_2S	SO_2
Line #1	632.4	1,188.9
Line #2	840.1	1,579.4
		2,768.3 lbs/day

SO_2 Emission Credit

4,773.6 lbs/day (specific limiting condition)
2,768.3 lbs/day (H_2S conversion - '78 mod.)

7,541.9 lbs/day TOTAL SO_2 EMISSION CREDIT

C. NO_x - Specific Limiting Condition is 44.14 lbs/hr

44.14 lbs/hr (24 hrs/day) = 1,059.36 lbs/day

1054S/CTW/ss

Quantification of PM10 Emissions

Background

Unit 1 reactor at Continental Carbon's Bakersfield facility produced a hard type or tread grade (HAF) carbon black. A soft type or carcass grade (GPF) carbon black was produced in Unit 2 reactor. Emission reductions for particulate were calculated using AP-42 emission factors for Carbon Black manufacture(B oil furnace), 7/79. These emission factors have remained unchanged in the more current 5/83 edition. These emission factors were applied to a carbon black production rate of 71.55 tonnes/day, which was an average of eight years production spread over 365 operating days per year.

Discussion

From our records' search, particle size data for the Continental Carbon facility in Bakersfield is not available. However, technical literature on carbon black processing and the associated emission sources address particle size, specifying mean particle size for the various grades of carbon black produced. This information is provided below for the grades of carbon black produced at the Bakersfield facility.

Grade	Symbol	Mean Particle Size--nm
High Abrasion Furnace-Low Structure	HAF-LS	25 to 26.5
High Abrasion Furnace-High Structure	HAF-HS	22 to 25
General Purpose Furnace	GPF	50 to 55

Source: Serth, R.W. and Hughes, T.W., Source Assessment: Carbon Black Manufacture, October, 1977, pp. 10-13.

Conclusion

As noted in the process description for Carbon Black manufacturing (AP42, 5/83), "...the unburned carbon is collected as an extremely fine black fluffy particle, 10 to 500 nm diameter". Although particle size data was not located in the District's files or in Frito-Lay's records, a literature search revealed that particle size is a function of the grade of carbon black produced. The mean particle size for the grades produced at the Bakersfield facility fall in the range of 22--55 nm. As noted in the Engineering and Cost Study of Air Pollution Control for the Petrochemical Industry, Volume 1: Carbon Black Manufacture by the Furnace Process, "...size distribution of particulates

Exhibit M

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WRITER'S DIRECT DIAL NUMBER

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WALNUT CREEK, CALIFORNIA 94
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667 K STREET, N.W.
WASHINGTON, D.C. 20006
TELEPHONE (202) 887-030

November 12, 1987

Frito-Lay, Inc. - Air Pollution - Highway 58 Project, Kern County, California

Dr. Leon M. Hebertson
Air Pollution Control Officer
Kern County Air Pollution Control District
1601 "H" Street, Suite 150
Bakersfield, CA 93301-5199

Dear Dr. Hebertson:

To follow up our meetings regarding the Frito-Lay Highway 58 Project in Kern County, we request confirmation of the remaining balance of emission reduction credits available to Frito-Lay at the Project site.

As background, Frito-Lay started planning the Project in 1982, contracted for the necessary emission reduction credits for use as emission offsets in 1982 and, in 1983, began submitting applications to the District for Authorities to Construct elements of the Project. Initial Project elements have now been completed and are operational. At this time, further Project elements are in a preliminary stage and further applications for Authorities to Construct them would be premature. As indicated in the Frito-Lay Business Discussion and Project Descriptions attached, Frito-Lay intended its new Kern County manufacturing complex to be constructed in stages and it will consist of various types of processes normally conducted by it and its affiliates.

In response to the elaborate process of obtaining applicable permits from various regulatory agencies and in response to the developing market for food products manufactured by Frito-Lay and its affiliates on the West Coast, development of the Project has necessarily been a lengthy process which continues through today and will continue for some period of time.

To meet the specific regulatory requirements of the Kern County Air Pollution Control District, Frito-Lay was required to obtain emission reduction credits to utilize as offsets for various increases in air pollutant emissions from elements of the Project. In order to provide sufficient offsets for all of the possible particular elements of the full Project, Frito-Lay contracted with Continental Carbon Corporation (CCC) in good faith in compliance with both Federal regulations and the Kern County NSR Rule. The CCC emissions credits were required both for specific Project elements which had passed through the design and engineering phase at that time and for those Project elements to be located at the Project site in the future. At the present time, only a portion of the originally available CCC emissions credits have been consumed by completed and operational Project elements and, accordingly, Frito-Lay wishes to ask the District to confirm the amounts available for future Project elements at the Project site.

Frito-Lay does not request use of the remaining CCC emissions credits at any site other than the Project site on Highway 58 and does not request permission to sell or trade excess CCC emissions credits.

The attached materials should provide the factual basis upon which the District can confirm the remaining amount of CCC emissions available for use by Frito-Lay in permitting future items of equipment at the Project site pursuant to the Rules and Regulations of the Kern County APCD.

In addition, we ask that you consider the following legal bases in support of the requested District confirmation of remaining CCC emissions credits:

(1) In order to construct and develop the full Project, Frito-Lay was required by Kern County APCD rules (and, in turn, Kern County was required by the Clean Air Act and EPA regulations) to obtain and apply emission reduction credits for use as offsets against the increased emissions from the Project (Clean Air Act § 173; EPA Emission Offset Interpretive Ruling, 40 C.F.R., Part 51; Kern County APCD Rules 210.1.3C, 210.1.5B). Frito-Lay obtained the CCC credits, paid the CCC PTO emission fees, held the CCC PTO's in its name and relied on them to mitigate Project emissions pursuant to Kern County APCD Rule 210.1.5B2. Having provided the offsets required

to mitigate a project emissions, Frito-Lay should not later be subject to loss of these established offsets through discounting or disallowance for use in mitigating the remaining emissions from later Project elements.

(2) The Project is large (see Frito-Lay Project Description attached), has an extended buildout time and must respond to a dynamic, developing marketplace (see Frito-Lay Business Discussion attached). Accordingly, Frito-Lay endeavored to obtain sufficient offsets to last for the duration of the full Project build-out. Frito-Lay is requesting that the CCC emission reduction credits be confirmed for use for the balance of development at the Project site, in accordance with basic Districts practice in cases of lengthy, phased projects.

(3) Had an approved, fully functioning air pollution emission bank been available, Frito-Lay would have been able to use such a bank to assemble the necessary emission reduction credits, use them as necessary and store the balance over time. By analogy to such a functioning banking system, Frito-Lay acquired the full amount of emission reduction credits anticipated to be necessary for the Project site, has applied them to specific ATC's issued to date and wishes to store the rest for the balance of the necessary Project ATC's. Therefore, Frito-Lay's maintenance of the CCC PTO's was essentially equivalent to duly banked emissions and should be available for remaining Project elements.

(4) Both Kern County APCD and EPA carefully examined Frito-Lay's use of CCC emission credits and allowed them to be used for the Project subject to extraordinary, specific use restrictions. Frito-Lay concurred and continues to concur with the decision that any remaining CCC emission reduction credits may be used for "future expansion integral to the SR 58 Project" and recognizes that the remaining emission reduction credits "can only be used at the Highway 58 site," as stated in EPA's letter of April 10, 1984.

Accordingly, Frito-Lay requests that the remaining emission reductions credits represented by Kern County APCD

Permits to Operate Nos. 6026001-008 be preserved formally for use as emission offsets for the future Authorities to Construct issued to Frito-Lay to build out its Project at the 100 acre, Highway 58 site. In particular, we ask that the remaining amounts (lbs/day/pollutant) of available credits be specified in a formal, enforceable permit condition applicable to the Project, pursuant to Kern County APCD Rule 210.1.6.

We trust that this letter and its attachments adequately describe the uses for the remaining emission reduction credits and that the method requested for their preservation for future use is acceptable to the District. We look forward to your favorable response and the final resolution of this matter of vital interest to the future of Frito-Lay in Kern County.

Very truly yours,

Michael R. Barr

Encs.

cc: Mr. J. Rich, Plant Manager
Mr. H. C. Bradbury

FRITO-LAY, INC. - KERN COUNTY
AUTHORITY TO CONSTRUCT APPLICATIONS
PERMITS TO OPERATE
15 OCTOBER 1987

TABLE 1

EMISSIONS - LBS/DAY

APCD PERMIT # 3082	DESCRIPTION	PARTICULATES	NOx	SO2	SO4	HC	CO
PERMITS TO OPERATE GRANTED							
001	BOILER #1	14.16	99.93	251.26	4.24	2.81	35.40
003	PC #1	73.64					
005	DTC #1	16.80					
006	DTC #2	16.80					
007	CORN HANDLING	7.44					
008	VOID	-					
009	CANCELLED	-					
010	CANCELLED	-					
011	CANCELLED	-					
012	WWT SYSTEM	-					
SUBTOTAL		128.84	99.93	251.26	4.24	2.81	35.40
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED							
004	FCC #1	30.00					
013	FCC #2	30.00					
014	COGEN	29.76	299.52	1.28	4.09	32.88	345.60
015	STARCH DRYER	16.82					
SUBTOTAL		106.58	299.52	1.28	4.09	32.88	345.60
TOTAL INSTALLED EMISSIONS		235.42	399.45	252.54	8.33	35.69	381.00
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED							
002	BOILER #2	9.59	99.93	1.00	1.00	2.81	61.01
016	PC #2	73.68					
SUBTOTAL		83.27	99.93	1.00	1.00	2.81	61.01
TOTAL PERMITTED EMISSIONS		318.69	499.38	253.54	9.33	38.50	442.01

FRITO-LAY, INC. - KERN COUNTY
EMISSION OFFSETS REQUIRED
15 OCTOBER 1987

TABLE 2

EMISSION OFFSETS
REQUIRED @ 1.2:1
EMISSIONS - LBS/DAY

APCD PERMIT # 3082	DESCRIPTION	PARTICULATE	NOx	SO2	SO4	HC	CO	H2S
PERMITS TO OPERATE								
001	BOILER #1	16.99	119.92	301.51				
003	PC #1	88.37						
005	DTC #1	20.16						
006	DTC #2	20.16						
007	CORN HANDLING	8.93						
008	VOID							
009	CANCELLED							
010	CANCELLED							
011	CANCELLED							
012	WWT SYSTEM							
SUBTOTAL		154.61	119.92	301.51				
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED								
004	FCC #1	36.00						
013	FCC #2	36.00						
014	COGEN	35.71	359.42	1.54				
015	STARCH DRYER	20.18						
SUBTOTAL	-	127.90	359.42	1.54				
TOTAL INSTALLED OFFSETS REQ'D.		282.50	479.34	303.05				
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED								
002	BOILER #2	11.51	119.92	1.20				
016	PC #2	88.42						
SUBTOTAL		99.92	119.92	1.20				
TOTAL PERMITTED OFFSETS REQ'D.		382.43	599.26	304.25				

FRITO-LAY, INC. - KERN COUNTY
EMISSION REDUCTIONS AVAILABLE
15 OCTOBER 1987

TABLE 3

EMISSION REDUCTIONS
EMISSIONS - LBS/DAY

APCD PERMIT # 6026	DESCRIPTION	PARTICULATES	NOx	SO2	SO4	HC	CO	H2S
PERMITS TO OPERATE								
001	UNIT 1 REACTORS							
002	UNIT 1 PULVERIZER/PELLETIZERS							
003	UNIT 1 DRYER							
004	UNIT 1 SCREENS/SEPARATORS/STORAGE/BAGGING/LOADOUT							
005	UNIT 2 REACTORS							
006	UNIT 2 PULVERIZER/PELLETIZERS							
007	UNIT 2 DRYER							
008	UNIT 2 SCREENS/SEPARATORS/STORAGE/BAGGING/LOADOUT							
TOTAL		560.1	1059.4	4773.6	0	4776.6	131,848.2	753.4

FRITO-LAY, INC. - KERN COUNTY
EMISSION REDUCTIONS
OFFSETS APPLIED @ 1.2:1
15 OCTOBER 1987

TABLE 4

REMAINING EMISSION REDUCTIONS
EMISSIONS - LBS/DAY

APCD PERMIT # 3082 DESCRIPTION	PARTICULATES	NOX	SO2	SO4	HC	CO	H2S
INITIAL EMISSION REDUCTIONS FROM CCC							
TOTAL	560.1	1059.4	4773.6	0	4776.6	131,848.2	753.4
PERMITS TO OPERATE GRANTED							
001 BOILER #1	16.99	119.92	301.51				
003 PC #1	88.37						
005 DTC #1	20.16						
006 DTC #2	20.16						
007 CORN HANDLING	8.93						
008 VOID							
009 CANCELLED							
010 CANCELLED							
011 CANCELLED							
012 WWT SYSTEM							
OFFSET SUBTOTAL	154.61	119.92	301.51	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	405.49	939.48	4472.09	0	4776.6	131,848.2	753.4
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED							
004 FCC #1	36.00						
013 FCC #2	36.00						
014 COGEN	35.71	359.42	1.54				
015 STARCH DRYER	20.18						
OFFSET SUBTOTAL	127.89	359.42	1.54	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	277.6	580.06	4470.55	0	4776.6	131,848.2	753.4
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED							
002 BOILER #2	11.51	119.92	1.20				
016 PC #2	88.42						
OFFSET SUBTOTAL	99.93	119.92	1.20	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	177.67	460.14	4469.35	0	4776.6	131,848.2	753.4

277.6 - 99.93 = 177.67

BUSINESS DISCUSSION
FRITO-LAY KERN COUNTY PROJECT

BACKGROUND

Frito-Lay has been requested to describe the Kern County "project and future expansion plans for the project" with regard to use and preservation of the remaining CCC ERC's. The remaining ERC's are necessary as emission offsets for future expansion and remaining development of the project. The attached description of the "Frito-Lay Kern County Project" is in response to that request. The project is described in terms of the 100 acre, Highway 58 site. The expansion of the project is described as the full development of the 100 acre, highway 58 site within certain specific environmental impacts and specific parameters to residents of Kern County.

Specific initial project processes and operations were the subject of specific past permit applications and numerical computations. They were also cited as examples of the types of activities that may be included in the fully developed project in various correspondence and discussions. However, the entire project has always been referred to as a "major food processing/distribution complex", or similar generic words, in all communications on this matter by all of the parties involved, including Kern County APCD and the EPA.

To define the project within a narrow range of specific operations and processes would be inconsistent with previous correspondence and discussions and inappropriate to the basic nature of the project scope and businesses of Frito-Lay. Even though the full project scope to develop the 100 acre, Highway 58 site has not changed, there have already been major changes in the products to be produced on-site, the method of production and the scheduling of the product production.

MARKET DRIVEN COMPANY

Frito-Lay is basically a marketing driven company that operates in a very competitive and dynamic marketplace nationwide. Its engineering and manufacturing units support the marketing strategies in both long and short term execution. In implementing the plant objectives that were used to describe the project, the Kern project site is intended to produce the type of product, in the necessary quantities and at a competitive price as dictated by marketing. The following are examples of how the original partial, preliminary project scope has changed to accommodate the marketing strategies.

> To provide the desired product mix from a marketing prospective, Phase I construction included a bakery in addition to the traditional salty snack facility. A new fruit snack food process was subsequently added to the project and granted approval by Kern County APCD.

To support sales forecasts in the major West Coast markets a second FRITOS\ brand corn chip line was added to the first phase construction plan in advance of its Phase II planned installation. A permit was also requested and approval granted by Kern County APCD for the second potato chip line before the plant even began operation in response to refined, projected market demand.

To achieve operating economies to meet sales cost objectives, a Cogeneration system was included in the initial construction phase and the starch dryer installed much earlier than anticipated. Both applications were granted approval by Kern County APCD.

GROWTH ORIENTED

Frito-Lay operates in one of the fastest growing grocery product areas, the salty snack food market. Salty snack food consumption has increased some 25 percent between 1980 and 1986. Frito-Lay, with 18 consecutive years of increased sales, has experienced a growth rate nearly one and one-half times the average of all grocery store products. Much of that growth has come from new products. From only two major brands in 1965, Frito-Lay now markets seven major product brands and is the market leader. The marketing, innovation and productivity that made this exceptional growth possible will be no less evident in the future. The Kern County project is situated with the potential to be in the forefront of the continued growth of Frito-Lay and the expanding snack food market.

WEST COAST LOCATION

Of the several Frito-Lay plants west of the Rocky Mountains, the Kern County facility is the only plant that is both centrally located and has "insurance" land and building space suitable for the new products and technologies projected in the marketing forecast. Any national new product roll-out would depend upon Kern to support expansion to the West Coast. Kern is also the logical location in which to continue development of the nontraditional (other than potato and corn chip) snack food lines because of access to the local agricultural products as identified in the plant objectives.

These new snack food processes, as well as existing product lines such as corn meal products, nuts, dips and meat snacks which were not included in the initial preliminary, phases of the project, are similar to the corn and potato chip processes already installed at the site. The emissions, air pollution control and environmental impact would also be similar to those for the existing salty snack sources.

PRODUCTION CAPACITY INCREASE OBJECTIVES

In addition to selective development of new product lines, growth in the existing core brands and reaching new market segments, one of the major strategies for growth at Frito-Lay, consistent with the Kern County project expansion originally envisioned by the planning documents, permit applications and EIR, is to "reduce costs through increased productivity, utilizing new technologies and manufacturing efficiencies." Basic corporate strategy now emphasizes the full, economical utilization of existing facilities, especially "high tech" plants such as Kern. This strategy implies the constant upgrading of processes in both efficiency and capacity, and in many cases potential increases in atmospheric emissions. Such actions require permit modifications for which emission offsets may be required. Anticipating this potential offset requirement, Frito-Lay acquired offsets from CCC for the Kern site sufficient to allow full project build-out.

PEPSICO, INC., SUBSIDIARY

Frito-Lay is only one of the major operating divisions of PepsiCo, Inc. Others include Taco Bell, Inc., Pizza Hut, Inc. and Kentucky Fried Chicken, Inc. It is economically imperative that Frito-Lay's food processing plants be sufficiently flexible to accommodate the food operations of any other PepsiCo division that would benefit from the centralized west coast location of kern County and its agricultural resources. Process operations of Frito-Lay and other PepsiCo operating divisions would fully meet the criteria described for future development at the 100 acre, highway 58 site in the EIR. Use of the CCC Emission Reduction Credits for such operations, would of course, remain the exclusive right of the Frito-Lay-PepsiCo family.

SUMMARY

The full project scope has naturally evolved in definition and timing, with specific process operations added, deleted and modified since the initial permit applications were made. There is no reason to anticipate that this on-going, dynamic planning will become static in the future since change and growth are basic to the Frito-Lay/Pepsico business segments. The original plan considered in the EIR contemplated limited expansion, the precise details of which were necessarily less well defined. The scope of the potential of Frito-Lay's expansion is not diminished and the potential benefit to both Frito-Lay and Kern County should not be limited. Frito-Lay needs the flexibility to meet the requirements of a fluctuating and competitive market-place within the framework of the stated intent of the EIR. The use of the CCC Emission Reductions gives Frito-Lay that flexibility in the very important air quality regulatory arena.

FRITO-LAY KERN COUNTY PROJECT

The Kern County facility is the most sophisticated, 'high tech' plant yet built by the PepsiCo subsidiary, Frito-Lay, Inc., anywhere in the world. Its initial cost was $55 million and the start-up operations employ over 525 Kern County residents. The facility is the first phase of a large food processing complex that is intended to be developed as the major production/distribution operation for the Pepsico family on the West Coast. The Kern County site was selected because of its strategic, central location, desirable site characteristics, and attractive potential for future expansion and full build-out.

The existing Frito-Lay salty snack plant occupies only 20-30 acres of a 100 acre core project site that is planned to be fully developed as identified in the planning documents and approvals for the project. The infrastructure (i.e., potable water system process and sanitary wastewater treatment and cogeneration system) to support the planned expansion is already in place.

PROJECT DESCRIPTION

The project is located in Kern County, California on approximately 634 acres located along Highway 58 west of Bakersfield. It consists of the 100 acre core portion of the site for which the Agricultural Preserve was cancelled and that was re-zoned M-2, P-D (Light Manufacturing - Precise Development) for a "food processing complex". An additional 200 acres was designated for land application of wastewater in the agricultural production of grasses and the remaining 300 plus acres of the site were left in the agricultural preserve.

Three of the objectives for locating the project in Kern County are the following:

* To utilize local agricultural products.
* To draw from the local labor force.
* "To better access the Southern California and Nevada market areas for finished production [sic] distribution."

The first phase of the project is the Frito-Lay salty snack manufacturing facility that has been constructed on 20-30 acres of the site and is now in operation. As part of this first phase, the infrastructure of water supply, electric power generation, wastewater treatment, drainage and roadways has been installed to support the future development of the full 100 acre site. Examples of the ultimate build-out and the environmental impacts of the completed project are presented in the various planning documents and permit applications.

FUTURE EXPANSION

The 100 acre, Highway 58 site and build-out of the project are defined most specifically in three documents. They are the Williamson Agricultural Preserve Land Use Contract Cancellation Application, General Plan Amendment Application and Environmental Impact Report.

The Final Environmental Impact Report (EIR) dated July 1, 1983 summarizes the entire project as one in which, "Development of the site will transform approximately 100 acres of undeveloped agricultural land into a food processing facility."

In the General Plan Amendment Application and associated request for a zoning change and submission of a Precise Development Plan, Frito-Lay described the phased development of the project as follows:

> "The ultimate configuration of the snack food and bakery facilities, regional warehouse and ancillary facilities (parking, etc.) will require a total area of 100 acres."

In justifying the cancellation of the Agricultural Preserve Land Use Contract as being in the public interest, one of only two reasons for which it can be cancelled, Frito-Lay described the site and project as:

> "...the location of a snack food production/bakery complex and a warehouse/distribution facility ... The ultimate configuration of this complex, including ..., etc., will require the full 100 acre portion of the parcel. No further development beyond that which is proposed within the 100 acre envelope is planned."
>
> "The production complex will ... provide over 1000 jobs (at full capacity) to Kern county residents."

ENVIRONMENTAL IMPACT OF PROJECT/FULL PROJECT CONSTRAINTS

A description of future expansion and full build-out of the phased project was presented in the EIR. The food processing/distribution complex was assumed to generate certain levels of traffic, employment, demands on public services and other environmental impacts. It was also analyzed to create certain benefits to the residents and economy of Kern County. Within the originally anticipated scope of these clearly identified constraints, the full project will be developed to the full extent of the 100 acre site potential.

The analysis in the EIR depicts a food production/distribution complex far larger than the present salty snack building, which occupies only 20-30 acres of the 100 acre site, that is now in place or proposed by currently approved APCD Authorities To Construct. The EIR describes the 100 acre, Highway 58 site project as having the following physical dimensions, environmental impacts and development constraints at ultimate build-out:

A complex of 750,000 square feet under roof on 100 acres of improved land eventually costing from $85-100 million.

Parking provided for 1194 cars and 150 tractor trailer trucks.

An approximate employment of over 1500 working around the clock, 5 days/week with weekends devoted to general sanitation activities necessary in a food processing operation.

Use of 1150 acre-feet/year of well water, with 53,000 gallons/day of sanitary sewage treated on-site and one million gallons/day of industrial wastewater treated by on-site land application in a 200 acre field producing alfalfa or other grasses

Use of 2.5 million KWHR/month of electricity and 72 million cubic feet/month of natural gas for the processes, three 60,000 PPH high pressure steam boilers and several smaller boilers. Cogeneration was a consideration to supply the electrical demand on-site.

Solid waste generation of 100 tons/day with over 25 tons/day going to local landfills and the remainder being reclaimed as by-product.

Consumption of 66,000 gallons/month of gasoline and 115,000 gallons/month of diesel fuel by employee and product distribution traffic in 2636 vehicle and 446 truck trips/day.

A four-fold increase in trains on the Buttonwillow branch of the Southern Pacific Railroad to two trains/day.

An increase in traffic noise on Highway 58 west of the site by 6.1 dBA and a train noise increases of 3 dBA.

Environmental quality defined in terms of fence-line air quality, odor detectability and community noise levels.

SUMMARY

The Frito-Lay Kern County project is the 100 acre, Highway 58 site that was re-zoned M-2, P-D and had a General Plan Amendment approved for the phased development of a major food processing/distribution complex. The full project will be expanded to the full potential of the 100 acre, Highway 58 site within the envelope of certain boundaries and constraints identified by the EIR. No further development beyond the 100 acre, Highway 58 site is planned as part of this project.

in the process vent is similar to that of the carbon black product being produced. This is because most if not all of the carbon black emitted is a result of small leaks in the product recovery bag filters". From this it can be concluded that particles emitted from the Continental Carbon facility in Bakersfield would fall in the range of 22--55 nm(mean particle size), the same particle size as the carbon black produced at the facility. Thus, all of the remaining particulate emission reductions represent actual PM10 emissions.

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
PB-273 068

Source Assessment Carbon Black Manufacture

Monsanto Research Corp., Dayton, Ohio

Prepared for

Industrial Environmental Research Lab., Research Triangle Park, N.C.

Oct 77

SECTION III

SOURCE DESCRIPTION

A. PRODUCT DESCRIPTION

Carbon blacks are essentially elemental carbon in the form of nearly spherical particles of colloidal dimensions. All carbon blacks possess similar properties, and the distinction between the various grades is one of degree rather than kind. In determining the utility of carbon blacks for commercial applications, the most important properties are: (1) particle size; (2) surface area; (3) extent of particle-to-particle association (structure); and (4) surface condition. The basic physical and chemical properties of carbon blacks are described below.

1. Physical Properties

a. Particle Size - The most important physical property of carbon black from the standpoint of commercial applications is particle size. The average particle size of unagglomerated oil furnace blacks ranges from 13 nm to 55 nm, as can be seen in Table 2.[2] For comparison, the properties of carbon blacks produced by the gas furnace, thermal, and

[2]Smith, W. R., and D. C. Bean. Carbon Black. In: Kirk-Othmer Encyclopedia of Chemical Technology, Second Edition, Vol. 4. John Wiley & Sons, Inc., New York, New York, 1964. pp. 243-282.

Table 2. TYPICAL PROPERTIES OF CARBON BLACKS[2]

Grade	Symbol[a]	Mean particle diameter, nm	Surface area N_2 adsorption, m^2/g	Oil absorption, cm^3/g	Nigrometer reading (unitless)	Volatile matter, %	pH	Benzene extract, %
Oil furnace blacks								
Super abrasion furnace	SAF	18 to 21	90 to 125	1.5	86	1.0	8 to 9	0.05
Intermediate super abrasion furnace	ISAF	22 to 25	115	1.3	88	1.0	8 to 9	0.05
Intermediate super abrasion furnace - low structure	ISAF-LS	20 to 23	110 to 130	0.8 to 0.9	87	1.5	8 to 9	0.05 to 0.10
Intermediate super abrasion furnace - high structure	ISAF-HS	22.5	110 to 120	1.4 to 1.6	99	1.5	8 to 9	0.05
High abrasion furnace	HAF	26 to 30	74 to 100	1.15	90	1.5	8 to 9	0.05
High abrasion furnace - low structure	HAF-LS	25 to 26.5	85 to 110	0.7 to 0.8	87	1.5	8 to 9	0.05
High abrasion furnace - high structure	HAF-HS	22 to 25	80	1.4 to 1.6	90	1.5	8 to 9	0.05
Fast extruding furnace	FEF	40 to 45	40 to 45	1.3 to 1.4	95	1.0	9	0.05
General purpose furnace	GPF	50 to 55	25 to 30	0.9	97	1.0	9	0.05
Conductive furnace	CF	21 to 29	125 to 205	1.3	86 to 93	1.5 to 2	8 to 9	0.06
Gas furnace blacks[b]								
Fine furnace	FF	40 to 50	40 to 50	0.9 to 1.1	90	1.0	8 to 9	0.05
High modulus furnace	HMF	60	30 to 40	0.85	95	1.0	8 to 9	0.10
Semireinforcing furnace	SRF	60 to 80	25 to 30	0.7 to 0.8	97	1.0	8 to 9	0.15
Thermal blacks								
Fine thermal	FT	180	13	0.3 to 0.5	107	0.5	9	1.75
Medium thermal	MT	470	7	0.3 to 0.5	110	0.5	8	0.3
Channel blacks[c]								
High color channel	HCC	9 to 14	400 to 1,000	2 to 4	58 to 69	5 to 16	3 to 4	None
Medium color channel	MCC	15 to 17	320 to 550	1.5	70 to 78	5 to 10	4 to 5	None
Regular color channel	RCC	22 to 29	100 to 140	1.1	80 to 85	5	5	None
Easy processing channel	EPC	29 to 30	100	1.0	85	5	5	None
Medium processing channel	MPC	25 to 28	110 to 120	1.0	83	5	5	None
Medium flow channel	MFC	23 to 25	200 to 210	1.1	80 to 83	7 to 8	4	None
Long flow channel	LFC	22 to 28	300 to 360	1.2	80 to 84	12	3.5	None

[a] ASTM numbers corresponding to the industry classification symbols are shown in Appendix D.

[b] Gas furnace blacks are no longer available. Similar blacks are now made by the oil furnace process (personal communication, H. J. Collyer, Cabot Corporation, Billerica, Massachusetts, 11 May 1977).

[c] Channel blacks are no longer produced domestically; however, they are still available on the international market (personal communication, H. J. Collyer, Cabot Corporation, Billerica, Massachusetts, 11 May 1977).

channel processes are also included in the table.[a] The nomenclature used in this table is that of the industry descriptive system, which is based on the manufacturing process and performance characteristics of the black. For example, semireinforcing furnace black (SRF) denotes a black with intermediate reinforcing properties in rubber that is produced by the furnace process. The American Society for Testing and Materials (ASTM) has also established a comprehensive nomenclature system for carbon blacks which is given in Appendix D.

Particle size is usually measured with an electron microscope, and the arithmetic mean diameter is reported. The particle sizes tend to be log-normally distributed, and the geometric standard deviation increases with mean particle size.[3,4] Typical particle size distributions are shown in Figure 2.

Particle size is of primary importance in determining the reinforcement properties of carbon blacks in rubber compounds. Small particle size blacks impart high tensile strength and abrasion resistance to rubber, but they are difficult to mix and process. The fully reinforcing blacks (SAF, ISAF, HAF), which provide maximum abrasion resistance (for example, in tire tread), range in particle size from about 18 nm to 30 nm.

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[a] Gas furnace blacks and, to a large extent, channel blacks have been replaced by similar blacks made by the oil furnace process. However, channel blacks are still used in some applications. For example, federal regulations specify the use of channel blacks in certain food processing operations.

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[3] Davidson, H. W., P. K. C. Wiggs, A. N. Churchouse, F. A. P. Maggs, and R. S. Bradley. Manufactured Carbon. Pergamon Press, New York, New York, 1968. pp. 1-55.

[4] Matsubayashi, E. Carbon Black. Sekiyu Gakkai Shi, 16(5):381-386, 1973.

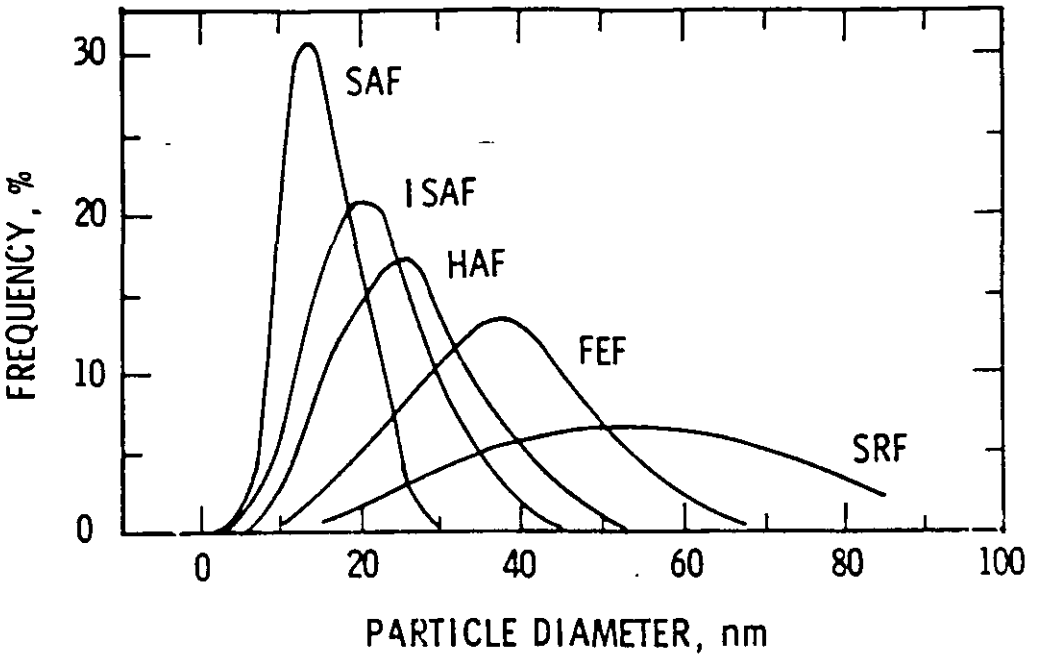

Figure 2. Carbon black particle size distributions for various industry classifications[4]

b. Surface Area - The external surface area of carbon black particles can be calculated from the particle diameter. The total area (internal plus external) is usually measured by gas-adsorption techniques, such as that of Brunauer, Emmett, and Teller (BET). The difference in these two values provides a measure of the internal (porous) surface area.

Low total surface area is desirable in rubber grade blacks since it results in low viscosity and low heat buildup during rubber processing. The high-color and long-flow ink blacks, on the other hand, are highly porous, having total surface areas two to three times greater than their external areas.

Typical specific total surface areas measured by nitrogen adsorption are given in Table 2 for the various grades of black. Some of the newer "improved" carbon blacks have

VII. CALCULATIONS CONT.:

B. SO2 Emissions Reductions

The quantity of SO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. This calculation is shown on page 14. The previously recognized amount was compared to actual emissions over the baseline method using AP-42 emission factors and by a method reported by I. Drogin in the Journal of the Air Pollution Control Association. These calculations of actual emissions indicate actual emissions are equivalent to the specific limiting condition (and may have exceeded the permit limitation). Therefore the previously recognized SO2 emissions may be considered actual emissions reductions. Basis and calculation of actual SO2 emissions is shown on pages 23-25.

For comparison purposes, Table III presents projected SO_2 emissions from the plant's process sources using two estimating methods. First, as concluded by I. Drogin and reported in his article published in the Journal of the Air Pollution Control Association, "...about 10% of the sulfur in the feedstock ends up in the black(finished product), with 90% going to the effluent." Under this scenario, emissions of sulfur compounds would approximate 3100 lbs/day (as S), based on an average production rate of 71.55 TPD, an average feedstock sulfur content of 1.36% and 394 gal. feedstock/ton of carbon black produced. Based on this method, SO_2 emissions could have been as high as 6200 lbs/day, not including the SO_2 contribution from the boilers which were fired on fuel oil (avg. 1.0%S) from 1977 on.

The other method used in projecting actual SO_2 emissions is AP-42 emission factors applied to the average production rate of 71.55 TPD. The results of this analysis are also shown in Table III. Briefly, the main process vent (reactor exhaust), when not controlled or equipped with a CO boiler or flare, emits significant quantities (>4000 lbs/day) of H_2S. The reactors at ConCarb, Bakersfield were not equipped with a CO boiler or flare. Portions of the reactor offgas were used as combustion fuel for the preheaters and dryers, resulting in the oxidation of this H_2S-rich stream. Actual H_2S/SO_2 emissions were therefore a function of the quantity of reactor offgas used as preheat and drying.

TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S})\ (64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /60	0 /4293
Dryer Vent	0.52/0	37.2/0
[illegible]	[illegible]	[illegible]
Boilers	142S (lbs/10^6 gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S)\ (0.50)\ (64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

Continental Carbon Company

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

10500 Richmond, P. O. Box 42817, Houston, Texas 77042, Telephone 713-978-5700 TWX 910-881-2636, Cable "CONCARB"

VII. CALCULATIONS CONT.:

C. NO2 Emissions Reductions

The quantity of NO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. This calculation is shown on page 14. The specific limiting conditions for the permit are the maximum legal emission from an operation and therefore do not quantify real and actual emissions over the baseline period. To quantify actual emissions of NO2 source test data for the stationary source from November 1978 was used with the actual carbon black production over the baseline period. The source test data is summarized on page 27. Actual emissions over the baseline period are:

Basis

Source test unit 1 NO2 emissions 28.96 lbs/hr
Source test unit 1 production rate 6381.7 lbs/hr or 76.56 tons/day
Average unit 1 production rate 35.73 tons/day (see page 13)

Source test unit 2 NO2 emissions 13.53 lbs/hr
Source test unit 2 production rate 4887.6 lbs/hr or 58.56 tons/day
Average unit 2 production rate 35.90 tons/day (see page 13)

Unit 1 Actual NO2 Emissions:

$$\frac{28.96 \text{ lb}}{\text{hr}} \times \frac{24\text{hr}}{\text{day}} \times \frac{35.73 \text{ tons/day average}}{76.56 \text{ tons/day test}} = 324.37 \text{ lbs/day}$$

Unit 2 Actual NO2 Emissions:

$$\frac{13.53 \text{ lb}}{\text{hr}} \times \frac{24\text{hr}}{\text{day}} \times \frac{35.90 \text{ tons/day average}}{58.56 \text{ tons/day test}} = 199.07 \text{ lbs/day}$$

Total NO2 Actual Emissions 324.37 + 199.07 = 523.44 lbs/day

NOx Specific Limiting Condition

Background

As required by the Kern Co. APCD, the specific limiting condition for NOx was used as the basis for establishing the quantity of NOx available for emission reduction credits.

Discussion

The specific limiting condition for NOx was based on stack test data, collected by Rockwell International in November, 1978. The supporting stack test data, together with emission rates identified in an October, 1979 Permit Analysis completed by Aerovironment, Inc. for Continental Carbon, are provided below.

Unit No.	Stack No.	Description	NOx Emission Rates lbs/hr Stack Test	Permit
1	1	Main Bagfilter	5.97	5.84
1	2	Main Bagfilter	6.10	5.96
1	3	Oil Preheater	1.30	1.36
1	4	Firebox Stack	13.80	13.75
1	5	Exhaust Bagfilter	1.79	1.79
2	6	Main Bagfilter	.317 Total Unit 1 28.96 lb./hr	.31
2	7	Main Bagfilter	.28	.27
2	8	Oil Preheater	.713	.74
2	9	Firebox Stack	9.69	10.21
2	10	Exhaust Bagfilter	2.53	2.61
-	11	Boiler #1	Total Unit 2 13.53 lb/hr	.65
-	12	Boiler #2	--	.65
		Total	42.49	44.14

Comparison of the two columns reveals little difference between tested levels and permitted levels. **It should be noted that since the boilers were not stack tested, there is no NOx contribution shown from these sources in the first column.**

VIII. COMPLIANCE:

A. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

The emission reductions were recognized in writing by the District in February 25, 1983. A copy of this correspondence is shown on pages 32-33 Kern County Air Pollution Control District Rule 210.3 - Emission Reductions Banking was adopted April 25, 1983 therefore, at the time the reductions were recognized the District did not have a banking rule. The reductions therefore satisfy the requirement that they were recognized in writing in a county that did not have a banking rule.

B. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable;

Actual Emissions Reductions

The Rule 230.1 definition of Actual Emissions Reductions states they are as defined in the District's New Source Review Rule. If the reductions are authorized by an Authority to Construct the adjustments made to the actual emissions reductions be as defined in the New and Modified Source Rule, shall be based on the rules, plans, workshop notices at the time the application for such Authority to Construct was deemed complete.

The Rule 220.1 definition of Actual Emissions Reductions states in part they are reductions of actual emissions from an emissions unit selected for emission offsets or banking, from the baseline period. Actual emission reductions shall be calculated pursuant to section V of this rule

The Rule 220.1 definition of Actual Emissions states they are measured or estimated emissions which most accurately represent the emissions from an emissions unit.

Rule 220.1 section V. - Calculations - states the following procedures shall be performed separately for each pollutant, and for each emissions unit or for a concurrent stationary source modification. All calculations shall be performed on a quarterly basis, unless specified otherwise.

For the shutdown of an emissions unit section V.E.2. of Rule 220.1 requires the actual emission reduction to be the Historic Actual Emissions prior to shutdown. Section V. also defines historic actual emissions as emissions having actually occurred based on source tests or calculated using actual fuel consumption or process weight, recognized emissions factors or other data approved by the Control Officer which most accurately represent the emissions during the baseline period.

VIII. COMPLIANCE:

The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.

The baseline period used in the calculations is the eight year period 1972-1979. This baseline period was used for the calculations because the NSR rule in effect at the time the reductions were authorized by Authority to Construct the NSR rule allowed an alternate baseline "Where the operation of a specific source has been significantly reduced during the previous three years the Control Officer may specify an averaging period emission rate which he determines provides an equitable emission base." (see page 29A). Because this baseline period was allow at the time the reductions were authorized by the issuance of Authorities to Construct for the Frito-Lay snack food facility no adjustment to baseline period is required. These reductions were calculated on an annual daily basis. Because this source is expected to ~~run rateably~~ over the year ~~and because an 8 year baseline was used~~ the daily reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1:

discuss not precluded by current rule

In addition the ~~8~~ not subject to seasonal variation emissions can be evenly distributed thus annual average

	Daily Emissions	Reference Page
PM10	560.1	8
SO2	2,768.3	22
NO2	523.4	26
VOC	4,776.6	8
CO	131,848.2	8

	Quarterly Emissions			
	First	Second	Third	Fourth
Days/Qtr	90	91	92	92
PM10	50,409	50,969	51,529	51,529
SO2	249,147	251,915	254,684	254,684
NO2	47,106	47,629	48,153	48,153
VOC	429,894	434,671	439,447	439,447
CO	11,866,338	11,998,186	12,130,034	12,130,034

As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.

B. For an existing source, the emissions of any air contaminant (or precursors, as defined in Section 3.C.2.) for which the area is designated nonattainment under Section 107 of the Clean Air Act, and any air contaminant emissions which are to be used as interpollutant tradeoffs (in accordance with Section 5.B.11) for air contaminants so designated shall be based on the actual operating conditions of the existing source averaged over the three consecutive years immediately preceeding the date of application, or such shorter period as may be applicable in cases where the existing source has not been in operation for three consecutive years, or is seasonal. However, emissions of such air contaminants from a fuel combustion source shall be based on the specific limiting conditions set forth in the existing source's Authority to Construct and Permit to Operate if (1) in the three consecutive years immediately preceding the date of application (or such shorter period as may be applicable) the source had been burning exclusively the dirtiest fuel allowed by the specific limiting conditions, and (2) the specific limiting conditions are representative of normal source operation in terms of operating hours, production rates, and the dirtiest fuel allowed. Where a source has not yet begun normal operation, emissions shall be based on the specific limiting conditions in the Authority to Construct. The emissions of any air contaminant other than those for which the area is designated nonattainment under Section 107 of the Clean Air Act shall be based on the specific limiting conditions set forth in the existing source's Authority to Construct permits and Permits to Operate, and where no such conditions are specified, or where no Authority to Construct was required, on the actual operating conditions as set forth above. Where the operation of a specific source has been significantly reduced during the previous three years, the Control Officer may specify an averaging period or emission rate which he determines provides an equitable emission base. If violations of laws, rules, regulations, permit conditions, or orders of the District, the Air Resources Board, or the Federal Environmental Protection Agency occurred during the period used to determine the operating conditions, then adjustments to the operating conditions shall be made to determine the emissions the existing source would have caused without such violations.

C. The cumulative net change in emissions from new or modified stationary sources which are not seasonal sources shall be determined using yearly emission profiles, or alternate method as specified by the Control Officer subject to consultation with the Executive Officer of the Air Resources Board.

Yearly emissions profiles for an existing or proposed stationary source or modification shall be established by plotting the daily emissions therefor in descending order. A separate profile shall be constructed for each pollutant.

VIII. COMPLIANCE:

Real

The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. A summary of these records is shown on page 12. The reductions therefore represent real emissions.

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. A table summarizing the initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions is shown on page 34. The remaining balance of emission reductions are surplus.

Permanent

All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.

Quantifiable

Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The calculation of emission reductions is shown in subsection VII. of this evaluation. The reductions therefore are quantifiable.

Enforceable

The permits to operate for the carbon black facility will be surrendered any new construction or operation of existing equipment at the site will require Authority to Construct pursuant to Rule 2010 and will be subject to new source review prior to construction or operation. The reductions are therefore enforceable.

VIII. COMPLIANCE:

C. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting remaining (surplus) emissions reductions are shown on page 34.

D. The reductions are included in or have been added to the 1987 emissions inventory.

Upon original approval of these emissions reductions the District required that these emissions be included in the current NAP inventory. To insure the proper amount of emissions is included District planning staff will be informed whenever all or a portion of these emissions are used as offsets for the Frito-Lay facility.

E. The banking application must be filed within 180 days of the date of rule adoption.

The application for emission reduction banking credits was submitted to the District March 17, 1992. This is within 180 days of the date of rule adoption.

F. Because these emission reductions can be validated as Actual Emission Reductions they qualify for ERC banking certificates that may be used in accordance with the requirements of Rule 220.1.

KERN UNTY AIR POLLUTION CONTROI ISTRICT

1601 "H" Street, Suite 250
Bakersfield, California-93301
Telephone (805) 861-3682

LEON M HEBERTSON, M.D.
Director of Public Health
Air Pollution Control Officer

February 25, 1983

Mr. H. C. Bradbury
Group Manager-Environmental Compliance
Frito-Lay, Inc.
P. O. Box 47250
Dallas, Texas 75247

Dear Mr. Bradbury:

Thank you for your recent letter in which you discuss the Continental Carbon Bakersfield facility's air contaminant emissions. The District has reviewed this facility's specific limiting conditions (contained in Permits to Operate), fuel oil and feedstock average sulfur content (0.8%), and applicable E.P.A. AP-42 emission factors. The following allowable emissions credits were determined from these data. Please note that the hydrocarbon emissions reflect a 50% reduction due to the exclusion of methane. (KCAPCD Rule 210.1 does not allow the use of methane as an emissions tradeoff because it is considered non-photochemically reactive.) The numbers below represent total facility emissions and are in units of lbm/day. Line #1 production rate was considered to be 35.73 tons/day and that of line #2 to be 35.90 tons/day.

Particulates	Carbon Monoxide	Hydrocarbons
560.1	131,848.2	2,388.3
Hydrogen Sulfide	**Oxides of Nitrogen**	**Sulfur Dioxide**
753.4	1,059.0	5,512.3

Even though some of these values are somewhat lower than summarized in your letter, it appears (on the basis of expected emissions summarized in your rough draft A to C applications package) that these emissions credits would provide adequate offsets (at a ratio of 1.2:1) for the Frito-Lay plant proposed for Kern County.

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Thank you for your cooperation. Should you have any questions, please telephone the Air Quality Control Division at (805) 861-3682.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Thomas Paxson, P.E., Manager
Engineering Evaluation Section

TP/dl

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FRITO-LAY EMISSION REDUCTION CREDITS

REFERENCE DOCUMENT	TSP = PM10 lbs/day	SO_2 lbs/day	H_2S lbs/day	NO_2 lbs/day	HC = VOC lbs/day	CO lbs/day
9/13/82 Letter to KCAPCD re: basis for ERC quantities	559.49	4773.6	3026.6	~~1059.4~~ 523.4	5117.3	141,239.7
12/22/82 F/L Letter to KCAPCD revising ERC quantities	560.1	4773.6	2825.3	~~1059.4~~ 523.4	4776.6	131,848.2
2/25/83(rev. 3/1/83) KCAPCD Letter to F/L revising ERC qtys.	560.1	4773.6	753.4	~~1059.4~~ 523.4	4776.6	131,848.2
Dedicated ERC's-- A to C's for Phase I	**(382.5)**	**(304.2)**	------	**(599.3)**	____	_____
6/21/88 KCAPCD Letter--verifying ERC balance	177.6	4469.4	753.4	~~460.1~~	4776.6	131,848.2
12/22/89 ERC Donation to KCAPCD	------	(2673.9)	(753.4)	------	(2221.4)	(130,848.2)
Reinstatement--ERC quantities from expired A to C's	99.93	1.2	-----	119.9	------	--------
ERC Balance--for F/L future use/banking certificate	**277.5**	**1796.7**	-----	~~580.0~~ 44.0	**2555.2**	**1000.0**

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IX. **RECOMMENDATION:**

Issue ERC banking certificated to Frito-Lay subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito-Lay snack foods processing plant at their present site and may not be sold or traded.

After public notice and review issue ERC Banking Certificates in the following amounts:

Pounds/Day From Page _____

PM10	SO2	NO2	VOC	CO
277.5	1796.7	44.0	2555.2	1000

Pounds/Quarter

	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	3,960	229,968	90,000
2nd Qt	25,252	163,500	4,004	232,523	91,000
3rd Qt	25,530	165,296	4,048	235,078	92,000
4th Qt	25,530	165,296	4,048	235,078	92,000

X. **BILLING INFORMATION**:

Engineering time 34.0 hrs @ 33.40/hr	= $1135.60
Clerical time 1.0 hrs @ 17.46/hr	= $ 17.46
Subtotal	$1153.06
less filing fee	$ 650.00
Total Fees Due	$ 503.06

ENGINEERING EVALUATION OF APPLICATIONS FOR AUTHORITY TO CONSTRUCT

BREAKDOWN OF PROCESSING TIME

Company Name: Lance Erickson

Company Number: 6026 Project Number: 920416

Project Description: Bank Previously Recognized Reductions

Processing Dates, Including Preliminaries: 4/24 4/23 4/24 4/27 6/18 6/22 7/23 7/24 7/27 8/12 8/13 8/14 8/19 8/20

PROCESSING ACTIVITY:	ACTIVITY TIME (HOURS):	INITAL:
Initial Contact: ___ telephone ___ in person		
Project Entry into System 36:	.5	JE
Preliminary Review:	6.5	JE
Organization/Familiarization:	8.0	JE
Project Description/Schematic/Equipment Listing:	1.0	JE
Listing of Applicable Rules:	-	
Design Review of Air Pollution Control Equipment:	-	
Calculation of Expected Emissions:	7.0	JE
Air Quality Impact Assessment Review (Modeling):	-	
Preparation of Emission Profiles:	-	
CEQA Review:	-	
Health Risk Assessment Review:	-	
Reworking of Application Due to Changes:	-	
Preparation of Rough Draft ~~A's to C~~ ERC	.5	JE
Preparation of Written Requests for Information:	1.0	JE
Telephone and Verbal Requests for Information:	1.0	JE
General Meetings with Applicant:	-	
System 36 Data Entry (Including Emissions):	.5	JE
Review Qualification for Banking :	8.0	JE
TOTAL TIME SPENT ON EVALUATION:	34.0	JE

Exhibit N

Powers Engineering

March 27, 2007

Ms. Gloria Smith
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080

Subject: Big West CFP DEIR Is Deficient in Its Failure to Analyze Air-Cooled Heat Exchanger as an Alternative to Cooling Tower

Dear Gloria:

This letter summarizes my assessment of the viability of using air-cooled heat exchanger technology to minimize or eliminate many of the impacts associated with the proposed use of cooling towers in the CSP. The Big West CFP DEIR is deficient in its failure to incorporate use of air-cooled heat exchangers to avoid the significant negative impacts associated with the use of cooling towers in the CFP.

The DEIR asserts (p. 3-17) that "*air-cooling has been maximized where possible*." This statement implies that Big West is aware that use of air-cooling is inherently preferable to wet cooling. Yet two cooling towers are specified for the CFP, the (1) Alky cooling tower and (2) the "General Purpose" cooling tower. There is no indication in the DEIR that any air cooling is included in the scope of the CFP, despite the claim that "*air-cooling has been maximized where possible*." No attempt is made in the DEIR to justify in any quantitative fashion why cooling towers were selected over air-cooled heat exchangers. Each cooling tower will emit 2.76 tons per year of VOC and 1.05 tons per year of PM_{10}.

These two cooling towers will add 1,100,000 gallons per day of consumptive water use and generate 350,000 gallons per day of wastewater that will be disposed of via injection wells. Approximately 60 percent of the CFP water demand of 2,080.7 acre-ft per year (AFY) is associated with the cooling towers. Over 80 percent of the wastewater to be treated in the CFP "additional wastewater treatment facility" will be generated in the cooling towers in the form of blowdown water.

Use of Air-Cooled Heat Exchanger Mitigates Consumptive Water Use, Wastewater Disposal, and Air Emissions Impacts of Proposed Wet Cooling Towers

Table 1 is a comparison of the annualized cost of proposed 15,000 gpm cooling tower(s) and air-cooled heat exchanger alternative. The ancillary systems that must be built and operated as a result of the wet cooling tower selection are also included in the wet cooling tower cost estimate.

These ancillary systems include groundwater pumping cost to provide make-up water to the cooling towers, construction cost of an additional wastewater treatment facility to treat cooling tower blowdown, and construction cost of three reinjection wells for disposal of treated cooling tower blowdown. None of these ancillary systems are necessary with the air-cooled heat exchanger. All detailed assumptions and supporting calculations for the basecase cooling tower and related ancillary systems are provided in attached Table A-1.

The annualized cost of the air-cooled heat exchanger with a 20 ^{o}F approach temperature is essentially the same as that of the cooling tower when all ancillary cooling tower systems are considered. All detailed assumptions and supporting calculations for the: 1) air-cooled heat exchanger with a 10 ^{o}F approach temperature, and 2) air-cooled heat exchanger with a 20 ^{o}F approach temperature are provided in attached Table A-2 and Table A-3, respectively.

Selection of the air-cooled heat exchanger eliminates all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} are reduced with the air-cooled heat exchanger even though power demand of the air-cooled heat exchanger is incrementally higher than that of the cooling tower. The reason for this is that cooling tower VOC and PM_{10} emissions from circulating process water, generated by off-gassing (VOC) and aerosol drift (PM_{10}), are generated at a higher rate than air emissions from an offsite power station generating power for the air-cooled heat exchanger fans. A small amount of NO_x emissions, 0.18 tons per year for the air-cooled heat exchanger with a 20 ^{o}F approach temperature, are generated by offsite power sources supplying power to the air-cooled heat exchanger fans.[1] There are no NO_x emissions associated with the cooling towers.

Table 1. Cost Comparison: Wet Cooling Tower and Air-Cooled Heat Exchanger

Alternative	Annualized cost, $/year	Consumptive water use, (gallons/day)	Wastewater discharge, (gallons/day)	Air emissions, (tons/year)	Power consumption, kw
Cooling tower, 15,000 gpm	840,725	1,100,000	350,000	VOC: 2.76 PM_{10}: 1.05	474
Air-cooled HX, 20 ^{o}F approach	837,937	0	0	VOC: 0.05 PM_{10}: 0.12 NO_x: 0.18	1,074
Air-cooled HX, 10 ^{o}F approach	1,261,625	0	0	VOC: 0.09 PM_{10}: 0.23 NO_x: 0.34	1,611

[1] Increase in power demand between the AA HX with 20 ^{o}F approach and the cooling tower is 0.6 MW. Air emissions from this 0.6 MW power demand are pro-rated from emission estimates for PG&E's Gateway Energy Center per March 26, 2007 report of Dr. Phyllis Fox. Gateway has a projected on-line date of June 2009 which coincides with the projected completion date of the CFP. Air emissions associated with the 0.6 MW increase in power demand for AA HX with 20 ^{o}F approach are: NO_x = 0.18 tpy, VOC = 0.05 tpy, and PM_{10} = 0.12 tpy. Air emissions associated with the 1.137 MW increase in power demand for AA HX with 10 ^{o}F approach are: NO_x = 0.34 tpy, VOC = 0.09 tpy, and PM_{10} = 0.23 tpy.

Air-cooled heat exchangers are very similar to automotive radiators. Large fans are used to draw air across tubes containing the water being cooled. The minimum outlet temperature achieved by an air-cooled heat exchanger is limited by the ambient air temperature. The more conservative the air-cooled heat exchanger design, the more it "approaches" the design ambient air temperature. That is why the air-cooled heat exchanger with a 10 ^{o}F approach temperature is considerably more costly and energy intensive than the air-cooled heat exchanger with a 20 ^{o}F approach temperature. A description of air-cooled heat exchanger technology and how it compares to wet cooling towers is provided in Attachment 1 (Ecodyne MRM technical bulletin).

Cooling towers rely primarily on evaporation of a small portion of the circulating water in the tower, in the range of 2 percent, to reduce water temperature. It is this evaporation that creates the need for large amounts of cooling tower make-up water, as well as the need to "blow down" a certain amount of circulating water to prevent the buildup of solids beyond acceptable levels.

The theoretical limit of the temperature reduction achievable in a cooling tower is the ambient "wet bulb" temperature. This is the air temperature reduction that would be reached if dry ambient air was completely saturated with moisture. This effect is demonstrated by misting systems that are used for ambient cooling along storefront walkways in hot desert climates. The wet bulb temperature is generally 10 to 20 ^{o}F below the dry ambient temperature on hot days. This is the reason that wet cooling systems are able to reach lower cooling water outlet temperatures on hot days than comparably sized air-cooled systems.

The air-cooled heat exchangers identified in Table 1 will measure either 40 feet by 252 feet (20 ^{o}F approach) or 40 feet by 378 feet (10 ^{o}F approach), depending on the level of conservatism desired in the air-cooled heat exchanger design. The primary function of the cooling tower or the air-cooled heat exchanger in this CFP application is heat rejection. Achieving a minimum cooling water outlet temperature is generally not as critical in refinery process equipment cooling applications as it is in power generation applications.[2]

The DEIR (p. 3-17) states the cooling towers will be located outside the process unit areas to minimize exposure to flammable material). This concern for flammability indicates it is anticipated that the cooling towers will be made of wood or fiberglass.[3] The cooling tower material of construction is not specified in the DEIR. Air-cooled heat exchangers are made of galvanized steel and would not be subject to siting constraints due to concerns over flammability.

[2] March 20, 2007 phone communication between B. Powers and J.A. Latimer, Puget Sound Refining Company and co-author of paper, *Optimizing Petroleum Refinery Cooling Water System*, 1999.
[3] January 13, 1993, standards interpretation, OSHA Standard 1910.106, *Fiberglass tanks for above and below ground storage of flammable and combustible liquids*. Fiberglass is considered to be a combustible material due to the flammability of the polyester resin used as a binder for the glass.

There is ample available space for installation of air-cooled heat exchanger(s) adjacent to the new CFP process units depicted in Figure 3-1, "Plot Plan."

Use of Air-Cooled Heat Exchangers Mitigates CFP Impacts on SWP Water

At maximum capacity, the CFP will require an additional 2,080.7 AFY of process water (DEIR, p. 4.5-29). Approximately 1,200 to 1,300 AFY of this additional water is associated with the consumptive water demand of the Alky and General Purpose cooling towers. See Table A-1. All of the replenishment water for this 1,200 to 1,300 AFY withdrawal will come from the State Water Project (SWP).

The CSP is located in Improvement District No. 4 (ID4). The ID4 was formed by the Kern County Water Association (KCWA) Board of Directors in 1971 to act as the wholesale provider of drinking water supply for portions of the metropolitan Bakersfield area. The ID4 has the ability to levy fees on groundwater pumping within its service area. The current fee schedule for 2005 would allow the ID4 to collect $30 per AFY for groundwater pumped from the refinery water supply aquifer (DEIR, p. 4.5-29).

The payment of groundwater pumping fees to the ID4 operational fund pays for the pumping of SWP water through the Cross Valley Canal. SWP water is banked within the groundwater recharge areas located approximately one mile southeast of the project. This replenishes the aquifer to reduce the impact of the CFP withdrawals on groundwater elevations.

Big West and the KCWA assume the SWP is an unlimited source of very inexpensive fresh water in identifying use of SWP water as adequate mitigation for aquifer withdrawals associated with the proposed cooling towers. Excessive transfers of Sacramento River Delta water via the SWP are an ongoing controversy in California.[4] KCWA treats SWP water as a free resource and will only charge Big West for the cost of pumping this water into the aquifer.

The fee of $30 per AF is an exceptionally low charge compared to what some other Southern California water users pay for SWP water. For example, the San Diego County Water Authority pays $427 per acre-foot to the Metropolitan Water District for a blend of raw water from the SWP and the Colorado River. See Attachments 2 and 3. If Big West were charged $427 per AF for 2,080.7 AF of aquifer recharge water from the SWP, the fee would be $888,459/yr, not $62,421/yr. A fee of this magnitude for SWP water would dramatically shift the economics in favor of air-cooled heat exchangers over cooling towers in the CSP.

Please feel free to call me at (619) 295-2072 or e-mail at bpowers@powersengineering.com if you have any questions about the contents of this letter.

[4] Los Angeles Times, *Another warning of Sacramento delta crisis*, February 8, 2007.

Best regards,

Bill Powers, P.E.

Bill Powers, P.E.

Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

tel: 619-295-2072
fax: 619-295-2073

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

Parameter	Assumed Value	Reference
Cooling tower circulation rate, gpm	15,000	DEIR. Appendix E, .pdf pages 57 and 58.
Cooling tower heat rejection rate, MMBtu/hr	150	A circulating cooling water range of 20 ^{o}F is assumed. Range is the cooling tower inlet/outlet temperature difference.
Installed cost cooling tower, $	1,300,000	Base 1999 cost for 15,000 gpm FRP cooling tower with 10 ^{o}F design approach temperature: EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 2, Table 2-13, *Estimated Capital Costs of Cooling Towers*. Capital cost of increase from 1999 to 2007 is 45%, per March 21, 2007 e-mail from J. Padilla of SPX Cooling Technologies citing a 40 to 50% increase in cooling tower cost from 1999 to 2007. The 45% increase brings cooling tower cost to $1,300,000.
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest is 0.0944. This factor is multiplied by the capital cost to derive the annual expense associated with the capital investment.
Annual expense on capital investment, $/yr	$122,720	0.0944 x $1,300,000 = $122,720/yr.
Cooling tower evaporation + drift rate, gpm	270	Approximately 1.8 percent of total cooling tower circulating water flow assuming a range of 20 ^{o}F. Source: Cooling Tower Fundamentals, 2nd Edition, Figure 40 – *Cycles of Concentration*, p. 31, 1998. Attachment A1.
Cooling tower blowdown rate to WWT, gpm	120	Assume 3 cycles of concentration is the design target for cooling tower, therefore blowdown rate is 0.8% of tower circulation rate. Source: Cooling Tower Fundamentals, 2nd Edition, Figure 40 – *Cycles of Concentration*, p. 31, 1998. Attachment A1.
Make-up cooling tower waterflow, gpm	390	Sum of evaporative, drift, and blowdown cooling tower losses. On continuous annual basis 390 gpm equals 631 AFY.
Depth to usable groundwater, feet	500	DEIR, p. 4.5-8. Water well construction and development reports filed with the California Division of Oil, Gas and Geothermal Resources are available for wells #4a and #4b developed in Area 1 of the refinery. Well #4a was drilled to a depth of 792 feet and perforated for water supply from 500 feet to 680 feet. Well #4b was filed on September 30, 1977, drilled to a depth of 775 feet, and perforated for water supply from 400 feet.

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

Equation for pump power required, hp	-	Pump motor hp = $\frac{\text{(gpm)(feet hydraulic head)}}{3{,}960\ (\eta_p)}$ Source: Mechanical Engineering Review Manual, 6th Edition, 1980. Chapter 6 – Hydraulic Machines, p. 6-30.
Pump efficiency, η_p	0.70	Default pump efficiency value.
Pump power required for supplying make-up water to cooling tower, hp	70	Groundwater is pumped from depth of 500 feet. Pump hp = $\frac{\text{(390 gpm)(500 feet head)}}{3{,}960\ (0.70)}$ = 70 hp
Distance from alky unit to additional WWT, feet	3,000	Review of plot plan, DEIR Figure 3-1.
Distance from additional WWT to injection wells, feet	500	Review of plot plan, DEIR Figure 3-1. This is the average distance from the additional WWT for the three new reinjection wells.
Friction loss in pipe, hydraulic feet per 1,000 feet	6.1	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, Table 3-17, *Cooling Water Pumping Head and Energy*. Assume mean pipe velocity of 7.7 feet/second and friction head loss rate of 6.1 feet per 1,000 feet of pipe.
Cooling tower to injection wells total pipe friction loss, hydraulic feet	21.4	Total pipe distance from cooling tower(s) to injection wells via the additional WWT is 3,500 feet on average. 6.1 feet/1,000 feet x 3,500 feet = 21.4 hydraulic feet. Wastewater flow is 60 gpm.
Pump power required for moving cooling tower blowdown through pipe to WWT and to injection wells, hp	1	Pipe friction loss hp requirement = $\frac{\text{(120 gpm)(21.4 feet head)}}{3{,}960\ (0.70)}$ = 1 hp
Cooling tower static hydraulic head, feet	25	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, p. 3-25.
Pump power required for circulating water through cooling tower, hp	135	Assume groundwater is pumped from depth of 250 feet as groundwater begins at 200 foot depth. Pump motor hp = $\frac{\text{(15,000 gpm)(25 feet)}}{3{,}960\ (0.70)}$ = 135 hp
Injection well pump motor power, hp	129	Average oilfield well motors in California, both producer and injection wells, is 43 hp. Source: *CEC-EPRI: Optimization of Electric Energy Consumption in Marginal California Oilfields*, Figure 4-7, Distribution of Motor Sizes, January 2003, p. 4-5.

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		The project will inject up to 10,000 barrels/day (DEIR, p. 4.5-33) of treated wastewater to a depth of approximately 4,000 feet (DEIR, p. 4.5-37)
Cooling tower fan power requirement, hp	300	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, Table 3-16, *Wet Tower Fan Power Energy Penalty*. Assume Case #1, cooling tower with design approach of 11 ^{o}F and design heat rejection of 150 MMBtu/hr.
Total power requirement for cooling tower, hp	635	70 hp + 1 hp + 135 hp + 129 hp + 300 hp = 635 hp
Total power requirement for cooling tower, kw	474	1 hp = 0.746 kw. Therefore, 635 hp = 474 kw
Wholesale cost of California electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html
Annual cost of electric power, $/yr	290,657	474 kw x $0.07/kwh x 8,760 hr/yr = $290,657/yr
O&M cost of wastewater treatment for cooling tower blowdown, $/1,000 gallons	2.00	EPA Control Cost Manual, 6th Edition, Chapter 2, *Cost Estimation: Concepts and Methodology*, 2002, p. 2-33. This is an estimated of fixed (labor) and variable (chemicals, energy, etc.) expenses, and does not include amortized treatment plant capital cost. See Attachment A2.
O&M cost of treating cooling tower blowdown, $/day	$346	$2.00/1,000 gallons x 120 gallons/minute x 60 minutes x 24 hours = $259/day
O&M cost of treating cooling tower blowdown, $/year	$126,290	$346/day x 365 day/year = $126,290/year
Charge to replenish aquifer under Flying J with State Water Project water, $/yr	$19,038	(DEIR, p. 4.5-29) Improvement District 4 (ID4) has the ability to levy fees on groundwater pumping within its service area. Based on recommendations made in the 2004, the current fee schedule for 2005 would allow the ID4 to collect $30 per AFY for groundwater pumped from the refinery water supply aquifer. The payment of groundwater pumping fees to the ID4 Operational Fund will pay for the pumping of State Water Project (SWP) water through the Cross Valley Canal. SWP water is banked within the groundwater recharge areas located approximately one mile southeast of the

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		project. At maximum capacity, the CFP will require an additional 2,080.7 acre-feet/day (AFY) of process water. At maximum production, the increased revenue to ID4 would be $62,421 per year based on the $30 per AF groundwater pumping fee. At a withdrawal rate of 390 gpm per cooling tower, the two cooling towers represent a maximum annual withdrawal of 1,261AFY, or 61% of the total withdrawal of 2,080.7 AFY. Therefore the aquifer recharge fee per cooling tower is ($62,421)(0.61/2) = $19,038/yr. It is of note that the charge of $30 per AFY is an exceptionally low charge compared to what some other Southern California water users pay for SWP water. For example, the San Diego County Water Authority pays $427 per acre-foot to the Metropolitan Water District for a blend of raw water from the SWP and the Colorado River. See Attachment 2. If Flying J were charged a comparable fee for 2,080.7 AFY of aquifer recharge water from the SWP, the fee would be $888,459/yr, not $62,421/yr.
Capital cost of groundwater pumping well(s)	?	No information is provided in the DEIR on the number of groundwater pumping wells that will be added to the facility to increase groundwater pumping by up to 2,080.7 AFY.
Capital cost of additional wastewater treatment facility, $	3,500,000	Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). 10,000 BPD is 420,000 gallons/day. Assume additional wastewater treatment facility is designed to treat 500,000 gallons/day. Source of cost estimate: SEWRPC Technical Report No. 43 – *State-of-the-Art of Water Supply Practices, Chapter 3: Surface Water Treatment Technologies,* revised November 28, 2006, *Table III-3: Construction Costs for Various Size Treatment Facilities*, $6.93 per gpd of capacity for 0.5 Mgd facilities. See Attachment A3. This estimate for facility designed to process surface or groundwater to drinking water level does not necessarily reflect the mix of treatment processes that will be used at the Flying J additional wastewater treatment facility. Flying J will be treating process water for onsite recycling or injection. However, no information is provided in

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		the DEIR on the water treatment processes that will be utilized.
Annualized capital cost of additional wastewater treatment facility, $	330,400	0.0944 x $3,500,000 = $330,4000/yr
Annualized capital cost of additional wastewater treatment facility per cooling tower, $	165,200	Total cooling tower blowdown is 345,600 gallons/day, equivalent to 8,229 AFY. Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). The cooling towers will generate for more than 80% of the wastewater to be treated. Assess entire capital cost of additional wastewater treatment facility to the cooling towers. Assess ½ of the capital cost of the additional wastewater treatment facility to each cooling tower.
Capital cost of three injection well(s)	2,475,000	Well depth is 4,000 feet (DEIR, p. 4.5-37). Estimated day rig rental rate in the Central Valley is $23,000/day. Turnkey daily drilling cost including auxiliaries is $50,000 to 60,000/day. 30-day timeline is reasonable drilling and completion schedule for 10,000-foot well. Source: phone communication between B. Powers and Don Cleveland, Nabors Drilling, Bakersfield, July 15, 2005. Assume for CFP that each injection well requires 15 days for drilling and completion. Turnkey daily cost is $55,000/day. Cost to drill each well is 15 days x $55,000/day = $825,000. Three (3) wells x $825,000/well = $2,475,000.
Annualized capital cost of reinjection wells, $/yr	$233,640	0.0944 x $2,475,000 = $233,640/yr
Annualized capital cost of reinjection wells per cooling tower, $/yr	$116,820	Blowdown from cooling towers that must be treated and reinjected is 240 gpm total, 120 gpm per cooling tower. Total cooling tower blowdown is 345,600 gallons/day, equivalent to 8,229 AFY. Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). Treated blowdown represents more than 80% of total water to be injected. Therefore all three reinjection wells are necessary for cooling tower blowdown disposal. Assess ½ the capital cost of the three reinjection wells to each cooling tower.
Wet cooling tower annualized direct and indirect total cost, $/year	**840,725**	$122,720/yr + $290,657/yr + $126,290/yr + $19,038/yr + $165,200/yr + $116,820 = $840,725/yr

Table A-2. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 10 °F Approach Temperature

Parameter	Assumed Value	Reference
Installed cost cooling tower, $	2,900,000	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME, 150 MMBtu/hr heat rejection, cooling water temperature reduction from 130 °F to 110 °F, 10 °F approach, 100 °F ambient design temperature. $2,430,000 equipment cost. See Attachments A4 and A5. Installation of modular AA HX units adds 10 to 25% to equipment cost, per March 23, 2007 e-mail from J. Schulz of SMITHCO/Anderson & Associates. Assume 20% installation multiplier. Installed cost is $2,430,000 + $486,000 = $2,914,000.
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest.
Annual payment on capital investment, $/yr	$273,760	0.0944 x $2,900,000 = $273,760/yr.
AA HX, number of modules ("bays")	27	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of bay, width feet x length feet	14 x 40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of AA HX array, width feet x length feet	378 x 40	27 bays would be positioned side-by-side to form continuous unit.
Number of fans per bay	2	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Power demand of each fan, hp	40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Design approach temperature, °F	10	The design temperature for Bakersfield is 100 °F. Source: Ecodyne, Weather Data Handbook, 1980, p. 12-13. AA HX is conservatively designed to reduce water outlet temperature to 110 °F at design ambient temperature on design 100 °F summer day.
Total HX fan power, hp	2,160	27 x 2 x 40 hp = 2,160 hp
Total HX fan power, kw	1,611	2,160 hp x 0.746 = 1,611 kw
Wholesale cost of electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html

Table A-2. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 10 °F Approach Temperature

Annual cost of AA HX electric power, $/yr	987,865	1,611 kw x $0.07/kwh x 8,760 hr/yr = $987,865/yr
10 °F approach AA HX annualized total cost, $/yr	**1,261,625**	$273,760/yr + $987,865/yr = $1,261,625/yr

Table A-3. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 20 °F Approach Temperature

Parameter	Assumed Value	Reference
Installed cost cooling tower, $	1,900,000	Increase of approach temperature from 10 °F to 20 °F, a cooling water temperature reduction from 140 °F to 120 °F, would reduce size and cost of AA HX by one-third, per March 21, 2007 phone conversation with Wes Cryster, application engineering manager, Ecodyne MRM. The 1/3 reduction in AA HX size and cost is applied to the basecase SMITHCO Engineering estimate. A 20 °F approach temperature is a common approach temperature for AA HX applications. See Attachment 1 (Ecodyne MRM brochure).
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest.
Annual payment on capital investment, $/yr	179,360	0.0944 x $1,900,000 = $179,360/yr.
AA HX, number of modules ("bays")	18	Adjusted (by B. Powers) March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of bay, width feet x length feet	14 x 40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of AA HX array, width feet x length feet	252 x 40	18 bays would be positioned side-by-side to form continuous unit.
Number of fans per bay	2	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Power demand of each fan, hp	40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Design approach temperature, °F	20	The design temperature for Bakersfield is 100 °F. Source: Ecodyne, Weather Data Handbook, 1980, p. 12-13. AA HX is designed to reduce water outlet temperature from 140 °F to 120 °F at design ambient temperature.
Total HX fan power, hp	1,440	18 x 2 x 40 hp = 1,440 hp
Total HX fan power, kw	1,074	1,440 hp x 0.746 = 1,074 kw
Wholesale cost of electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html

Table A-3. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 20 °F Approach Temperature

Annual cost of AA HX electric power, $/yr	658,577	1,074 kw x $0.07/kwh x 8,760 hr/yr = $658,577/yr
20 °F approach AA HX annualized total cost, $/yr	**837,937**	$179,360/yr + $658,577/yr = $837,937/yr

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
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AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
PROOF OF SERVICE
(Revised 05/10/2013)

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*Indicates Change

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COMMISSION DOCKET UNIT

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After docketing, the Docket Unit will provide a copy to the persons listed below. Do not send copies of documents to these persons unless specifically directed to do so.

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ANDREW McALLISTER
Commissioner and Associate Member

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Commissioners' Technical Adviser for Facility Siting

DECLARATION OF SERVICE

I, Andrea Sanchez, declare that on May 30, 2013, I served and filed copies of the attached Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903 dated May 30, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

The document has been sent to the other persons on the Service List above in the following manner:

(C*heck one*)

For service to all other parties and filing with the Docket Unit at the Energy Commission:

x I e-mailed the document to all e-mail addresses on the Service List above and personally delivered it or deposited it in the U.S. mail with first class postage to those persons noted above as "hard copy required"; **OR**

___ Instead of e-mailing the document, I personally delivered it or deposited it in the U.S. mail with first class postage to all of the persons on the Service List for whom a mailing address is given.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, and that I am over the age of 18 years.

Dated: May 30, 2013 /s/Andrea Sanchez

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MAY 30 2013
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

04-10-13.

Yo Graciela Madueña no he recibido ninguna notificación sobre la Planta que estará que se me tomara en cuenta y al no mandar notificaciones en Español se me esta discriminando por que soy hispana. Yo vivo en Buttonwillow y ya se siente en el ambiente con tanto polvo de trailer. Disculpen si no se expresarme pero esto me interesa por la salud de mi hijo que tiene "asma" les agradeceria que me mandaran información en español, muchas gracias.

Les agradeceria por toda la mayor información que me pudieran mandar. Gracias. Y desde hoy me opongo porque en realidad no se ni conozco nada de este Proyecto.

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SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

El fertilizante es muy peligroso al trabajar cerca. HECA guardara mas fertilizante en esta planta del Oeste de Texas. Los accidentes ocurren. Porfavor no permitan que construyan esa planta peligrosa cerca de mi trabajo.

Adriana Estracio MTZ

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SJVAPCD
Kern County

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Tengo miedo de conducir el tractor en la carretera con mas de 1000 camiones al dia. Es demasiado peligroso. Amonia y fertilizante son peligrosos. NO a HECA !!!

Ramiro Sandoval

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Josefina quiero información en español porque nunca e tenido información en mi idioma quiero que me informe de los peligros que puede afectar a nuestro niños.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Will Pollute Or Air.
Bad for people living in this Area
Also Bad for Kern County.
Will damage our crops
Will make the land worthless
Too much traffic.
Road cannot Handle the traffic.
Danger from fertilizer.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Taking Prime farmground for Industrial use.

TOO MUCH Pollution Air & Waste too much truck traffic causing more pollution.

We have the dirtiest air in the United States - no room for more pollution.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Will contaminate our crops. Then the crops will be worthless And we will lose our jobs. And possibly the entire Buttonwillow Area will be worthless

Too much POLLUCTION

Too much coal waste.

MAY 3 0 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Too much Pollution
worried about fertilizer
Explosion - unsafe

Coal dust a problem
too much truck or train traffic
unsafe roads.

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Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

I OPPOSE THE HECA PROJECT ON THE GROUNDS THAT IT WILL GREATLY INCREASE AIR POLLUTION IN AN AREA THAT ALREADY HAS THE WORST AIR POLLUTION IN THE NATION. I ALSO OPPOSE IT ON THE BASIS THAT THE PROJECT IS TO BE BUILT ON PRIME FARMLAND. FARMLAND IS A NATURAL RESOURCE WHICH IS LIKELY TO NEVER BE FARMED AGAIN ONCE INFRASTRUCTURE IS BUILT ON IT. PLEASE OPPOSE THIS PROJECT.

THANKS,

Brad Bunn

MAY 3 0 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

I AM Concerned with the air we breath in this area. WE already have some of the worst air quality in the nation and a project like this will only make it worse. PLEASE DENY THIS PROJECT. THANKS

Justin Bone

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Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

No More dirty air. Already we are worst in country. More trucks will make air even worse. No HECA Please

Ansel R. Caudin

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CVWRCB
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

As a Kern County Resident I oppose this project HECA will pollute our valley air and contribute to the Health Risk we deal with already.
I belive the Air district and All Government agency's should Stop adding to the accumulative impacts of pollution surrounding our communities Clean up put Hearth first above any Experimental

Sincerly
Ana Martinez

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo me llamo Rita Rios y tengo muchas dudas acerca de la planta de energia por que ay rumores que traera muchos problemas en los niños y adultos y contaminacion a nuestra ciudad. Nos quitara nuestra agua y la tranquilidad con la cantidad de camiones que entraran en nuestras calles y esos mismos camiones contaminaran el medio ambiente de nuestro alrededor estoy en des acuerdo.

08 APC 04
docket

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Ceili Mera. Me opongo a que la planta de electricidad este en mi ciudad.

Quiero que me informen en mi Idioma. acerca de este proclecto pero an informado pero en Ingles.

Nos an Dicho que la planta trabaja con material peligroso. para los que bibimos a qui.

~~RECEIVED~~
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Too Much Pollution
Use to much water.
Will Eventually use our ground water for drinking
Disposal of waste a BIG Problem.
Damage to our crops
Possibly loose our jobs if our crops become worthless.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

El fertilizante es muy peligroso al trabajar cerca. HECA guardara mas fertilizante en esta planta que en la planta del Oeste de Texas. Los accidentes ocurren. Porfavor no permitan que construyan esa planta peligrosa cerca de mi trabajo.

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MAY 30 20[illegible]

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Too Much Pollution
We have worst air in the state.
Will cause more illness. Asthma
lung problems. - may be cancer.

Too much waste from plant
will be disposed in our land fills.

where will we put all of the
waste after the land fills are
full.

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MAY 30 2013
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Salvador Martinez me opongo a que construllen esta planta por que no conosco de mueno de este planta y escucho comentarios que es muy peligroso para no sotros por que son quimicos peligrosos para mis hijos y por que el aire esta muy contaminado. Y 'gracias' espero que sean de los preocupaciones de la comunidad espero que no seaya esta construccion, tambien ay muchos niños en hermos de "asmá" y muchas otras enfermedades por el aire contaminado otra rason yo me opongo por que no conosco de este proyecto y ocupo de mas informacion para que agan este proyecto pongansse a pensar en los niños no el el dinero.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Laura Zamora, ME OPONGO aque se construya esta planta
* en primer lugar por que nunca e recivido ningun comentario sobre ello.
* en segundo lugar por la salud mia, de mis hijos y de la comunidad.
* en tercer lugar; por que este pueblito ya tiene una planta
* cuarto lugar por que hay riesgo que mi hija esta propensa a darle asma.
* quinto lugar el pueblo de Buttonwillow es chico y esta demasiado contaminado yo me ~~opone~~ OPONGO por LA SALUD DE MI FAMILIA Y LA DE ESTE PUEBLO A QUE NO SE REALICE ESTE PROYECTO.

GRACIAS.

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SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Nuestro aire es el peor del pais. Yo trabajo cerca de HECA. Los camiones que viajan a HECA haran el aire mas terrible. No es saludable para respirar esté aire ya. No permitan que ensucien el aire mas. No construyan HECA.

Apolinar Ramirez

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Albino Martinez me opongo por que el aire en esta comunidad de Bakersfield es muy contaminada y estoy preocupado con la comunidad y las familias que tenemos hijos chiquitos tambien trabajo en el campo y es muy peligroso con los troques que van andar traficando y ser muy peligroso manejar con los tractores en la carretera
Att albino martinez

Hydrogen Energy California (HECA) Project in Kern County

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SJVAPCD
Southern Region

Public Comments: Comentario Publico:

Necesitamos aire para nuestras familias. El carbon trasladado al condado de Kern es una terrible idea. Pero por seguro que no haya carbon hasta que el aire este lo sificientemente limpio para que la gente vuelva a quemar chimeneas.

Manuel Ramirez

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo, Victor Duarte estoy en contra sobre el projecto Hydrogen Energy California por las siguientes razones.

Opino que este projecto daniaria el medio ambiente. Los humos que desecharia este projecto en nuestro aire daniaria la agricultura. Tanbien pienso que con el tiempo se van a sentir los danos que llegaria a provocar este projecto.

Mi mayor preocupacion seria la contaminacion de nuestro aire que inhalamos dia a dia que nos va a danar hoy y en un futuro.

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SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Don't build HECA
The air is dusty and dirty in Buttonwillow.
Hundreds of more trucks a day will
make it harder to breath. Not healthy.

Albino Cavazos Jr.

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Central Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

A quien corresponda.

Por medio de este conducto hago presente mi inconformidad en el asentamiento y desarrollo del proyecto Hidrogen Energy California (HECA) en el condado de Kern.

Mi inconformidad está basada en los perjuicios locales y ambientales que traería consigo la ejecución de este proyecto, ya que ha sido muy evidente la presencia de enfermedades crónicas ocacionadas por la contaminación ambiental como lo son las enfermedades de caracter respiratorio (asma), además de los problemas de salud prenatal que el desarrollo de este proyecto traería consigo, pues es de todos el conocimiento que la presencia en abundancia de monóxido, dióxido y otras particulas contaminantes esparcidas en el aire que respiramos todos y en especial las mujeres en estado de embarazo trae como consecuencia el debilitamiento pulmonar de estos bebes por nacer y por ende problemas futuros en su sistema respiratorio.

Jose Manuel Martinez

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SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi familia tiene asma. No queremos mas aire sucio para que empeore el asma. Construyan HECA en algun otro lugar donde el aire no es tan malo.

Ignacio Fuentes

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MAY 30 2013
SVAQMD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

We Do not agree for the Hydrogen Energy Build in Kern County. It will double the Contamination in the air, My Son has astma not only him but other People in Kern County, We want a better healthier enviroment for us anel the residents of Kern County.

No estoy de acuerdo con la Planta de Hidrogeno Primero va ha contaminar nuestro aire las concecuencias Son atsma Para nuestros niños alergias Contaminacion Para nuestras frutas, Verduras tambien el agua no queremos esa planta en nuestro Condado de Por Si tenemos que cuidar nuestro aire y nosotros Somos los unicos afectados con esta Planta. NO estamos de acuerdo.

Josefa Rodriguez

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MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo maria cota me opongo a que instalen su planta de energia en la ciudad de buttonwillow. porque nunca se meha informado en mi ideoma sobre esta planta.

Yo sufro de alergias y se que esta planta afectara mi Salud.

Deseo tener mi familia y po'dria llegar a ber consecuencias grasias a esa planta.

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MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo oralia López me opongo Por el momento aque Istalen la planta de energia en mi ciudad ya que no me an informado de los riesgos que Coremos los que vivimos aki Yo no kiero que mis hijos ~~Po~~ Coman riesgos porque yo tengo una hija con asma.

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MAY 30 2013
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo me opongo rotundamente a esta planta por que no quiero que la gente incluyendome a mi estemos enfermos en nuestra comunidad.

Mi esposo ya tuvo la Valley fever por causa de el aire contaminado y no quiero mas quimicos que enfermen ala gente.

Ademas no conosco nada de este proyecto y no se me a notificado nada de esto.

Ana P. Candiola
306 Sudan ave.
Buttonwillow, CA
93206

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MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Me llamo Edna Aragüime. vivo en la comunidad de Buttonwillow y No me gustaría que pongan su planta cerca de nosotros, en nuestra comunidad nuestro aire no es tan saludable y no queremos que sea mas contaminado. no queremos que en un futuro nuestros hijos tengan problemas de salud y eso se puede evitar, evitando que instalen su planta cerca de nosotros.
Ademas quiero informarles que nunca nos informaron acerca de esta planta, nuestra comunidad ni siquiera sabe acerca de este proyecto. Queremos que informen con la verdad y en ESPAÑOL a todos los que vivimos aquí.
Por el momento me opongo a que instalen esta planta cerca de nosotros
No queremos esos carros atravesando por nuestras casas, contaminando nuestro aire, ni danando los cultivos que aquí se producen.

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Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

[redacted] Eloisa Sandoval Yo digo que Esta mal que agan eso porque estan infectando el aire del pueblo de parsi esta infectado y contaminado de los quimicos que usan los rancheros mas se va a infectar. Y los niños de parsi se enferma mas con eso se pueden enfermar. Y mas para los niños que tiene asma se puede enfermarse mas por el aire contaminado. Yo me opongo porque no e sido nada de informacion y no tiene por que estar asiendo fabricas y menos no Comunicando a la gente eso no esta bien Primero deben de ablar con la gente para avey si esta de acuerdo on no...!

muchas gracias

Eloisa Sandoval

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SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Yannet Montoya y vivo en la comunidad de Buttonwillow y yo digo que esta mal que dejen eso porque esta infectando el aire y puede provocar muchas enfermedades para las personas en personal a los mas viejitos y ninos. Yo quisiera que fueran mas cuidadosos con el aire que esta en nuestro medio ambiente y mas esta afectando a toda la gente que vivimos en esta comunidad de Buttonwillow de la manera mas atenta que por favor arreglen ese problema muchas gracias.

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Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Soy abitante de buttonwillow y tengo una niña con la spina dorsal por lo cual necesito ifformacioin sobre este proyecto de lo que pueda causar no estoy deacuendo en que nos Contaminaan el aire y Sobretodo. no deseamos quimicos que puedan agrabar la Salud de nuestros hijas de la manera mas atenta Ce les pde que nos comuniquen Sobre lo que nos pueda causar esta planta no podemos permitir algo que nos pueda Causar danos en de Salud a nuestro familia. Por esta razon me opongo a Cualquier proyecto que afecte ala Comunidad.

No deseamos quimicos serca de nuestra comunidad. grasia por su atencion.

RECEIVED
MAY 29 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

The San Joaquin Valley Air Control has not done the proper studies, research on public meetings to make a decision on approving this project.
I live in the community of Buttonwillow.
H.E.C.A has come into this community mis-representing the facts.
H.E.C.A said at the Board of Supervisors meeting that they did not know the route of travel for their trucks. They did know - they are not up front of this project.
Rio Bravo School district has not been notified and they too will be impacted by the trucks driving in front of their school.
Buttonwillow School will see heavy traffic due to this project.
Rails - No Way - Again not good for Rio Bravo School.

Kern County does not have to approve every power plant that comes along.

Take a stand and say no.

Marie Parsons

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

My name is Diana Connelly and I have lived in Bakersfield 30+ over 25 years.
I am very concerned that not enough research has been done regarding the environmental and sociological impacts of the HECA project.
Additionally, there has been almost no effort by HECA to inform the public of the impact of this project, most notably, the Spanish speaking population has not had meetings available in their language.
There are other alternatives available to meet our energy needs.

RECEIVED
MAY 30 2013
SJVAPCD
South Central

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Somos la familia Nieto
No Estamos deacuecdo con
proyecto por la contaminacion
Que Abra por Este proyecto

Rosendo Nieto

RECEIVED
MAY 30 2013
CEC/APPD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Oralia no estoy de acuerdo con lo de la planta que se kiere poner una de las cosas es porque yo tengo una hija con principios de asma esa es la razon gracias

Oralia Lopez

RECEIVED
MAY 30 2013
SJVAPCD

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi nombre es Josephina Rodriguez y yo me pongo porque no queremos Mas contaminacion en la comunidad y en las casas no dejamos nosotros ~~no~~ Ensender las chimineas por Que permiten Mas Contaminacion Con Esta planta de energia

Josefina Rodriguez

RECEIVED
MAY 30 2013
S.J.V.A.P.C.D.
San Joaquin Valley Air Pollution Control District

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

GUARANTEED JOBS ~~FROM~~ FOR BUTTONWILLOW COMMUNITY.
TRAINING FOR JOBS FOR HECA. DANIEL BRCIACA

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

My name is Jonathan Rodriguez I'am against it because I don't want more pollution is my home town.

Jonathan Rodriguez

RECEIVED
MAY 3 0 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

We are very concerned about how the project will affect our water. Jennifer Stuckman

RECEIVED
MAY 30 2013
CEC-RELAS
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

~~Me llamo~~ Me pongo porque va a traer mucha contaminacion y es males por la salud de los niños en la communidad.
Maria Perez

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

I don't want it. Too much pollution for this area. It is not needed. Very unnessary Bonnie Dedhozo
410 Cotton ave
Bak - CA 93206
Victor Zeltaro-No quiero que la Planta Por la contaminacion

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

JOSE R. GOMEZ. VIVO EN ESTA COMUNIDAD DE BUTTONWILLOW. NO ME GUSTARIA QUE NUESTRA COMUNIDAD SE CONVIRTIERA EN OTRA ESTADISTICA Y SE UBICADA POR EL ALTO INDICE DE NACIMIENTOS DE MALFORMACION, Y OTROS PROBLEMAS DE SALUD QUE ACARREAN ESTE TIPO DE PLANTAS A LAS COMUNIDADES EN LAS QUE SE ESTABLECEN ESTO NO ES LO QUE YO QUIERO PARA MI COMUNIDAD

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

My name is Joselynn Rodriguez I get buddy by many people. I get buddy and I don't want to get buddy. If someone can help me by not getting buddy then it will be okay to not get buddy.

X

Joselynn Rodriguez

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi nombre es Juan y yo me apongo porque mi prima tiene asma y no quiero que se enferme mas a se ponga mas peligro para su salud.

Juan Perez

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

no me gustaria que Pusieran esa Planta en Primer Lugar Por mis niños porque va a causar muchos Problemas de Salud Tejon Tribe.

RECEIVED
MAY 20 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi nombre Es Altagracia
Yo me opongo a Este projecto
de Esta planta de energia por qué
Existe mucha Contaminacion En mi
comunidad. X Altagracia Cisneros

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi Nombre es Maria Navarro S.
Este projecto va afectar Nuestra Salud
Me opongo a Este projecto

Maria Navarro

RECEIVED
MAY 30 2013
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

* Kenneth - Against it because of false advertising and exclude latino community.
* Juan Frias — Too many children with asma. (Not good!)

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

my name is Anayeli delarosa and I'm concerned of my little brother and sister, I don't want them to get sick or anything like that! thank you!!

x Anayeli D. L. Rosa

RECEIVED
MAY 3 0 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

I think the power plant would be beneficial because it would bring jobs to our community.

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Mi Nombre es Maria Garcia
Soy Madre de 5 Hijos y Me
preocupa la salud de Mis Hijos
por Este Projecto Que sola Contaminara
Nuestra ~~sal~~ Comunidad.

X María A Garcia

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo melida NO ESTOY de acuerdo que se
aga este Proyecto melida Rosa

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

I live and work on a farm in this area along with my family and am concerned with the air we breathe. This area already has poor air quality and this project will add to the level of pollution already here. New pollutants will be introduced including coal dust, transportation emissions in and out of the facility, and by-products from the plant itself.

Arturo Reyes

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

With Buttonwillow/Bakersfield among the worst air quality in the nation, I oppose this project because it will directly create greater negative air pollution where I live and work. Even though it may improve California air quality as a whole, I am being singled out to bear that health cost. Please deny this project.

Vicente Moreno

Rosa Mora

RECEIVED
MAY 30 2013
SJVAPCD
Central Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Too Much Pollution
unsafe for tupman people.
Bad for Buttonwillow
Toomuch waste from HECA Plant.

RECEIVED
MAY 30 2012
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Unsafe because of Fertilizer manufacturing an Storage.

Uses too much water.

Damages our crops.

Pollutes our air - makes it difficult to work.

RECEIVED
MAY 30 2013
S.J.V.A.P.C.D.
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Too much waste.
Fear of Fertilizer Explosion
Fear of Fertilizer contamination
Use too much of our water used
for farming

RECEIVED
MAY 3 0 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Yo Ana Canchola me opongo a que se construya la Planta de energia o Carbon (HECA) por que es un peligro para la salud de nuestras familias y para todos los que vivimos en esta area especialmente los niños que son nuestro futuro. Esta area ya esta bastante contaminada y tenemos muchos niños con asma y otras enfermedades por eso mi familia y yo nos oponemos rotundamente que se construya esa planta es muy peligrosa.

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

HECA is bad for our area because it will make the air more dirty. Using coal is not a good idea. Bringing trucks with coal will be more dirty air because it will use diesel trucks to bring in dirty coal.
No To HECA

Guadalupe Ramirez

RECEIVED
MAY 30 2013
SJVAPCD
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Chemical factories and chemicals at HECA are dangerous. Coal is dangerous and bad to breath when lots leaks out of trains. Too dangerous. Don't approve HECA

David Fuentes

RECEIVED
MAY 30 2013
Southern Region

Hydrogen Energy California (HECA) Project in Kern County

Public Comments: Comentario Publico:

Our air is worst air in the nation. HECA will make more dirty air and more trucks on roads will make more dirty air. I work here. NO HECA

Gerardo Martinez

APPENDIX N
Responses to Comments Received

DISTRICT'S RESPONSES TO COMMENTS RECEIVED DURING PRELIMINARY DETERMINATION OF COMPLIANCE (PDOC) COMMENT PERIOD:

CONCERNS ABOUT NON-AIR RELATED ISSUES

Comment 1:
Hydrogen Energy California (HECA) will use large amounts of water and will impact water quality.

The amount of waste created by the project could overburden existing landfills.

There is no need in Kern County for more electricity; where will the electricity produced go.

The project should not receive Federal funding from the Department of Energy.

The project should establish a bond to ensure that the any issues arising from the project in the future be mitigated.

There are concerns about the safety as a result of the facility due to chemical releases (including CO2) and possible explosions. Due to the recent explosion at the West, Texas fertilizer plant, there were concerns about fertilizer explosions and the impact it may have to nearby residents of Tupman and workers near the facility.

Additional truck traffic associated with the project will make it more dangerous to drive vehicles and tractors on the roads approaching the HECA facility, including along the route near Rio Bravo Greeley School on Highway 43. There were also concerns that the current roads will not be able to properly handle the extra traffic due to the project. There were also concerns about the expense the local government would incur to improve the roads to accommodate the project

Project uses unproven technology and should instead use alternative energy sources.

Some claim that the project may result in creation of additional jobs while others are concerned that the removal of farmland and possible damage of farmland would result in a reduction in farming jobs.

Response 1:
Please note that the District's role for this process is solely to determine if the project is expected to comply with air pollution laws and regulations. Our determination of compliance will be forwarded to the California Energy Commission (CEC) for their consideration in evaluating the project. Compliance with non-air related requirements, e.g. land use decisions, are not within the regulatory authority of the District.

All comments, including non-air related comments, received are included in the Final Determination of Compliance (FDOC) for CEC's review and consideration.

NOTIFICATION PROCESS/PUBLIC PARTICIPATION

Comment 2:
There was inadequate public notice for the project, especially for the Spanish speaking community.

Response 2:
On the contrary, the District undertook extraordinary and unprecedented efforts to ensure that the public, including Spanish speaking members of the public, were informed about the District's PDOC, and about their opportunities for participation and comment.

The District's first public hearing was held at the Bakersfield District office on April 2, 2013, in English, with Spanish translation services available. While no one requested Spanish language translation during that meeting, a request was made during that hearing, and subsequently, that we hold another public hearing targeting Spanish speakers. The District agreed to hold such a hearing, and took the extraordinary step to actually conduct the hearing in Spanish, with translation into English.

We created a Spanish-language notice for this hearing, announcing the date and location, and announcing that the hearing would be conducted in Spanish, with translation services available in English. We also published a Spanish language summary of the project, and included in this summary the information about the Spanish language hearing, and offered Spanish speakers the opportunity to speak directly, in Spanish, with the bilingual permitting engineer (Homero Ramirez) responsible for evaluating the HECA proposal, whether to provide verbal comments or ask questions. We also provided Mr. Ramirez's email address and US postal address.

We then posted the Spanish language notice (and its English translation) in public places throughout the towns of Buttonwillow and Tupman, published it in three local Spanish language periodicals, had it announced on four Spanish language radio stations (four times per day on each station, for five days prior to the hearing), posted it on the District's Spanish language webpage, and sent it to any person who had requested Spanish language notifications for the facility, for the region, or for the District, either by email or by US post, depending on their preference.

In addition, various community activists also widely spread the news, and offered dinner and drinks to any community members who would attend the Spanish language hearing. While we were not involved in this part of the effort, and could not be because of the coercive appearance of the free dinner offer, independent efforts to increase participation were appreciated.

On May 15, 2013, we held that second public hearing, conducting the entire presentation in Spanish (with English translation), including the display of Spanish language presentation slides and distribution of Spanish language handouts. We held the hearing in Buttonwillow rather than our District office to provide the greatest possible access of the local Spanish-speaking population.

We believe that this outreach was quite successful. We had nearly 100 attendees at the Spanish language hearing, and although many of them were attendees of the earlier English language hearing as well, there were several attendees who spoke Spanish during the hearing.

In summary, the District clearly provided ample opportunity for all interested parties to take part in the public process, and provided significant and extraordinary additional opportunities to Spanish speaking interested parties.

Comment 3:
One of the District's Spanish language announcements included an incorrect email address for the appropriate District staff to contact, limiting Spanish-speakers' ability to provide comment.

Response 3:
Following the first public hearing, the District posted an announcement in Spanish (and English) on the District website describing the project and announcing that its comment period would be extended. The notice also stated that questions, or verbal or written comments, could be directed to the District's Homero Ramirez by telephone, mail, or email, in Spanish or in English. The email was listed in two places on the notice, and in one of those places, it contained a typographical error: homero.ramriez@valleyair.org rather than the correct address homero.ramirez@valleyair.org. In the other location, on the same notice, the correct email was presented. In addition, the name Homero Ramirez was correctly spelled in two other locations on the notice, and the name "Ramirez" is common and the misspelling would have been readily recognized by most individuals.

Upon being informed of this error, the District immediately created a temporary email address that allowed emails sent to the incorrect address to be received by Mr. Ramirez.

In addition, the District specifically stated in the Spanish language notice that there were two additional ways to provide comments to the District, in Spanish. Mr. Ramirez's direct phone number was listed (and we specifically invited verbal comments or questions from Spanish speakers), and we listed Mr. Ramirez's US postal mailing address as well, and invited written comments in Spanish.

This combination of efforts provided Spanish speakers with several alternative ways to provide comments, and therefore we do not believe that anyone's ability to take part in the process was in significantly limited.

Further, the comment period was extended until May 30, 2013, allowing interested parties over 100 days to comment on the District's proposed action. With this extended comment period, any interested member of the public, including Spanish speakers, had ample opportunity to comment on the District's PDOC, well over the 30-day minimum required.

Comment 4:
The District should translate key District documents related to the HECA project into Spanish.

Response 4:
The District does not believe that it is necessary to translate all documents related to any particular permitting or DOC-issuance process, nor is it a responsible use of public funds. The District (as noted above) employed extraordinary efforts to reach out to the Spanish-speaking community and to provide them with many personal opportunities to learn about and comment on this proposal. For example, in Spanish-language notices regarding the HECA project we

offered personal access (direct phone line, email address, US mail address) to the bilingual District permitting engineer responsible for the analysis of the HECA facility, the person most knowledgeable about the project and a fluent Spanish speaker. We published several Spanish language notices, we posted them in public places in the vicinity of the proposed HECA facility and on our Spanish-language website, and we distributed the same information in local Spanish language print and radio media. We held a Spanish language hearing (translating the presentation slides and handouts into Spanish, and then verbally presenting it in Spanish), and accepted and responded to Spanish language comments and questions during that hearing. We accepted and responded to Spanish language questions and comments received in any format received, whether they were verbal or written, and whether received directly, by phone, by mail, or by email.

Finally, while we did translate a summary of the HECA project analysis into Spanish and made it readily available, and created all of the other opportunities for participation by Spanish speakers noted above, we do not believe that it is a reasonable use of District resources to translate the entire public record into Spanish, as has been suggested. For instance, our preliminary Determination of Compliance analysis was well over 600 pages long, and our final analysis is likely to exceed 800 pages. As an analysis of the potential workload involved, consider that just retyping these documents by a reasonably fast typist would take approximately 200 hours, or 5 person-weeks, before considering the additional time that Spanish translation would add. Spanish translation of highly technical documents such as these would multiply this number by many times. Given the other extraordinary opportunities the District provided for Spanish speakers to receive personal attention and explanation of the project and to take part in the process, based on the resource burden discussion above, we believe that no reasonable person could continue to expect Spanish translation of these documents.

Comment 5:
The District should have considered Environmental Justice concerns before issuing the PDOC.

Response 5:
The District considers environmental justice (EJ) issues in all of its permitting and determination of compliance actions, and has developed a comprehensive infrastructure to assure that interested members of EJ communities have ready access to take part in the District's public permitting processes. One only needs to read the above response to get a flavor of the District's efforts to incorporate EJ communities in the public process. In addition, because the majority of the environmental justice concerns expressed to the District involve impacts on communities that may have large Spanish-speaking populations, the District publishes all permitting and DOC notices in Spanish, and posts these notices on the District website. The District has also created a Spanish language "listserv", where individuals can sign up to receive all permitting and DOC notices, in Spanish, whether for a particular region of the District, or all notices for the entire District.

As an indication of our ongoing commitment to addressing environmental justice concerns, note that the District Governing Board adopted its first Environmental Justice Strategy many years ago, in 2007. This comprehensive policy serves as a roadmap to guide the District in integrating Environmental Justice principles and augmenting the steps already taken by the District in reaching out to the community. The Environmental Justice policy is available in English and Spanish at:

http://valleyair.org/Programs/EnvironmentalJustice/Amended%20EJ%20Strategy_June%202012.pdf and http://valleyair.org/Programs/EnvironmentalJustice/EJ%20Strategy-Spanish%20(amended%20062012).pdf

Comment 6:
Please provide a way for members of the public receive a copy of all public comments on the PDOC and District responses.

Response 6:
All those who provided their complete contact information in the public hearing sign in sheets will be notified how to view the District's Final Determination of Compliance, including all public comments received and the District's responses.

Please note that many comments received were concerning areas for which the District has no jurisdiction. Such comments (along with all other comments received) will be forwarded to the CEC as an attachment to the Districts FDOC.

Comment 7:
Please provide information on how members of the public can learn about future CEC meetings related to HECA

Response 7:
Information concerning future public meetings conducted by the CEC can be found online at http://www.energy.ca.gov/sitingcases/hydrogen_energy/notices/index.html .

Comment 8:
Are the public hearings being conducted by the District required by the California Environmental Quality Act (CEQA)?

Response 8:
The public hearings conducted by the District were held due to requests from the public, as a part of the District's Determination of Compliance process. These hearings were not required by CEQA.

TRANSPORTATION AND COAL DUST RELATED EMISSIONS

Comment 9:
Coal and coal dust can spill from rail cars, as near the coal transfer facility in Wasco, and cause health impacts to the public.

Response 9:
The District has regulatory authority over the air pollution issues for the dry material handling equipment at the site. Therefore the District can determine what requirements to impose for

those processes. The handling of the dry material will be in enclosed buildings, which are controlled by dust collectors and expected to result in no visible emissions.

District does not have authority over transportation of feedstocks to the facility. However, in order to better assure that no feedstock materials are released from its transportation and potentially cause a public nuisance the FDOC has includes conditions (see conditions in S-7616-17 and 18) that require that excess materials are removed from the exterior of the rail cars/truck trailers after unloading operations.

Comment 10:
There is concern about the emissions that the additional traffic associated with the project will produce.

Response 10:
The District has no direct authority to regulate the transportation emissions related to the project. However, as the United States Department of Energy (DOE) is providing funding to the project, the project constitutes a Federal action, and as such it is subject to District Rule 9110 (General Conformity) and Section 40 of the Code of Federal Regulation (CFR) Part 93 Subpart B, "Determining Conformity of Federal Actions to State or Federal Implementation Plans."

Under Rule 9110, Federal agencies (in this case the DOE) are required to make determinations that Federal Actions conform to approved State Implementation Plans (SIPs), as outlined in the subpart, before Federal Actions are taken, i.e. that the emission increases due to Federal Actions "conform" with approved SIPs and would not delay or impede the region's attainment. As is explained in the Determination of Compliance evaluation (Section VIII, Compliance, Rule 9110 discussion), one of the results of the General Conformity is that indirect emissions that exceed the conformity thresholds have to be mitigated. As is explained in that section, the indirect emissions are expected to exceed the conformity threshold for NOx due to construction and operation emissions, and the conformity threshold for VOC due to construction emissions.

To mitigate these transportation emissions, HECA entered into a mitigation agreement with the District in which funds provided by HECA will be used in the District's incentive programs to bring about emission reductions to mitigate the projects transportation emissions. See Mitigation Agreement in Appendix L.

Further, the CEC as part of its responsibilities under CEQA evaluates the impacts related to the project's transportation emissions, and must conclude that all significant transportation emissions are mitigated to the extent possible before they can license HECA.

Comment 11:
Please clarify if truck or rail transportation of feedstock result in greater emissions.

Response 11:
As shown in FDOC Appendix G, truck transportation will result in higher emissions than rail transportation.

The District verified that the transportation emissions estimated for the mitigation agreement to address transportation emissions are accurate and cover the truck transportation option, thereby conservatively mitigating the highest emissions option.

Comment 12:
There mitigation agreements between HECA and the District appear to be a way for applicant to "buy" approval from the District. There was a question as to whether this is the best policy to reduce emissions. There were also questions about the details of the mitigation agreements (including how the funds from the agreements would be used).

Response 12:
On the contrary, the two mitigation agreements will result in real emission reductions to completely mitigate the target emissions. The District acts only as the conduit for turning the developer's funds into emissions reductions by retrofitting or replacing polluting equipment. There are two mitigation agreements for the HECA project, one to mitigate emissions due to stationary source efficiency losses and the second to mitigate construction emissions and operational mobile source emissions to address general conformity compliance. The mitigation agreements are included as an attachment to the FDOC.

The first mitigation agreement mitigates the additional emissions associated with this loss in efficiency compared to a standard power plant project that uses a natural gas combustion turbine generator. The loss in efficiency will occur because a portion of the electricity produced by the facility will be used to power the carbon sequestration and the gasification portions of the project. Thus, the amount of NOx emitted per the amount of electricity generated to the electrical grid will be higher due to this parasitic load.

This mitigation agreement consists of a onetime payment to the District. This amount however will permanently mitigate the emissions because it will fund cleaner permanent replacement equipment.

The second mitigation agreement is intended to provide mitigation to satisfy the requirements of General Conformity and CEQA.

The funds generated from the mitigation agreements will directly fund emission reduction projects administered by the District. Please note that the mitigation agreements do not include the use of ERCs.

As specified in the mitigation agreements, funds from the mitigation agreements will be used preferentially for emission reduction projects near the project and in Kern County.

Since 1992, the District has been providing financial incentives for a variety of strategies to voluntarily reduce emissions and improve the quality of life for all Valley residents through these types of emission reduction projects. In total, the District has provided close to $500 million in incentives from a variety of local, state and federal sources. These efforts have resulted in a reduction of more than 98,000 tons of harmful emissions. Our incentive programs have become models for other air districts throughout California.

The District is regularly audited by independent outside agencies including professional accountancy corporations on behalf of the federal government, the California Air Resources Board, the California Department of Finance and the California Bureau of State Audits. These comprehensive and rigorous independent audits focus on every aspect of our incentive programs including our programmatic and fiscal controls. These audits are conducted to ensure that the public funds to which we have been entrusted are spent appropriately and in the manner in which they were intended. The District welcomes these opportunities to gain valuable feedback regarding our implementation of these critical programs.

Recently, the District's incentive programs were audited by the state Air Resources Board and the state Department of Finance. This audit included a thorough review of several of our largest and most complex incentive programs totaling more than $215 million over a four-year period.

Overall, the results of the audits confirmed that the District's incentive programs are fiscally sound and are "efficiently and effectively achieving their emission reduction objectives." ARB's audit report concluded that the District is meeting or exceeding all requirements for the expenditure of funds and commended the District for administering the Proposition 1B Lower Emission School Bus Program on behalf of 18 other local air districts.

Therefore, the proposed mitigation agreements have been shown to be effective methods of reducing emissions, and thus, are appropriate.

Comment 13:
The mitigation agreements should have been subject to public input and should not have been approved prior to the PDOC.

Response 13:
The mitigation agreements were subject to public comment at the April 18, 2013 Governing Board meeting. The governing board accepted public comments during the meeting before making their decision, which resulted in their approval of the mitigation agreements. In addition, as the District publicly stated during the April 18 Governing Board meeting and during the May 15 public hearing, if revisions to the mitigation agreements were necessary due to any comments received through May 30 (the end of the public comment period for the DOC), the mitigation agreements would go back to the Board for approval of the revised agreements.

Also note that the in order for the District to conclude that the project was in compliance Rule 9110 – General Conformity, the mitigation agreement regarding transportation emissions necessarily needed to be in place before the District could make its final decision. Therefore the order of events in the adoption of the mitigation agreements and approval of the DOC was appropriate and necessary.

Comment 14:
There was an inquiry about the life expectancy of the facility and the number of years of emissions that the mitigation agreement is based upon. If the mitigation agreement is only based on the first ten years, there was an inquiry as to how the emissions will be mitigated for the emissions in the years beyond the mitigated period.

Response 14:
The District understands that the life of the project is expected to be approximately 25 years. The mitigation agreement for indirect emissions is based on such emissions for a period 10 years. The funds obtained through the agreement will be used to fund emission reduction projects in which reductions are permanent. The reductions are permanent reductions because the emissions from the funded, replacement equipment are not expected to increase due continually stricter requirements. Even if the funded equipment is replaced, it is expected to be replaced with cleaner equipment. Therefore, the emissions are expected to be mitigated beyond the 10 year period of the mitigation agreement.

Comment 15:
Indirect emission estimates in mitigation agreement do not agree with indirect emission estimates provided by HECA.

Response 15:
The emission estimates used in the mitigation agreements were based on the most recent information available at the time. Please note that the mitigation agreement for indirect emissions requires that the actual indirect emissions be mitigated, and is not limited to the emission estimates included in the agreement.

PROJECT DESCRIPTION/EMISSION ESTIMATES

Comment 16:
The rationale used by for the ratio of PM2.5 to PM10 of 0.6:1 for the cooling tower emissions is flawed. At least one specific CEIDARS category could be more representative of cooling towers than the “unspecified” category, namely the PM Profile ID #200 for evaporation that provides a PM10 fraction of 0.96 and PM2.5 fraction of 0.925. If no specific particulate size fraction data reference for cooling towers is available, District should assume 100 percent of the PM10 is PM2.5.

Response 16:
The PM2.5 to PM10 ratio of 0.6:1 used was based on the best information available. Based on information provided in 08-AFC-8 for the original HECA proposal, the PM2.5 fraction of the PM emissions was determined to range from 0.333 to 0.555. Based on that information and engineering judgment, the applicant's proposal that all the PM is PM10 and that 60% of the PM10 is PM2.5 for its cooling towers was determined to be reasonable.

Comment 17:
Application support information for emissions estimates in PDOC were not part of application package; HAP emission calculations were not supported; AAQI/HRA report does not calculate emissions from subject equipment.

Response 17:
The PDOC constitutes the District’s review of HECA’s proposal and is not intended to capture the entirety of HECA’s application package. However, all application information is considered

public information (barring any trade secrets) and is available for review by the public, upon request.

Comment 18:
Emission calculations in PDOC are inconsistent with the emission estimates in HECA's 1/20/13 updated emissions data submitted to the CEC.

Response 18:
As noted, the emissions calculated in the PDOC were varied slightly from those in HECA's 1/20/13 updated emissions data. HECA has provided a further update to the emission estimates in their May 2013 comments on the PDOC. These emissions estimates varied vary slightly from those in the PDOC. The May 2013 updated emission estimates are used in the FDOC.

Comment 19:
The PDOC incorrectly references the installation of a future liquid ammonia loading facility.

Response 19:
The PDOC included a description of a future liquid ammonia loading facility only as to fully describe the proposed project. Ammonia loading operations are not subject to District permit requirements.

As HECA no longer proposes to install such a facility, this description will be removed in the FDOC. However, as the District has no requirements governing the loading of liquid ammonia, we cannot impose any requirements concerning the loading liquid ammonia nor can the District we prohibit the installation of any future liquid ammonia loading facility.

Comment 20:
The PDOC's Potential to Emit Estimates Are Based on Unsupported Assumptions

Response 20:
Emission estimates are based on reasonable assumptions and the best data available. The emission limits established in the PDOC are enforceable through numerous conditions that require monitoring, recordkeeping, and compliance testing to assure that the facility operates in compliance with the established emission limits.

Comment 21:
The Facility's Potential to Emit Is Underestimated and Emission Limits Are Not Adequately Enforced.

Response 21:
The PDOC includes limits on emissions during normal operation, during startup and shutdowns, and in reasonably expected upset conditions. It is not possible to estimate emissions from unplanned and unexpected operations as such emission estimates would be speculative. It is important to note that the facility must comply with the conditions of the PDOC, and any

operation outside of such conditions specified would constitute a violation of District requirements, so such speculative emissions estimates are unnecessary. However, we offer the following clarifications and additions in the FDOC:

Compliance with the NOx and CO emission limits (including the annual emission limits) for the gas turbine engine will be determined on an ongoing basis with a continuous emission monitor. Ongoing compliance with the annual NOx and CO emission limits in conjunction with throughput limits and annual source testing will ensure compliance with the emission limits for other pollutants.

The FDOC has been revised such that compliance with the VOC emission limit from the CO2 vent will be determined by recording the volume of gas vented in conjunction with periodic sampling and analysis of VOC constituents in the vent stream.

Short term startup/shutdown emissions from the auxiliary boiler are not expected to result in higher emissions from the boiler on a long term basis as the higher emissions during a startup and shutdown are mitigated by periods of no emissions when the unit is shut down.

The FDOC has been revised to include a quantification of emissions associated with a methanol storage tank and receiving and handling of fluxant materials.

Emissions Diesel storage tanks associated with the emergency IC engine/generator are exempt from permit pursuant to Rule 2020. As such, emissions were not quantified for the storage of diesel fuel.

In estimating fugitive VOC emissions from the process equipment the District relied on SOCMI fugitive emission factors and typical VOC content in the various process streams. The District concluded that the process equipment at HECA is more similar that is a SOCMI facility than that in a petroleum refinery. Additionally, the process streams at HECA typically include lower concentration VOC than either SOCMI facilities or petroleum refineries.

Finally, fugitive emissions from on-site traffic on roadways are not emission units or source operations as defined in Rules 2201 and 1020, respectively. Therefore, such emissions are not subject to the requirements of Rules 2201 or 2401. However, Regulation VIII – Fugitive PM10 Prohibitions apply to fugitive dust emissions from roads and onsite activities, and, therefore, applicable Reg. VIII conditions were included in the PDOC.

Comment 22:
The PDOC does not adequately restrict emissions of hazardous air pollutants to ensure synthetic minor source status

Response 22:

The PDOC requires that the permittee conduct an initial speciated HAP and total VOC source test to correlate the total HAPs emission rate and single highest HAP emission rate to the VOC mass emission rate. This correlation along with annual VOC source tests will be used on an annual basis to demonstrate compliance with the HAPs emissions limit of 25 tpy total or 10 tpy

for any single HAP. This testing and recordkeeping will demonstrate on an ongoing basis that the facility is a minor HAP source.

FDOC Appendix H has been revised to more fully describe the basis for our conclusion that the facility in a minor HAP source.

Comment 23:
The PDOC lacks enforceable emission limits/limits on feedstock quality

Response 23:
The PDOC includes enforceable emission limits on all source operations. It is not necessary to impose limits or requirements on the sources of the feedstock.

Annual emissions from CO2 vent are based on expected operating conditions during initial operation of the facility. As District rules rely on annual emission quantities to determine some requirements. There are no provisions in District rules to impose lower limits on annual emissions after a certain period of time after initial operation has elapsed.
Emissions rates from the cooling towers are based on the TDS content of the blowdown water, recirculation rate, and design specifications for the drift eliminator. These criteria are included as enforceable conditions in the PDOC.

The conditions for the nitric acid unit in the FDOC include limitations on daily and annual quantities of nitric acid produced and a NOx emission limit per ton of nitric acid produced. As such the FDOC includes enforceable conditions for the nitric acid unit.

The PDOC quantified emissions of PM10 and PM2.5 for each permit unit. The PDOC clearly indicated where, for a given permit unit, PM10 emissions are equal to PM2.5 emissions, and where PM2.5 emissions are a fraction of PM10 emissions. Further, the total PM2.5 (and PM10) emissions are below the PM2.5 major source threshold of 200,000 per year. Therefore the facility is not a new major source of PM2.5.

Finally, the PDOC requires that required records be maintained onsite for a period of at least five years. With this requirement, the District can gain access to such records at any time.

Comment 24:
The PDOC incorrectly excluded PM2.5 emissions from the Prevention of Significant Deterioration (PSD) analysis and related discussions.

Response 24:
Please note that PM2.5 is not included in the PSD analysis in those sections because the District is non-attainment for PM2.5. PSD applies to pollutants for which the District is in attainment of for unclassified pollutants, which includes the following pollutants: NO2 (as a primary pollutant), SO2 (as a primary pollutant), CO, PM, PM10, VOC, greenhouse gases (CO2, N2O, CH4, HFCs, PFCs, and SF6), lead, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur (including H2S), reduced sulfur compounds (including H2S). PM2.5 is analyzed under the more stringent requirements of Rule 2201 - New Source Review.

Comment 25:
Request that permit S-7616-21-0 contain a condition(s) that specifically requires operation of the syngas cleanup system to minimize emissions of volatile organic compounds, sulfur compounds, and mercury.

Response 25:
The District has added a condition to that unit that all equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere.

Comment 26:
The terms “equivalent equipment” and “alternate equipment” are used interchangeably and are not defined in permits such S-7616-25-0. A comment requested that the permits define these terms and require that the facility keep a log of each time the equipment is replaced.

Response 26:
In response to the comment, the wording in those permits has been changed to the term “alternate equivalent equipment”. The terms are in place in case the equipment identified in the application had changed or was no longer available at initial installation, but it is not intended to allow the permittee to exchange equipment after the initial installation without first submitting an application. The terms are defined by the set of conditions, which explains the process which must be satisfied prior to the District approving the “alternate equivalent equipment”.

Comment 27:
Permit S-7616-26-0 and the engineering evaluation should address what limits apply when hydrogen-rich fuel and natural gas are combusted together.

Response 27:
Please note that the combustion turbine generator will not be fired on either solely on hydrogen-rich syngas or solely natural gas, but not a mixture of both, and therefore such conditions are not necessary.

BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS

Comment 28:
Best Available Control Technology (BACT) for PM2.5 is required since PM2.5 is listed as an affected pollutant in Section 3.4.

Response 28:
For all sources except the cooling tower, PM10 emissions are equal to PM2.5 emissions. For the CTG BACT for PM2.5 is satisfied with the use of BACT for PM10.

Comment 29:
BACT analysis incorrectly does not consider clean fuel alternatives

Response 29:
District rules require that BACT be determined for the specific class and category of source (i.e. facility) being evaluated. The proposed HECA project is an integrated gasification combined cycle (IGCC) electrical generation facility that will utilize coal/coke as a feedstock, capture/sequester CO2, and include a fertilizer manufacturing facility.

Additionally, the HECA facility will demonstrate (with support from the U.S. Department of Energy) that IGCC technology using coal/coke feedstock can be utilized successfully with CO2 capture/sequestration. These feedstocks are widely available in the United States, and a demonstration by HECA that these materials can be used in a manner to produce electricity with low CO2 emissions is a primary objective of the HECA project.

As such, the class and category of source is an IGCC facility utilizing coal/coke feedstock with CO2 capture/sequestration.

Utilizing alternative feedstocks, such as natural gas or biomass, would result in a change in the class and category of source.

As BACT is required for a specific class and category of source, it is not appropriate to evaluate or require different feedstocks/processes that would result in a class and category of source.

Comment 30:
The PDOC's BACT Determinations do not address all pollutants subject to Rule 2201 requirements.

Response 30:
BACT is required for emission units pursuant to the requirements of Rules 2201 and 2410. The District's BACT requirements in Rule 2201 are equivalent to Federal LAER requirements. District BACT requirements are determined using a five step process - 1) identify all possible control measures, 2) eliminate technologically infeasible options, 3) rank remaining control techniques, 4) perform a cost effectiveness analysis, and 5) select BACT.

Pursuant to Rule 2201 BACT is required for emission units with emissions greater than 2 lb/day or when the emission unit is part of a new major source or a major modification. For HECA, BACT is required for PM10, NOx, VOC, SOx, and CO.

Please note that pursuant to the definition of emission unit and source operation in Rules 2201 and 1020, respectively, control devices are not emission units. Therefore, ammonia emissions due the use of selective catalytic reduction and SOx emissions due to the use of the sulfur recovery tail gas treatment unit are not subject to BACT requirements.

The BACT requirements established in the PDOC for PM10, NOx, VOC, SOx, and CO serve to satisfy the requirements for BACT for all pollutants emitted by the facility.

Comment 31:
The PDOC's BACT determination does not consider the novel nature of the HECA facility.

Response 31:
District rules require that certain new and modified emission units be equipped with BACT. In determining BACT requirements the District relies on established BACT guidelines to provide certainty to permit applicants and provide a consistent method in evaluating BACT requirements. This results in consistent BACT requirements being established for various facilities in the District.

Comment 32:
BACT Determination for Cooling Towers should consider address dry cooling

Response 32:
While we believe the BACT determination we conducted in the PDOC for the cooling towers satisfies District rule requirements, the FDOC includes a revised BACT determination in which we evaluated dry cooling. Please note that to our knowledge dry cooling has not been achieved in practice for IGCC facilities. The FDOC contains a screening level BACT cost effectiveness analysis for dry cooling. This analysis demonstrates that dry cooling is not cost effective for the proposed facility and therefore cannot be required as BACT.

Comment 33:
BACT Determination for Flares Is Deficient

Response 33:
The flares at the proposed facility will typically be operated during startup and shutdown activities to destroy syngas with a very low VOC content. There is not expected to be routine flaring of gasses, i.e. no routine venting of low volume gasses, as in the case in the refining industry. For this reason, a flare gas recovery system is not technologically feasible.

Additionally, due to the need for the flares to safely dispose of large volumes of gasses during process startup and shutdown, use of a ground level flare is not technologically feasible due to inherent safety concerns with flaring large volumes of gas at ground level. An elevated flare is inherently safer than a ground level flare. The safe disposal of gasses is the primary function of the flares.

Comment 34:
BACT Determination for Fugitive Equipment Leaks Is Deficient.

Response 34:
The Top-Down BACT Analysis for fugitive emissions used the District's BACT guidelines for valves, connectors, and pump and compressor seals at chemical plants, because the proposed facility most closely resembles a chemical plant, and is appropriate. Use of established BACT guidelines provides for a consistent application of BACT requirements. These BACT guidelines require the implementation of a leak inspection and maintenance program pursuant to District Rule 4455. The PDOC conditions for these systems contain requirements for leak detection and repair equivalent to those in Rule 4455.

Comment 35:
BACT determination for greenhouse gas emissions for power block is deficient

Response 35:
The BACT determination for GHG emissions is appropriate and includes enforceable requirements that require that CO2 produced in the gasifier be utilized in a nearby enhanced oil recovery operation in accordance with a monitoring, reporting, and verification plan approved by DOGGR. Venting of CO2 will be limited by condition in the PDOC such that at least 90% of the CO2 generated is used in the enhanced oil recovery operation and sequestered.

Comment 36:
The combustion turbine generator (CTG) for the HECA project is limited to 2.5 ppm-NOx, but there are other project examples that have combustion turbine generators limited to 2.0 ppm-NOx.

Response 36:
The Best Available Control Technology (BACT) analysis in the PDOC indicates a 2.0 ppmv-NOx limit was determined technologically infeasible for the proposed combustion turbine generator. Since the combustion turbine generator will fire primarily on hydrogen-rich fuel, the turbine will be required to be equipped with a diffusion-type combustor, as opposed to dry-low NOx (DLN) combustor technology, which is typically installed in modern combined-cycle units firing on natural gas fuel. With a diffusion-type combustor, NOx emissions will be controlled with diluent injection of nitrogen and a selective catalytic reduction (SCR) system. Available DLN combustor technologies are designed for natural gas (methane-based) fuels, and this type of technology is not technically practical for syngas (hydrogen/CO-based) fuels used by the proposed combustion turbine due to the potential for explosion hazard in the combustion section due primarily to the high hydrogen content of the syngas.

As the BACT discussion indicates, there are no known DLN combustors for turbines fueled by petroleum coke or coal-derived syngas. Therefore, the best guaranteed control level available for the proposed operation was determined to be 2.5 ppmv-NOx.

Comment 37:
It is not possible to verify the validity of the determination that the best guaranteed control level available is indeed 2.5 ppmv-NOx because the CTG's uncontrolled emission level had been redacted as confidential information.

Response 37:
Please note that the applicant has presented the necessary justification as required by District Rule 1030 (Confidential Information) to designate the uncontrolled CTG emission rate as confidential.

Please note that per Rule 1030 Section 6.0 such information designated as confidential can only be released by the District to: the California Air Resource Board, which protects trade secrets as provided in Section 62547 of the Government Code and Sections 91000 to 91022 of the California Administrative Code, Title 17; and the Federal Environmental Protection Agency,

which protects trade secrets as provided in Section 114C of the Clean Air Act and in 40 CFR, Chapter 1, Part 2.

Comment 38:
It was recommended that in the future, where applicable, that a comparison of the applicable standard under 40 CFR parts 60 and 61 to the proposed BACT determination(s) be included in the District's BACT analysis for PSD projects.

Response 38:

The District will follow EPA's recommendation for future PSD projects.

EMISSION OFFSETS

Comment 39:
Section 4.8.1 of Rule 2201 requires a volatile organic compound (VOC) distance offset ratio of 1.5:1, not 1.3:1.

Response 39:
The FDOC includes a corrected distance offset ratio for the VOC emissions of 1.5:1 as required in Rule 2201 Section 4.8.1.

Comment 40:
Use of Emission Reduction Credits should not be allowed as their use will not mitigate the projects emissions.

Response 40:
Rule 2201 (New and Modified Stationary Source Review Rule) requires those sources with Stationary Source Potential to Emit (SSPE) which result in levels greater than the emission threshold to provide emission offsets as prescribed by that rule. Those emissions are offset in the form of Emission Reduction Credit (ERC) certificates, and the emissions associated with this project are required to be offset according to the requirements of this rule as demonstrated in the Compliance section (VIII.) of the Determination of Compliance.

Emission reduction credits are recognized by all air districts in California, the state Air Resources Board, and federal EPA as real mitigation for emissions increases when appropriate safeguards are employed. The ERC bank allows facilities that make voluntary emission reductions to store ERCs for later use as mitigation, or "offsets," of emissions increases. Facilities proposing increases in emissions may have to offset their emission increases by purchasing ERCs from facilities that have made voluntary emissions reductions. The ERC program provides incentives to facilities to find improvements that will reduce their emissions to generate such credits.

The following safeguards are in place in the San Joaquin Valley to assure that the use of ERCs will provide real benefit to air quality:

- Credits are issued for actual emissions reductions that go beyond that which is required by law, with no credit available for reducing permitted emissions,
- Reductions are discounted for any requirements that currently apply
- Reductions are discounted for any anticipated future requirements,
- Ten percent of the reductions are confiscated and retired permanently,
- The ERCs are incorporated in the Region's growth factors as emissions in the air attainment plans and associated emissions inventories. The attainment plans then provide for real-time mitigation to ensure contemporaneous air quality benefit, regardless of the date the credits were banked.
- Comprehensive annual accounting and reporting document and verify real-time benefit to air quality.

It is important to note that Rule 2201 section 7.0 includes a requirement that the District demonstrate on an annual basis that the offset requirements of Rule 2201 are equivalent to the quantity of offsets that would be required by a Federal only non-attainment New Source review program. These provisions have been in place since 2001. Since that time the District, every year, has demonstrated offset equivalency with Federal New source review offset requirements.

Comment 41:
New major sources cannot use ERCs until there are approved plans in place for all NAAQS that appropriately account for ERCs in Reasonable Further Progress (RFP) and the attainment demonstrations.

Response 41:
The District has two approved plans in place. EPA approved the District's state implementation plan for the 1997 8-hour ozone standard (the "2007 Ozone Plan") on March 1, 2012 (77 FR 12652, http://www.gpo.gov/fdsys/pkg/FR-2012-03-01/pdf/2012-4674.pdf), and EPA approved all but one minor element (which will soon be corrected) of the District's SIP for the 1997 PM2.5 standard (the "2008 PM2.5 Plan") on November 9, 2011 (76 FR 69896, http://www.gpo.gov/fdsys/pkg/FR-2011-11-09/pdf/2011-27232.pdf). EPA has not acted on the District's attainment plan for the 2006 PM2.5 standard, and that the District is in the process of amending its plan for the revoked 1-hour ozone standard. However, these pending attainment plans do not affect the continued use of ERCs. Additionally, EPA has approved Rule 2201 – New and Modified Stationary source review which specifically allows use of ERCs for provide emission offsets.

As shown above, the District has an EPA approved attainment plan in place. As such, new major sources can use ERCs to provide offsets.

Comment 42:
HECA's VOC ERCs are greater than 30 years old and are otherwise not valid.

Response 42:
Rule 2201 allows any District issued ERCs to be used as emission offsets. There are no provisions in the rule that address when the emission reduction that generated ERCs occurred. It is important to note that Rule 2201 section 7.0 includes a requirement that the District demonstrate on an annual basis that the offset requirements of Rule 2201 are equivalent to the

quantity of offsets that would be required by a Federal only non-attainment New Source review program. These provisions have been in place since 2001. Since that time the District, every year, has demonstrated offset equivalency with Federal New source review offset requirements.

Further, the subject VOC ERCs were determined to meet all applicable requirements for emission reduction credit banking when they were originally issued. Prior to issuance of the ERCs, our preliminary decision was subject to public comment, including comment by EPA and CARB. The District considered all comments received prior to our decision to issue the ERCs. The subject VOC ERCs are valid for use.

Comment 43:
Proposal to use SOx ERCs to offset PM10 emission increases does not consider the difference in location between the location of the ERCs and the location of the emission increases and does not consider the different PM10 formation rates during summer and winter.

Response 43:
Rule 2201 imposes a distance offset ratio for uses of ERCs to offset emission increases. As the location of the SOX ERCs is greater than 15 miles from the proposed facility, the appropriate distance offset ratio for PM10 emission increases is 1.5:1. As such, the difference in location between the location where the emission reductions occurred and the location of the proposed emission increases was is accounted for in the PDOC.

The District's currently accepted interpollutant ratio between SOx and PM10 is 1:1. This interpollutant ratio was developed using elements form the District's 2008 PM2.5 attainment plan. In fact the analysis performed supported an interpollutant ratio of less than 1:1. However to be conservative and consistent with the requirements of Rule 2201, the interpollutant ratio between SOx and PM10 has been set at 1:1.

Comment 44:
Proposed use of Sox ERCs to provide PM2.5 offsets are not adequate to offset projects emissions. Secondary PM2.5 emissions are not modeled or offset.

Response 44:
PM10 and PM2.5 emission increases are being offset using SOx as interpollutant offsets. The proposed Sox ERCs were been quantified pursuant to District rules and the preliminary decision to issue such ERCs was subject to public comment. All comments received were considered prior to issuance of the subject ERCs. As such, the ERCs are valid for use.

The SOx/PM2.5 interpollutant ratio used of 1:1 is the most appropriate currently approved ratio available. The SOx/PM2.5 ratio included in the District's 2012 PM2.5 attainment plan of 4.1:1 is not yet valid as this plan has not yet been approved by EPA, with the 2012 PM2.5 attainment plan.

Separately, SOx and NOx are the only identified PM2.5 precursors in Rule 2201; VOC and ammonia are not identified as PM2.5 precursors. SOx and NOx emissions from the project are being offset at a distance offset ratio of 1.5:1 pursuant to the requirements of Rule 2201. As all direct PM2.5 emissions and PM2.5 precursor emissions from the project are being fully offset,

there is not expected to be an impact on ambient PM2.5 concentrations as a result of the project.

Comment 45:
Copies of the ERCs and ERC evaluations should be made available.

Response 45:
The District has made available in the public notice section of its website the copies of the ERC certificates and the project evaluations which resulted in these certificates. The information is specifically available at: http://www.valleyair.org/notices/Docs/2013/02-07-13%20(S-1121903)/Proposed-ERCs-and-original-emission-reduction-application-reviews.pdf.

Comment 46:
HECA should provide excess offsets to allow for more burn days in the Valley.

Response 46:
The District does not have the authority to require HECA to mitigate other operation's emissions. The facility is only required pursuant to Rule 2201 to provide offsets associated with the emissions from the stationary source.

MODELING OF AIR QUALITY HEALTH IMPACTS/AMBIENT MONITORING

Comment 47:
There project will make our already poor air worse and result in adverse health effects.

Response 47:
HECA must meet District requirements concerning control and mitigation of its emissions. The District has some of the most emission control requirements in the nation. The District has analyzed the potential impacts of the HECA proposal on ambient air quality and possible health impacts on the nearby residents and worksites. This process uses very conservative computer modeling techniques approved by the state and federal governments as is explained in the Health Risk Assessment located in Appendix K (Ambient Air Quality and Health Risk Assessment Report) of the Determination of Compliance. Such modeling takes the background emission concentrations, which includes those from the nearby sources, as the baseline concentrations, and it includes the emissions associated with the project.

As is shown in the Ambient Air Quality and Health Risk Assessment Report, such modeling found no expected violations of ambient air quality standards. The District has also performed additional computer modeling to analyze the maximum potential health risk from air toxics generated by the facility. The District's analysis found that air toxics from the HECA facility will not pose a significant risk to the public.

Additionally, Rule 2410 (Prevention of Significant Deterioration (PSD)) requires a PSD evaluation for this facility as a new major source. As is explained in the DOC, this project is subject to the requirements of Rule 2410 for NO2, CO, PM10, and greenhouse gases. Pursuant

to the Ambient Air Quality and Health Risk Assessment Report in Appendix K, compliance with the requirements of Rule 2410 is expected, so the project impacts are not expected to cause the project to violate any of the applicable PSD standards. As presented in the Sections 6 and 7 of that report, the proposed project will not cause or contribute significantly to a violation of the National Ambient Air Quality Standard (NAAQS), and has demonstrated compliance with the other modeling requirement under District Rule 2410.

There are multiple assurances in place to better assure the District and the public that the risks modeled will not be exceeded. There are hundreds of DOC conditions in place to assure and demonstrate compliance, which includes requirements for ongoing monitoring, source testing, maintenance, and recordkeeping.

Comment 48:
In addition to concerns of cancer risk, there were concerns about other health issues (such as asthma or birth defects).

Response 48:
In addition to the estimated cancer risk, the Health Risk Analysis (HRA) in Appendix K also estimates the Acute and Chronic Non-Cancer Hazard Index, which also estimates the acute and chronic health impacts on a maximally exposed individual receptor. These estimates are very conservative and calculate the maximum potential health risk impact. The HRA results indicate that the impacts from the project's emissions on any receptor are below the Significant Threshold of 10 in 1 million for the cancer risk and below 1.0 for the acute and chronic hazard indices.

Comment 49:
Pollution due to the project will damage crops and farmland, as well as hurt wildlife.

Response 49:
The project’s ambient air quality impact analysis and additional analysis including visibility, soils, vegetation, and growth are discussed in the Determination of Compliance evaluation’s Ambient Air Quality Impact and Health Risk Report for District Rule 2201 (New Source Review), District Rule 4201 (Nuisance) and District Rule 2410 (Prevention of Significant Deterioration), which is found in Section 7.1 (Soils and Vegetation) of Appendix K (Ambient Air Quality Impact and Health Risk Assessment Report).

Section 7.1 indicates that the soil and vegetation analysis uses EPA's "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (1980) to determine if maximum modeled ground-level concentrations of NO2, SO2, PM10, H2S and CO from the Project could have an impact on plants, soils, and animals. This analysis indicates that for most types of soils and vegetation, ambient concentrations of criteria pollutants are below the secondary NAAQS and will not result in harmful effects because the secondary NAAQS are set to protect public welfare, including animals, plants, soils, and materials.

Based on the District's consideration of the information and analysis provided by the applicant, and other relevant information, the District does not believe that emissions associated with the

Project will generally result in adverse impacts to soils or vegetation or wildlife, and as a result, no adverse impacts are expected to crops, farmland, and wildlife.

Comment 50:
The Arvin monitor, and not the Shafter monitor, should have been used to establish baseline emission ambient air quality levels for use in the modeling.

Response 50:
The Shafter monitoring site was determined to best represent the ambient NO2 concentration of the HECA facility, whose data was used as the background data for the modeling. At 13 miles away, the Shafter monitoring site is also closer to the HECA facility, compared to a distance of 34 miles for the Arvin monitoring site. The ambient NO2 at the Shafter site is also approximately 56 percent higher than the Arvin site. The ambient ozone is higher in Arvin, approximately 23 percent higher, but the ozone impacts are not modeled. Also, please note that the Arvin monitoring site was shutdown by the California Air Resources Board (CARB), its operator, in late 2010. As a result, this missing NO2 data invalidates the date for the time period between 2008 and 2010. Based on all these facts, it was determined that the Shafter monitoring site is the most appropriate to base the modeling.

Comment 51:
The District should require that HECA install an ambient air quality monitor at the site.

Response 51:
The District has determined that the existing ambient air monitoring network is sufficient to determine ambient air quality levels in the valley, including the areas near the proposed facility. As stated above, the ambient air quality monitor in Shafter has been determined to provide representative air quality information on an ongoing basis for the area near the HECA facility.

Comment 52:
AAQI/Modeling report does not quantify emissions that are modeled.

Response 52:
The emission rates used in the modeling are those quantified in the body of the PDOC. The FDOC includes included revised emission estimates and the modeling has been revised accordingly.

Comment 53:
The NO2/NOx ratio used in the modeling is not consistent with the EPA recommended default values or with the ratio specified in the body of the PDOC.

Response 53:
The 0.2 NO2/NOx ratio used in the modeling was based on District experience and the best information available, and is more appropriate than the suggested default ratio of 0.5. The FDOC has been revised to consistently reflect that a NO2/NOx ratio of 0.2 was used in the modeling.

Comment 54:
One hour peak emissions of NO2 and SO2 emissions were not modeled from all sources.

Response 54:
Modeling was performed for all sources for the applicable ambient air quality standards. For compliance with short term AAQS, the modeling performed for emissions from intermittent sources of emissions is consistent with EPA's 3/1/11 guidance memo concerning modeling requirements for the one hour SO2 and NO2 ambient air quality standards. Due to the very the very low probability that the worst case intermittent short term emissions would occur during worst case meteorological conditions, modeling of intermittent short term emissions is not required to demonstrate compliance with the 1 hour NO2 and SO2 ambient air quality standards.

Comment 55:
Modeling performed for 24 hour impacts of PM10 is based on flawed emission rates and model inputs

Response 55:
All sources of emissions that are permitted and not permitted are included in determining if a facility must comply with attainment NSR (PSD). Once this determination has been made, only sources that will be permitted are evaluated to determine if the project complies with applicable PSD requirements. Therefore, for the purposes of determine if a project complies with PSD requires non-permitted source are not included.

Additionally, non-attainment NSR, District Rule 2201, also only allows for the evaluation of sources that will be permitted. All other emission sources should be included when evaluating the project under the CEQA review process. Since CEC is the lead agency for CEQA they have the responsibility to evaluate the impacts from both permitted and non-permitted sources of emissions when determining compliance with CEQA requirements.

Comment 56:
Staff believes that the background concentrations used should reflect the requirements of the standard and exceptional event data should not be used. CEC recommends the use of background data that excludes exceptional event data that can be obtained from the U.S. EPA AirData website for the NAAQS impact analysis.

Response 56:
The report will be updated with the latest data found on U.S. EPA AirData website. As noted in footnote 5 of Table 6-2, "The value used represents the maximum value including those exceptional events that EPA has not acted on. Therefore this value is only used for modeling only and should not be used to represent compliance with the NAAQS at the monitoring site."

Comment 57:
Staff notes that the following statement on page 32 does not appear to be correct.

"The modeled maximum concentrations of SO2, NO2, PM2.5 and PM10 are also significantly below the secondary NAAQS that have been established by EPA."

Response 57:
Wording on page 32 has been revised clarify the determination made.

Comment 58:
Please ensure that supporting information is available to justify the selected ISRs. Additionally, we recommend forwarding the collected ISR information inclusion in the EPA database.

Response 58:
Data is included in EPA beta database.

Comment 59:
The significant impact area (SIA) is not specifically referenced in the PDOC. Please include a reference in Appendix K that the significant impact area is 13 (thirteen) kilometers.

Response 59:
The SIA has been added to the FDOC.

Comment 60:
Please include, in the engineering evaluation for the permit, a table that presents and summarizes the specific stack parameters (e.g., stack height, temperature, exit velocity, stack diameter) for those equipment and processes in the air quality modeling analyses as described in Appendix K.

Response 60:
Comment noted.

Comment 61:
CEC would like to clarify for the record what we considered in approving HECA's approach for combining monitored and modeled concentrations.

Response 61:
Comment noted.

RULE COMPLIANCE/MONITORING REQUIREMENTS

Comment 62:
PDOC fails to demonstrate compliance with Mercury Air Toxics Rule, 40 CFR 63 Subpart UUUUU.

Response 62:
The FDOC includes a demonstration that the facility is expected to comply with 40 CFR 63 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil Fired Electric Utility Steam Generating Units. Additionally initial compliance testing is required to demonstrate compliance.

Comment 63:
The PDOC fails to address nuisance and potential injury or damage to business or property.

Response 63:
Rule 4102 – Nuisance applies to the proposed HECA facility as well as all other facilities in the District. In implementing Rule 4102, the PDOC included a health risk assessment due for emissions from the facility that are subject to District permit. This health risk assessment demonstrated that the health risk from the facility is below the District's significance threshold of 10 in one million for cancer risk and below 1.0 for the acute and chronic health risks.

The District's authority in evaluating this facility is limited to determining if the facility complies with all District requirements. The District has no authority to regulate or impose conditions for other offsite impacts due to the project. Offsite impacts and other impacts due to the project will be addressed by the California Energy Commission's in their review of the project.

Comment 64:
There was concern about the project's impact on acid rain, and there were questions about the effect of the project's emissions on acid rain in the vicinity of the project.

Response 64:
Acid rain is a regional problem that affects the other regions of the country more than it does in the West. Rule 2540 (Acid Rain Program) is intended to reduce wet deposition (via rain and snow) and dry deposition (by incorporation of SOx and NOx into dust and settling on the ground) of acidic compounds formed in the atmosphere. These requirements apply on a national basis.

To comply with the acid rain program, HECA will have to purchase and retire SOx allowances (different than ERCs) on an annual basis – as implemented by the US EPA. Because HECA is a new coal/coke gasification facility, it must meet NOx and SOx emission requirements, those targeted by the acid rain regulation, that are much lower than a typical coal fired power plant.

Comment 65:
A specific reference method, such as an American Society for Testing and Materials (ASTM) method, should be added to Condition 24 of S-7616-22-0 to define the requirements in "bringing the sample to dryness in a drying oven."

Response 65:
As the gasification solids material handling operations resulted in minimal emissions due to the high moisture content, it was determined that a periodic moisture content test would not be

required, but instead the gasification solids operation will be ensured with visible emissions less than 5% opacity as a means to enforce the low expected emissions from the operation.

Comment 66:
Condition 85 of S-7616-26-0 establishes California Department of Oil, Gas and Geothermal Resources (DOGGR) as the responsible agency for approval of the OEHI CO2 Project Monitoring, Reporting and Verification (MRV) Plan. Currently, the Energy Commission would be the responsible agency for ensuring CO_2 sequestration. The condition should be revised to state: "Except as noted below, the separated pre-combustion CO_2 stream shall be transported to and sequestered by Occidental of Elk Hills (OEHI) in compliance with the latest OEHI CO_2 EOR Project Monitoring, Reporting and Verification (MRV) Plan, or equivalent, that has been approved by the responsible state agency to assure sequestration of the CO_2 transported to and used by the OEHI CO_2 Project."

Response 66:
The District concurs and the conditions have been revised in the FDOC.

Comment 67:
It was recommended that condition 14 of S-7616-40-0, while appropriate for emergency generator engines, does not appear to be appropriate for firewater pump engine. It was recommended to be deleted or revised to describe a fire-based emergency.

Response 67:
This condition has been removed. The unit has sufficient conditions that restrict the operation of the firewater pump engine without the subject condition.

OTHER COMMENTS

Comment 68:
It is recommended that facility-wide conditions be provided separately from the permit-unit specific conditions.

Response 68:
There are certain facility-wide conditions that apply to the facility as a whole, and those are arranged in the same order at either the beginning or the end of each FDOC to assure consistency. Upon conversion of the facility's FDOC into Permits to Operate, a facility-wide permit will be available to place those common conditions that are applicable to all the units.

Comment 69:
The cumulative impacts of the HECA portion of the project along with the CO2 sequestration portion by Occidental of Elk Hills should be considered together.

Response 69:
The cumulative impacts of the HECA facility and CO2 sequestration in the Elk Hills oilfield will be evaluated as part of CEC's evaluation of the project. Such a cumulative impacts analysis is

outside of the scope of the District's authority in evaluating applications that are also subject to approval by the CEC.

Please note that the CEC serves as the sole licensing authority of the proposed project. The District will analyze the impact of Occidental of Elk Hills' operation to sequester the CO2 stream when Occidental submits their application. Any health risk impacts associated with HECA's project will be included in the background emission data for the modeling of the project for sequestering of the CO2.

Comment 70:
The PDOC fails to include an alternatives analysis as required by Rule 2201 section 4.15.1.

Response 70:
The Rule 2201 section 4.15.1 requires that the applicant prepare an alternatives analysis that is equivalent to the requirements of Division 13, Section 2100 et. seq. of the Public Resources Code (CEQA). The PDOC erroneously includes no discussion of the alternatives analysis required in Rule 2201.

The CEC will be preparing an equivalent alternatives analysis as part of its preliminary staff assessment of the project, i.e. prior to the final decision by the CEC on the project.

The FDOC has been revised to indicate that the alternatives analysis cited in Rule 2201 section 4.15.1 will be conducted by the CEC.

Comment 71:
There were comments and suggestions about changing the project or why alternative energy sources were not considered. There were also comments expressing that the proposed project is an experiment with technologies that have not yet been developed.

Response 71:
Please note that the District evaluates the project as proposed and it determines whether the project meets all applicable air quality rules and regulations as proposed. The District cannot change the facility's business plan or scope of the project and cannot judge whether there are better options or if the project does not appear to be the best fit for the Valley.

Comment 72:
Format of the PDOC is formulaic and not adequate to inform the public about the project. Additionally there are several erroneous statements and typographical errors.

Response 72:
The format of the PDOC (and FDOC) is structured in a way that clearly describes our review of the project for compliance with District requirements. Please note that the PDOC does not address compliance with requirements or address concerns that are outside of the District's legal authority. The California Energy Commission's upcoming review of the project will address all applicable requirements for the facility (including non-air related requirements).

Where appropriate, any erroneous statements and typographical errors have been corrected in the FDOC.

Comment 73:
The HECA project is a good project and will be beneficial for Kern County.

Response 73:
Comment noted.

Comment 74:
It appears that the Air Pollution Control District supports the HECA facility. A former District Governing Board member openly endorsed the HECA project while serving on the Governing Board. In particular, the concern was that members of the Governing Board may have influenced the District's decisions of this project.

Response 74:
The District's evaluation of this project is based solely on the project's compliance with the applicable air pollution rules and regulations. There was no influence by any of the Governing Board members over the permitting decisions for this project or any project. The Governing Board is able to comment on and approve rules and matters brought up at the Governing Board meetings, and they set the course of the District. The Governing Board has no involvement in permitting decisions made by the District. Such decisions are made by the APCO and his staff.

Comment 75:
Screening maps established by EPA and possibly other agencies, which show existing concentrations of pollution, should be considered in determining the siting and approval of projects such as these. The commenter felt these maps are to be used to assure environmental justice since they would consider the cumulative impacts from this and other surrounding projects.

Response 75:
The District's sole authority rests in our evaluation of the proposed project complies with air pollution regulations. The siting land use decision regarding the siting of this project rests with the CEC.

Comment 76:
There was concern that the potential emission from the HECA project identified in the Preliminary Determination of Compliance would place the facility among the largest emitters of pollution based on Emission Inventory data. A commenter stated that if the statistics are correct, then this is not a "clean coal" facility.

Response 76:
Comment noted. Please be advised that the emission estimates in the PDOC are potential emissions from the facility, whereas the emission inventory data quoted represents actual

emissions from other facilities. Actual emissions for a facility are routinely less than potential emissions for such a facility, and therefore it is inappropriate to compare potential emissions to actual emissions.

Comment 77:
A carbon sequestration project in South Dakota resulted in CO2 being released in the farmland. The commenter was concerned that this project might have similar results.

Response 77:
Comment noted. The commenter was asked to share this information with the CEC.

Comment 78:
Dispute District's claim that environmental groups promote coal gasification.

Response 78:
Comment noted. However, please note that this facility is cleaner than coal-burning power plants because instead of burning coal, it gasifies the coal, and then burns hydrogen-rich synthesis gas more cleanly. The plant also sequesters a large portion of the generated CO2, a greenhouse gas, which is another benefit over traditional coal-burning projects. Thus, this type of integrated gasification combined cycle technology project is supported over coal-burning projects. In fact, those are some of the reasons the project is supported by and has secured funding from the Department of Energy.

Comment 79:
A commenter asked that the District demonstrate the progress in reducing ozone levels, specifically for the period between 2006 and 2012 because the progress in emission reduction has decreased during those years for ozone. Additionally, due to the slower rate of progress in reducing some pollutants, the commenter questioned the continued use of Emission Reduction Credits (ERCs).

Response 79:
The air quality in the San Joaquin Valley has improved dramatically over what it was 20 years ago. Throughout the state twenty years ago, several air pollutants besides ozone and PM were at harmful levels in California air, including carbon monoxide (CO), sulfur dioxide (SO2), nitrogen dioxide (NO2), and lead. These pollutants no longer exceed health-based standard levels. Also, ozone and PM10 levels used to be much higher than they are currently for most of the State (PM2.5 has been measured for less than 10 years). As is shown in the tables and quality trends for ozone and PM10 by going to the ARB's Trends Summary web pages (which are found at http://www.arb.ca.gov/adam/trends/trends1.php), the trend graphs demonstrate the progress for individual sites or entire regions (as air basins). Ozone and other pollutants continue to decline. Also please see the ozone and PM2.5 trend graphs in the Air District's Report to the Community (2012-13 Edition) (which is available at http://www.valleyair.org/2012-13AnnualReport.pdf) for more information.

As stated previously, District rules provide for the use of ERCs to provide emission offsets.

Comment 80:
How much pollution and greenhouse gases (GHG) would be emitted by the project? What type of controls will be installed, what they will control?

Response 80:
Such information regarding the project's potential emissions for criteria pollutants and GHGs and the types of controls to be installed is included in the FDOC.

Comment 81:
What type of mitigation that would be required for the projects GHG emissions.

Response 81:
The facility will be equipped with BACT for GHG emissions. Additionally, the facility may be subject to CARB requirements for its GHG emissions in the cap and trade program.

Comment 82:
The District should translate the APCO message in the report to the Community into Spanish.

Response 82:
The District provides various outreach material to the public in Spanish. However, the Report to the Community is not yet available in Spanish.

Comment 83:
The facility is the dirtiest plant approved in the District in recent years.

Response 83:
Please note that the facility is equipped with BACT, will provide emission offsets, and will mitigate indirect emissions. The FDOC demonstrates that the facility complies with all District requirements.

Comment 84:
Who will be the responsible agency for ensuring that the transportation of coal will not result in spillage on railroad tracks.

Response 84:
The FDOC includes conditions that require that feedstock materials be removed from the exterior of railcars/trailers after they are unloaded. The CEC may impose other requirements that would be enforced by the CEC.

Comment 85:
There were several comments about to the 400 lb-CO2e/MW-hr emission performance standard listed on the PDOC that is related to the SB-1368 Emission Performance Standard (EPS) requirement.

Response 85:
The 400 lb-CO2e/MW-hr emission performance standard, which was specified in the PDOC, has been removed. This standard was derived from the SB-1368 Emission Performance Standard (EPS) requirements for investor-owned utilities, which is a requirement that would be demonstrated to the California Public Utilities Commission. This requirement was included in the PDOC as an additional metric to demonstrate HECA project's CO2e emission rate compared to the industry standard and other facilities. Since the Air District is not the responsible agency for assuring compliance with SB-1368, and since there currently seems to be some ambiguity as to which portions of the HECA operation need to be included in the EPS calculation, the related discussion was removed. The facility will ultimately need to show compliance with the applicable requirements to the agency that has oversight over this requirement.

Instead, the District will strengthen enforceability of the other GHG BACT requirements to ensure GHG emissions are controlled. Conditions have been added to better verify compliance with the requirements that 90 percent of the pre-combustion carbon in the gasified fuel stream is captured and that the facility demonstrate the facilitywide CO2e limit. Those changes are explained in the responses below.

Comment 86:
There are several deficiencies related to the monitoring of the 90 percent carbon capture efficiency requirements.

Response 86:
The District has added wording to the 90 percent carbon capture requirement specifying that the measurement is based on a 12-month rolling average period.

In regard to the source test method, there are currently carbon capture and sequestration protocols being developed by other agencies that the project will eventually need to meet. Therefore, instead of specifying a method that may conflict with these eventual requirements, a general requirement stating that demonstration with the carbon capture requirement shall be done using an analytical process gas measurement system that complies with a District-approved monitoring plan. The approved monitoring plan will satisfy the testing details (e.g. test method, duration, sample volume, etc.).

Additionally, parametric monitoring of the acid gas removal system will be addressed by adding a condition requiring that the permittee measure the flowrate of the steam treated by the acid gas removal system.

Comment 87:
The facility-wide limit of CO2e was recommended to be demonstrated on a more frequent basis the previous calendar year basis. A demonstration methodology should be added and a rolling 12-month total is recommended.

Response 87:

The CO2e facility-wide limit condition has been redefined as a 12-month rolling limit rather than a calendar year limit.

Additionally, a condition has been added that explain the demonstration methodology for the CO2e facility-wide limit. The vast majority of the CO2e from the project is due to the fuel combustion equipment, the CO2 vent, with smaller percentages emitted from the nitric acid unit, fugitive emissions, and circuit breakers. To address this comment, wording has been added to the conditions requiring compliance with the facility-wide CO2e limit to explain how this limit is to be calculated.

CO2e emissions from entire stationary source (S-7616) shall not exceed 593,965 tons per rolling 12-month period. The permittee shall calculate the CO2e emissions for each calendar month and shall maintain such records onsite for District review. Calculations shall be based on: monthly fuel consumption at the facility and emission factors of fuel (natural gas and diesel CO2e emission factors shall be based on accepted emission factors and syngas CO2e factors shall be based on the amount of carbon in the syngas based on latest monitoring data used to demonstrate carbon removal efficiency); CO2 vent flowrate and the latest monitoring data; nitric acid emission rate (lb-N2O/ton of HNO3 produced) from the latest source test and production; recharge records of circuit breakers; and fugitive emission calculations based on component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components; and urea absorber hours of operation and vendor guarantee of CO2e emission factor. [District Rule 2410]

Comment 88:
EPA is currently proposing to change 100-year global warming potentials (GWPs). To avoid difficulty complying with CO2e limits in the future, when emission limits are expressed in terms of CO2e, the GWPs used should be specified in either the permit or engineering evaluation for the permit.

Response 88:
The emission factors for the CO2e calculations are explained in CO2e calculations section in the evaluation. Those emission factors are based on the currently-accepted 100-year global warming potentials (GWPs).

Comment 89:
The District was urged to present the options to lower the facility-wide CO2e emission limits as its operations moved from early to mature.

Response 89:
The facility-wide CO2e emission limits are based on the maximum potential identified in the project as is the case with evaluation of the other emission rate limits. Evaluation of the project was based on the potential emissions from early operations, which are expected to be higher, with the resultant requirements imposed being based on these higher emissions. Please note that the more restrictive 90 percent carbon capture requirement will also ensure that the CO2e levels controlled through the life of the project.

Comment 90:
There was an inquiry about the level and mode of disclosure and enforceability of the plant's ongoing carbon (CO2e) emissions to ensure that the public can obtain this information and has recourse should the limits be exceeded.

Response 90:
The public can obtain this type of information through a public information requests submitted to the District. The District will be enforcing the emission limits on the DOC, and the permittee will be subject to enforcement action should they violate their conditions.

Comment 91:
Hydrogen Energy California (HECA) provided a long list of comments dated April 30, 2013 regarding the Preliminary Determination of Compliance issued for their project.

Response 91:
The comments provide proposed changes to the evaluation and the DOC conditions due to some project design refinements, clarification of conditions, removal of redundant conditions, proposed procedural changes, and other minor changes like corrections to calculations or typographical errors. As a result, the list of comments is very extensive to respond to each comment individually. Instead a summary of the most significant changes made (and not made) is provided below.

Changes made:

Detailed below are some of the more significant changes to the evaluation and the DOC conditions as a result of HECA's comments. Some of the changes resulted in a change in emissions to the individual units as noted. These individual changes resulted in accompanying changes to the stationary source potential to emit values, the amount emission reduction credit requirements, greenhouse gas totals, BACT discussions, modeling results, etc. The evaluation and DOC conditions have been updated accordingly. Listed below are the more significant changes and a description of the effects of those changes:

- HECA has proposed the addition of a 30,000 cubic foot fluxant storage silo and unloading vent served by a dust collector to the feedstock storage, blending, and reclaim system (S-7616-19-0). The fluxant is necessary to increase the calcium content of the feedstock to achieve vitreous "glass like" gasification solids. The addition of the silo resulted in an increase in PM10 emissions.

- HECA has proposed the addition of a 600,000 gallon methanol storage tank, for the storage of the Rectisol unit solvent, which will be used to supply makeup solvent to the Rectisol unit and to provide adequate storage capacity for the entire solvent inventory when unit maintenance is required. The tank will be served by a methanol scrubber, and will be added to the gasification system (S-7616-21-0) to serve the Rectisol acid gas removal (AGR) unit. The addition of the methanol storage tank has resulted in an increase in VOC emissions.

- The urea HP and LP absorber vents were combined into one urea absorber vent. Since the same combined emissions from the HP and LP absorber vents is now assessed to the one urea absorber vent, there was no change to the emission rates. However, the change in location of at least one of the vents resulted in changes to the modeling.

- New fugitive emission streams have been identified for the project. Those include (18a) CO2 product and purification compressors, (18b) Urea CO2 compressor, (22) Lower benzene concentration, and (23) Higher benzene concentration. As a result, the fugitive emission calculations for units S-7616-21 (gasification system), -23 (sulfur recovery and tail gas compression system), and -33 (ammonia synthesis unit) have also been revised, resulting in slight changes to the potential emissions.

- The maximum design rating of the flare (S-7616-31) serving the sulfur recovery unit has increased, but since the planned flaring rates were not increased, the potential emissions remain unchanged.

- Two new maintenance events were added to the thermal oxidizer serving the sulfur recovery and tail gas compression system (S-7616-23): sulfur recovery unit (SRU) passivation and presulfiding of the tail gas hydrogenation catalyst. As a result there will be in increase in all criteria pollutants.

- Conditions related to the maximum commissioning emissions related to commissioning events have been updated for combustion turbine generator (S-7616-26).

- Conditions related to commission emissions for the nitric acid unit (S-7616-35) have been added.

- CO2 recovery and vent system (S-7616-24) emission concentrations have been revised, resulting in revised calculations.

- The annual dry material process rates for the operations handling dry material were updated. This will not affect the calculated potential emissions, which are based on the maximum design airflow for each dust collectors, the grain loading factor of each dust collectors, and the hours of operation limits. Since the process rate does not affect the calculated emissions, the process rate limits have been removed from the DOC conditions as proposed by the applicant.

- For the engines, there is a requirement that the engines be Interim Tier 4 engines or the highest applicable Tier rating at the time of installation, whichever is higher. The applicant asked for clarification of when Tier rating takes effect. According to the applicable Airborne Toxics Control Measure (ATCM), the engine Tier rating shall be the highest Tier rating in effect on the date of acquisition as defined in 17 CCR 93115.4. Therefore, the conditions related to the latest Tier rating were revised to clarify this issue.

- The flare gas pressure for flare S-7616-30 has now been identified to be less than 5 psig, so the evaluation and DOC conditions were modified to require that flare S-7616-30 be operated in such a manner that it meets the provisions of 40 CFR 60.18 as required by District Rule 4311 (Flares) Section 5.6.

- PM2.5 potential emission values were included in the stationary source potential to emit tables in the evaluation.

- The example composition of gasification solids was updated to reflect the current project design refinements.

- Emission reduction credit (ERC) certificate S-3605-1 has been removed from the list of ERCs to be used to supply the required offsets for this project since there are sufficient credits available with the remaining certificates.

- The annual hours of operation limits on some of the permits were replaced with equivalent throughput or fuel usage rates to facilitate recordkeeping.

Changes not made:

The comments submitted by the applicant included several requests for changes to the DOC conditions that were not made. The most significant items under this category included the following:

- The proposal to add conditions for commissioning events and its emissions for the flare serving the gasification block was not granted. Due to the fact that some of commissioning event emissions from this flare are much greater than the flare's annual Potential to Emit, this was considered a significant change to the project. At this point in the review, such a change would require substantial rework. Therefore, such commissioning activities that result in emissions that are greater than the DOC limits will need to obtain a variance from the District prior to the occurrence of those activities.

- The average period for the nitric acid unit's emission rate limit of 0.20 lb-NOx per ton of nitric acid produced was not changed to a 30-day rolling average as requested in the HECA comments. The District's BACT analysis that developed this limit was based on a 24-hour rolling average

- Testing of total dissolved solids (TDS) for the cooling towers will continue to be required to be done by an independent laboratory, which is consistent with other facilities.

- Specific flare conditions related to compliance with 40 CFR 60.18 (General Control Device and Work Practice Requirements) were kept even if a general requirement that 40 CFR 60.18 be satisfied is already in place.

- Fugitive emission component leaks will continued to be required to be minimized immediately to the extent possible, but no later than 1 hour after detection of a leak, which is consistent with other facilities. Other notification periods were also maintained to retain consistency with other facilities.

- The auxiliary boiler (S-7616-25) will continue to be required to be equipped with a condensate recovery system since it is a GHG BACT requirement.