# Greenhouse Gas Best Available Control Technology (GHG BACT) Analysis for the Hydrogen Energy California (HECA) Project

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**With support from:**
URS

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Region IX

## HYDROGEN ENERGY CALIFORNIA
## Kern County, California

**March 2011**

# GREENHOUSE GAS BEST AVAILABLE CONTROL TECHNOLOGY (GHG BACT) ANALYSIS

*For the*

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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AGR | acid gas recovery |
| BACT | Best Available Control Technology |
| Bhp | brake horsepower |
| Btu | British thermal unit |
| CAISO | California Independent System Operator |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| $CH_4$ | methane |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | carbon dioxide equivalents |
| COS | carbonyl sulfide |
| CTG | combustion turbine generator |
| DOE | Department of Energy |
| EOR | enhanced oil recovery |
| gal/hr | gallons per hour |
| GE | General Electric |
| GHG | greenhouse gas |
| $H_2S$ | hydrogen sulfide |
| HAPS | hazardous air pollutants |
| HECA | Hydrogen Energy California LLC |
| hp | horsepower |
| HRSG | heat recovery steam generator |
| hrs | hours |
| hrs/yr | hours per year |
| Hz | Hertz |
| IGCC | Integrated Gasification Combined-Cycle |
| lb/MWh | pounds per megawatt hour |
| LDAR | leak detection and repair |
| MMBtu/hr | million British thermal units per hour |
| MW | megawatts |
| $N_2O$ | nitrous oxide |
| $NO_X$ | nitrogen oxides |
| $O_2$ | oxygen |
| OEHI | Occidental of Elk Hills, Inc. |
| petcoke | petroleum coke |
| Project | Hydrogen Energy California Project |
| PSD | Prevention of Significant Deterioration |
| psig | pounds per square inch gauge |
| $SF_6$ | sulfur hexafluoride |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| $SO_X$ | sulfur oxides |
| SRU | sulfur recovery unit |
| U.S. EPA | U.S. Environmental Protection Agency |
| VOC | volatile organic compound |

# 1. INTRODUCTION

Hydrogen Energy California LLC (HECA) is proposing to build a first-of-its-kind Integrated Gasification Combined-Cycle (IGCC) power-generating facility called Hydrogen Energy California Project (HECA or Project) in Kern County, California. The Project will produce low-carbon baseload electricity by capturing carbon dioxide ($CO_2$) and transporting it for $CO_2$ enhanced oil recovery (EOR) and sequestration (storage).

The Prevention of Significant Deterioration (PSD) air permit regulations (40 Code of Federal Regulations 52.21 (j)) require new major sources of air pollution to apply Best Available Control Technology (BACT) for each "regulated pollutant" for which the potential to emit is significant. BACT must be applied to new emission units that emit the applicable pollutant. Historically, greenhouse gases (GHGs) have not been considered "regulated pollutants" in the context of PSD and BACT. However, effective January 2, 2011, the U.S. Environmental Protection Agency's (U.S. EPA) Greenhouse Gas Tailoring Rule[1] requires projects that trigger PSD for other pollutants to consider BACT for their GHG emissions in the pre-construction permit review if the project's GHG emissions are above 75,000 tons/year of $CO_2$ equivalents ($CO_2$e). The HECA Project significantly minimizes GHG emissions, through the use of a number of innovative processes to levels substantially below the emissions of other fossil fuel power plants. This GHG BACT analysis has been prepared for the HECA Project PSD permit application to comply with the U.S. EPA's GHG Tailoring Rule and support U.S. EPA's BACT analysis.

The HECA Project will produce low-carbon electricity for delivery to the California Independent System Operator (CAISO) controlled electrical grid. This is accomplished using a dual-fuel–capable combined-cycle power plant that can accept high-hydrogen gas as its primary fuel (sometimes referred to as hydrogen-rich fuel), but alternatively can and will use natural gas as a supplemental or back-up fuel. The power plant produces approximately 400 megawatts (MW) of gross power output, and the combustion of high-hydrogen fuel and/or natural gas are the primary sources of GHG emissions from the Project. The net electrical generation output from the combined facilities (gasification plant and turbine burning high-hydrogen fuel) will provide approximately 250 to 300 net MW of low-carbon baseload power to the CAISO grid, feeding major load sources to the north and south.

The facility also incorporates a hydrogen-fuel production plant that uses a gasification process to transform blends of petroleum coke (petcoke), coal, and steam into high-hydrogen fuel. This process includes all the facilities and energy consumption required to capture and remove $CO_2$ and other constituents from the hydrogen fuel, and deliver the $CO_2$ at sufficient pressure and physical state to Occidental of Elk Hills, Inc., (OEHI) for EOR resulting in sequestration of the $CO_2$ (the "Oxy $CO_2$ EOR Project"). The California Energy Commission (CEC) is conducting the environmental review of the Oxy $CO_2$ EOR Project pursuant to the California Environmental Quality Act, and the CEC, in addition to other relevant agencies, will be reviewing all potential environmental impacts associated with the facilities required for the Oxy $CO_2$ EOR Project.

1 Greenhouse Gas Tailoring Rule – Final Rule, U.S. EPA, Published in the Federal Register (pg. 31514) on June 3, 2010, http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1.

The capture and storage of $CO_2$ results in high-hydrogen fuel production with very low GHG emissions. The HECA Project was designed to have the unique benefit of being located close to a facility that would purchase and use the $CO_2$ for EOR, in addition to providing sequestration. This approach has the effect of improving the economics of producing low-carbon electricity using carbon capture and sequestration.

The combination of the HECA facilities is commonly referred to as an IGCC. The proposed facility's specific IGCC configuration is unique in that, during normal operations, it includes carbon capture and supplies $CO_2$ for use in EOR by a third party (OEHI), and will generate and use a low-carbon high-hydrogen fuel in the combustion turbine. The IGCC is analogous to the combination of a fuel-processing plant, a chemical process unit, and a combined-cycle power plant that converts the fuel to electrical energy. The HECA plant taken as a whole is an innovative integration of existing technologies, creating a first-of-a-kind facility for generating low-carbon electricity.

Overall, the primary source of GHG emissions from the HECA Project is from the combustion of the natural gas at the combined-cycle power plant or remnant GHGs present in the high-hydrogen fuel. The emissions from the combustion of the high-hydrogen fuel come from the remaining 10 percent of the carbon in the fuel, although 90 percent of the carbon emissions will be captured and transported to OEHI for EOR, resulting in sequestration of the $CO_2$. A secondary source of emissions can occur from the hydrogen gas production facility when captured $CO_2$ needs to be vented during breakdowns, malfunctions, failures, and/or upsets of the recovery, compression, or product delivery systems.

A GHG BACT analysis on a power project that incorporates carbon capture and sequestration needs to consider the following two key points:

- GHG limits should recognize and value fuel and energy diversity. Preserving fuel diversity is an important element in electrical system operator forward planning. This Project design and purpose (discussed further in Section 3.1) promotes fuel diversity through the use of solid fuel feedstocks converted to high-hydrogen fuel as the primary fuel, and natural gas as a supplemental fuel when needed, and as a backup fuel.

- GHG emissions should be regulated on a broad timescale, such as annually. GHG impacts are global and observed on a long timescale, such as a decade or century. Regulating annual emissions still achieves the desired GHG reduction at reasonable cost and preserves operational flexibility, which is critical for application of this new technology with highly integrated operations.

# 2. SUMMARY OF FACILITY GHG EMISSIONS AND BACT

## 2.1 OVERVIEW OF EMISSIONS

As described above, the GHG emissions from this Project come predominantly from turbine exhaust, from the combustion of uncaptured carbon, or during venting of $CO_2$ that results from breakdowns, malfunctions, failures, and/or upsets of the recovery, compression, or product delivery systems or during gasifier startups and shutdowns. Emissions from the HECA Project are at their lowest when the entire gasification and hydrogen production facility is operating and the combustion turbine generator (CTG)/heat recovery steam generator (HRSG) are operating on high-hydrogen fuel. However, at times, the facility will have to co-fire natural gas, or operate entirely on natural gas.

There are two BACT determinations that are uniquely important to an IGCC/carbon capture and sequestration project, and that address the majority of potential GHG emissions:

- 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 gases.

HECA submits that GHG BACT is demonstrated by selecting and operating equipment capable of combusting fuels that are inherently low in carbon content. HECA achieves low GHG emissions by using only high-hydrogen fuel or Public Utilities Commission-regulated natural gas to produce electricity. Both of these fuels are recognized as low in carbon content (see Table 5-2). Furthermore, the HECA Project is designed to capture 90 percent of the carbon in synthetic gas (syngas); this 90 percent rate of capture achieved by the HECA Project through its design and engineering of the capture equipment is unprecedented, and significantly exceeds that proposed at other facilities. Section 5 discusses the CTG/HRSG BACT determination.

Plant-wide emissions from different potential operating scenarios are shown in Table 2-1. These scenarios represent the expected range of GHG emissions from the various operating scenarios associated with the Project. During normal steady-state operations (where no breakdowns, malfunctions, failures, and/or upsets happen) the HECA Project is expected to deliver low-carbon power with the $CO_2$ emissions as indicated in Table 2-1. These emissions reflect the performance expected during normal steady-state operations, a few years after startup, when the gasifiers provide a steady high-hydrogen fuel stream for the CTG/HRSG, and all the captured $CO_2$ is sold for EOR, resulting in sequestration. The Natural Gas Emission Scenario shows facility emissions during an annual period of potential CTG/HRSG operation solely on natural gas, even though this scenario is not expected.

**Table 2-1**
**Plant Emissions Under Normal Steady-State and Natural Gas Operating Scenarios**

| Source | Normal Steady-State Operation | Natural Gas Operation |
|---|---|---|
| CTG/HRSG emissions from Natural Gas | 0 | 1,173,900 |
| CTG/HRSG emissions from High-Hydrogen Fuel | 257,881 | 0 |
| $CO_2$ Vent | 0 | 0 |
| All Other Sources[1] | 18,206 | 524 |
| Net Power Generated (MW) [2] | 250 | 310 |
| $CO_2$e Benchmark (lb/MWh) | 265 | 910 |
| **Total Annual $CO_2$e (tonnes/year)** | **276,087** | **1,174,424** |

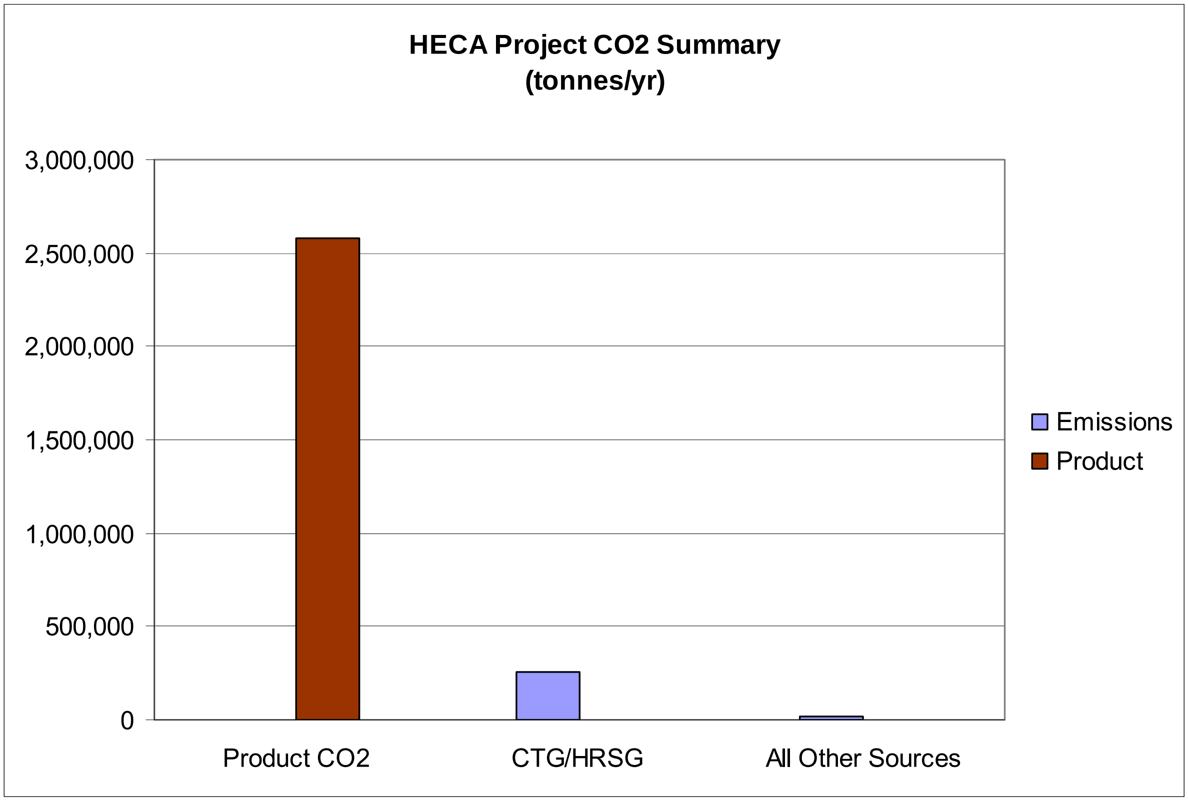
Notes:

1. Includes emissions from other on-site stationary and mobile sources.
2. This is assumed power output. Actual output on high hydrogen fuel could vary from 240 to 300 MW which will have a corresponding impact on emissions and benchmark.

$CO_2$ = carbon dioxide
$CO_2$e = carbon dioxide equivalents
CTG = combustion turbine generator
GHG = greenhouse gas
HRSG = heat recovery steam generator
lb/MWh = pounds per megawatt hour

The above operating scenarios reflect estimates of annual plant emissions of $CO_2$e, with all associated HECA equipment operating at expected rates. The normal steady-state operations case includes 90 percent pre-combustion capture of carbon in the high-hydrogen fuel, which is what enables overall lower GHG emissions from the facility. As discussed further in Section 3, this is part of the plant's overall design and purpose—the capture and sale of $CO_2$ for EOR and sequestration; and the use of hydrogen to fuel the electric generating equipment.

The process by which carbon capture reduces $CO_2$ emissions from the facility is illustrated in the graph below. As shown, the vast majority of $CO_2$ generated from the gasification process during normal steady-state plant operations will be captured, transported to OEHI, and used for EOR, resulting in sequestration of the $CO_2$.




## 2.2 EMISSION UNIT-SPECIFIC BACT SUMMARY

A GHG BACT review was conducted for all proposed emission units. Because the combustion turbine/HRSG and the intermittent $CO_2$ vent account for greater than 90 percent of the emissions from the facility, they have been given the most detailed review in this BACT analysis. However, all GHG emissions sources have been addressed. A summary of the proposed BACT is included in Table 2-2.

Details of these proposed BACT determinations are presented in Sections 5 through 10 of this BACT analysis and summarized in Section 11.

**Table 2-2**
**Summary of Proposed BACT for GHG**

| Source Type | GHG Pollutant | BACT Determination |
|---|---|---|
| Combustion Turbine/HRSG | $CO_2$, $N_2O$, $CH_4$ | Pre-combustion carbon capture (90%) on high-hydrogen fuel<br>Use of natural gas as supplemental/backup fuel |
| AGR & $CO_2$ Recovery System & Vent | $CO_2$ | Good Operating Practices |
| Auxiliary Boiler | $CO_2$, $N_2O$, $CH_4$ | Use of gas fuels, Energy-Efficient Design, Limited Operation |
| Thermal Oxidizer | $CO_2$, $N_2O$, $CH_4$ | Good Operating Practices |
| Gasifier Refractory Heaters | $CO_2$, $N_2O$, $CH_4$ | Good Operating Practices,<br>Use of clean, gaseous fuel |
| Emergency and Startup Flares | $CO_2$, $N_2O$, $CH_4$ | Flare Minimization Plans |
| Equipment Fugitive Leaks | $CO_2$, $CH_4$ | LDAR |
| Emergency Engines | $CO_2$, $N_2O$, $CH_4$ | Good Operating Practices<br>Limited Operation |
| Circuit Breakers | $SF_6$ | Enclosed pressure $SF_6$ circuit breakers with leak detection for equipment failure |

Notes:

AGR = acid gas recovery
BACT = Best Available Control Technology
$CH_4$ = methane
$CO_2$ = carbon dioxide
GHG = greenhouse gas
LDAR = leak detection and repair
$N_2O$ = nitrous oxide
$SF_6$ = sulfur hexafluoride

# 3. PROJECT PURPOSE AND KEY DESIGN FEATURES

Generally, BACT is evaluated for the facility *as proposed* – it does not regulate the purpose or objective for the proposed facility. Put another way, the PSD BACT requirements are not used as a means to 'redefine the design of the source' when considering available control alternatives. Therefore, this section provides a brief summary of the fundamental purpose and design of the proposed HECA Project to provide perspective in determining the range of possible control alternatives considered in this BACT analysis, as well as some key Project design features.

## 3.1 PURPOSE AND DESIGN OF HECA PROJECT

The purpose of this Project is the generation of low-carbon electricity. Additionally, the four key interrelated elements of the proposed Project design and purpose can be summarized as follows:

- Use of low-cost solid fuel (petcoke refining byproduct and/or coal);
- Generation of base-load power production with low GHG emissions;
- Demonstration of the large-scale use of hydrogen for use in very-low-carbon power production; and
- Capture and sequestration of $CO_2$ for reduced GHG emissions in connection with EOR.

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 preferences.

**Feedstocks.** Large amounts of petcoke are produced in California and exported overseas. Petcoke and coal are raw materials that are historically cheaper (per British thermal unit [Btu]) and more widely available in the U.S. than natural gas. The purpose of this Project is to use these readily available traditional solid raw materials/fuels, and demonstrate the generation of clean, low-carbon electricity.

**Hydrogen** is one of the cleanest-burning fuels that can be combusted to generate electricity, especially with regard to GHG emissions. However, hydrogen use for this purpose has not yet been demonstrated in a large-scale application. This Project is revolutionary in the advancement of clean fuel production and electricity generation, as well as reduction of GHGs through low-carbon fuels. The proposed Project will take the revolutionary step of producing clean, gaseous high-hydrogen fuel from some of our most abundant solid fuel resources: petcoke and coal. The production of hydrogen is a key element of the HECA Project.

**EOR**. The Project will demonstrate the capture of more than 90 percent of the carbon from the fuel, prior to combustion in the turbine. The $CO_2$ that is captured from the syngas will be used for enhanced oil recovery in the Elk Hills Oil Field in Kern County, California. This capture step is significant as a demonstration for Department of Energy (DOE) funding under their "Clean Coal Power Initiative," as well as integral to the financial objectives of the Project. The use of EOR to recover local petroleum reserves increases the United States energy independence.

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." [2]

The facility has been designed specifically 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.

## 3.2 KEY PROCESS DESIGN FEATURES

This section discusses some of the overall process design features of the Project that help minimize GHG emissions.

General Electric's (GE) quench gasification technology was identified as the best fit to meet the specific requirements of the proposed Project, and to meet key decision criteria, including the lifecycle cost of electricity and reducing technology risk through demonstrated commercial operation with similar feedstocks (petcoke and coal), at similar capacity and operating conditions. As part of the design evaluation, other gasification technologies were evaluated, including those of Shell and ConocoPhillips, as well as GE's other gasification designs. GE's quench design was selected for the following reasons:

- GE's experience designing solid fuel gasifiers (GE had more than 10 operating facilities at the time of selection.).
- GE gasification has the most IGCC and petrochemical operating hours on U.S. coals and the greatest experience on petcoke and coal/coke blends.
- The GE quench design has been applied widely in syngas generation for chemical production, particularly where sour shift is used to increase syngas hydrogen production and carbon dioxide removal.
- The quench gasification process is well suited for high levels of carbon dioxide capture because of a simple arrangement whereby the steam required by the shift reaction to produce carbon dioxide is generated by water quench of the syngas.

GE's 7F Syngas turbine (formerly called a 7FB turbine by GE) was selected as the combustion turbine for this Project because it is efficient and GE has a large amount of hydrogen firing and development experience. Further information on the efficiency of this turbine relative to other considered turbines is presented in Section 5.1.2.

Another reason that the HECA facility achieves high levels of energy and GHG efficiency is the heat integration incorporated into the process design. Significant heat is generated by the gasification process and several other plant exothermic chemical reactions. This heat is

[2] DOE website: http://www.fossil.energy.gov/recovery/projects/ccpi.html.

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.

# 4. BACT PROCESS OVERVIEW/METHODOLOGY

## 4.1 TOP-DOWN BACT PROCESS

BACT is defined in the Clean Air Act as "*an emissions limit based on the maximum degree of emissions reduction for each pollutant...which the permitting authority determines, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such facility through the application of production processes and available methods, systems, and techniques...*"

The "top-down" BACT process involves the identification of all potentially applicable emission control technologies. Evaluation begins with the top or most stringent emission control alternative. If the most stringent control technology is shown to be technically or economically infeasible, or if the energy, environmental, or other impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated. The top control alternative not eliminated is determined to be the BACT. This process commonly involves the following five steps:

- **Step 1**: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- **Step 2:** Eliminate all technically infeasible control technologies;
- **Step 3:** Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- **Step 4:** Evaluate most effective controls and document results; and
- **Step 5:** Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

BACT is not intended to prohibit increased emissions, but merely to assure that reasonable controls are employed on new or modified sources of large projects.

# 5. COMBUSTION TURBINE/HRSG GHG BACT ANALYSIS

As stated, the HECA Project is designed to generate electricity through the combustion of low-carbon fuel in a gas-fired turbine. After removal of the majority of carbon from the syngas through the acid gas recovery (AGR) system, the Project combustion turbine will fire a high-hydrogen fuel to generate electricity. The turbine can also use natural gas as its primary fuel, or it can co-fire a combination of high-hydrogen fuel and natural gas. For example, natural gas can be co-fired with high-hydrogen fuel if gasifier operations are constrained. Natural gas is the fuel used when starting up the turbine. Natural gas firing also serves as a backup fuel to allow continued electrical power export when high-hydrogen fuel is not available. Excess heat in the turbine exhaust will be recovered as steam and used to generate additional electricity with a steam turbine in combined-cycle mode. Produced power will be exported to the electrical grid and will be used on site to meet the facilities parasitic load. Net electrical generation is between approximately 250 and 300 MW.

## 5.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Three GHG control possibilities have been identified with potential applicability to the proposed combustion turbine:

- Pre-combustion Capture/Low-Carbon Fuels;
- Energy-Efficient Turbine Design; and
- Post-combustion $CO_2$ Capture and Sequestration.

Each of these control options is discussed below.

### 5.1.1 Pre-Combustion Capture/Low-Carbon Fuel

$CO_2$ is a product of combustion generated by any carbon-containing fuel. Virtually all the carbon in a fuel becomes $CO_2$ in the combustion exhaust; therefore, fuels that have lower carbon content, relative to their overall heating value, emit less $CO_2$. During normal operation, the HECA Project generates syngas from coal and petcoke feedstocks, and removes more than 90 percent of the carbon to generate a high-hydrogen fuel, with very low carbon content, which is used in the turbine. The capture rate of 90 percent of the carbon in the total syngas flow is significantly better than has been achieved for similar facilities. The typical composition of this high-hydrogen fuel stream is shown below in Table 5-1.

This high hydrogen content and low carbon content is achieved through the unique process configuration proposed by this first-of-its-kind facility. These low fuel carbon levels represent the practical limitations feasible for use in the proposed turbine and turbine burners.

**Table 5-1**
**High-Hydrogen Fuel Composition (Undiluted)**

| Component | Volume (%) |
|---|---|
| Hydrogen | 89.4 |
| Carbon Monoxide | 1.3 |
| Carbon Dioxide | 5.8 |
| Nitrogen | 2.5 |
| Argon | 1.0 |
| Methane | 0.05 |

This overall process is "pre-combustion" carbon capture. The use of this process allows the combustion turbine GHG emission to be exceptionally low. The Project will capture 90 percent of the carbon in the syngas whenever the gasification system is operating. The captured carbon will be sold for EOR and sequestration, and therefore not emitted into the atmosphere. Due to the close proximity of a buyer for the $CO_2$ product for EOR, pre-combustion carbon capture resulting in sequestration is a feasible option for the HECA Project.

In addition to the normal use of this high-hydrogen fuel, the turbine will also be capable of using or co-firing with ordinary natural gas. The Project needs the flexibility to use natural gas for periods when the gasification system is shut down or upset, and for startups. Natural gas also has a lower carbon content relative to most other fossil fuels. Table 5-2 illustrates $CO_2$ emission factors for a variety of conventional fuels compared to the fuels proposed by this Project.

**Table 5-2**
**$CO_2$ Typical Emission Factors from Stationary Combustion Sources by Fuel**

| Fuel | Pounds $CO_2$ per Million Btu |
|---|---|
| Petroleum Coke[1] | 225 |
| Coal[1] | 210 |
| Distillate Oil[1] | 161 |
| Natural Gas[1] | 116 |
| HECA high-hydrogen fuel[2] | 28 |

Notes:

[1] Source: U.S. Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html.
[2] Source: Project estimates (includes only $CO_2$ in turbine exhaust stream)

Btu = British thermal unit
$CH_4$ = methane
$CO_2$ = carbon dioxide
HECA = Hydrogen Energy California LLC

As the above emission factors illustrate, the Project proposed turbine fuels will have as low or lower $CO_2$ emission rates than 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, high-hydrogen fuel allows these abundantly available solid fuels to be used in an environmentally efficient manner. The flexibility to use natural gas, the lowest-carbon conventional fossil fuel, is important to improve the availability and reliability of this power generation on this first-of-a-kind unit.

The preferential use of low-carbon, high-hydrogen fuel, with 90 percent of carbon removed, and natural gas as a backup/alternative fuel is a highly effective method of reducing $CO_2$ emissions. It is technically feasible and is inherent to the design of the proposed facility.

### 5.1.2 Energy Efficiency (Turbine Design)

Fuel selection is the most important consideration in reducing power plant GHG emissions. Following this, another key component for reducing $CO_2$ emissions is energy efficiency. Because $CO_2$ emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required, and the less 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 electricity, which directly offsets additional firing to obtain the same output.

In this unique project, the GHG emissions from the combustion turbine are not as greatly affected by the turbine system's overall efficiency – due to the use of very low carbon containing fuel. Nevertheless, HECA has proposed an efficient turbine system design.

GE will provide a full commercial offering for the 7F Syngas turbine for this Project that includes operation on both high-hydrogen fuel and natural gas. The GE F-Class turbines have been among the best for economic, efficient, reliable, clean power generation for many years. GE has continued to evolve its "F" technology, with the current 7F being better than its predecessor. Although this will be the first commercial application of this (or any) turbine in high-hydrogen fuel service for electricity generation, the operating experience of the GE F-Class turbines in conventional IGCC syngas service and other power plant operations is also key to its acceptability for this Project.

GE has demonstrated more than 100,000 hours on F-class turbines in syngas service at the SG-Solutions/Public Service Indiana Wabash IGCC and the TECO Polk IGCC power plants. GE originally developed the 7FB combustion turbine for natural gas fired combined-cycle applications. The first commercial unit started operating in 2002. There are now eight operating 7FB (60 Hertz [Hz]) units in the United States, with a total of greater than 20,000 hours of operational history. There also are four operating 9FB (50 Hz) units in Europe with a total of greater than 15,000 hours of operational history.[3]

Siemens and Mitsubishi are also in the development stage for a hydrogen gas turbine, and their offers are expected to be comparably efficient to the GE 7F Syngas high-hydrogen turbine. Next-generation turbine equipment such as H- and J-Class turbines are not available for the Project, because they have not been offered by turbine suppliers for high-hydrogen fuel. HECA is using the most efficient turbine currently offered by vendors for high-hydrogen fuel service, and also the one that has the most experience in IGCC service.

Because the proposed system is designed to optimize IGCC heat integration, operation of the CTG/HRSG in the alternate mode of solely natural gas 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 high-hydrogen fuel.

### 5.1.3 Post-Combustion Carbon Capture & Sequestration

As explained in Section 5.1.1, the Project provides "pre-combustion" carbon capture. As a result, the exhaust stream from the proposed combustion turbine, when firing the high-hydrogen fuel, will have substantially lower $CO_2$ content than standard fossil fuels. This makes "post-combustion" $CO_2$ capture considerably less practical and less achievable. Capture of the $CO_2$ from the turbine exhaust is significantly more difficult than in the pre-combustion synthesis gas stream because of two predominant reasons: Low concentration and low pressure.

Lower concentrations and low pressures mean that there is a very large volume of gas that needs to be treated to recover each pound of $CO_2$. This fact is even more relevant for the proposed HECA turbine when firing its primary fuel—high-hydrogen synthesis gas. Additionally, these same process factors decrease the driving force for the $CO_2$ to be adsorbed into a solvent. Low pressure systems have higher energy demands because solvents designed to absorb significant $CO_2$ at low pressures makes it difficult to get the $CO_2$ to desorb to regenerate and reuse the solvent. Also, a low pressure absorption system would create a low pressure $CO_2$ stream, which would requires even greater energy demand for compression to transport the $CO_2$ for EOR. (Note: The proposed Rectisol system desorbs the $CO_2$ at multiple-staged pressures, minimizing the compression requirements.)

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 combustion turbine exhaust. For the reasons above, the application of post-combustion capture to this particular Project, which already employs 90 percent pre-combustion capture, would be even more impractical.

Although chemical solvent/scrubbing systems have been used commercially at some industrial facilities, the implementation of $CO_2$ 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 this turbine exhaust.

3 Data originally presented in the Revised Application for Certification for Hydrogen Energy California, May 2009.

Developments are generally at an early stage, and the risks to successful commercialization are still high.

The fact that the HECA facility will have a Rectisol AGR system and a commercial outlet for captured $CO_2$ does not sufficiently improve the feasibility of carbon capture and sequestration for post-combustion systems. Rectisol would not be capable of capturing $CO_2$ in the low-pressure turbine exhaust. Rectisol only works in very high-pressure systems where the high partial pressure of the $CO_2$ allows it to be physically captured by the solvent.

Based on the lack of any commercial demonstrations of carbon capture on a turbine exhaust and the very low concentrations of $CO_2$ in the turbine exhaust when firing the primary fuel, post-combustion $CO_2$ capture for the turbine is not a technically feasible option, and therefore is not carried forward in the subsequent steps of this BACT analysis.

## 5.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

The most effective control technologies for reduction of $CO_2$ emissions from the Project combustion turbine include the use of pre-combustion capture, low-carbon fuel. These Project elements are included in the base design of the HECA Project. No other technically feasible technologies are available for this source at this time.

## 5.3 STEP 5 – SELECTION OF GHG BACT FOR COMBUSTION TURBINE/HRSG

The proposed operation with pre-combustion capture/low-carbon fuel represents BACT for the proposed combustion turbine. Project emissions of GHGs are inherently low, due to the fact that the facility is designed to capture more than 90 percent of the fuel carbon prior to combustion in the turbine. Further controls of this source are not warranted or achievable.

GHG BACT for this unit is the use of the most efficient turbine for this dual-fuel service, low-carbon fuels, such as high-hydrogen fuel and natural gas, and the pre-combustion capture of at least 90 percent of the total carbon in the syngas. This will be demonstrated by monitoring the flow rate and carbon content in the captured $CO_2$ stream, and the flow and carbon content of the hydrogen-rich fuel combusted in the CTG/HRSG. The demonstration of pre-combustion capture at a rate of 90 percent will exceed that of any facility currently in operation, and constitutes BACT for this unique and first-of-a-kind facility.

# 6. AGR $CO_2$ VENT BACT ANALYSIS

In addition to removing sulfur from the syngas, the plant's AGR system will capture more than 90 percent of the carbon in the raw syngas during steady-state operation and separate it into a high-purity $CO_2$ product stream. This $CO_2$ stream is an important product of the facility. During normal operations, it will be compressed and transported by pipeline to the customer, OEHI, who will use it for EOR in the nearby existing Elk Hills oil field, resulting in sequestration. The HECA Project site was selected, in part, due to its close proximity to the Elk Hills Oil Field. 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 $CO_2$ 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 custody transfer point for use by OEHI. However, it is not possible to guarantee 100 percent availability of the pipeline and EOR systems. The $CO_2$ stream will need to be vented during breakdowns, malfunctions, failures, and/or upsets, such as outages of the $CO_2$ compressor or pipeline; or when the $CO_2$ off-taker is unable to accept the $CO_2$ stream, and during gasifier startup and shutdowns. The flow rate during these periods of venting will be measured, and will be included in the HECA overall recordkeeping requirement under the Project's applicable CEC and San Joaquin Valley Air Pollution Control District (SJVAPCD) permits. In addition, venting duration is indirectly limited by separate emissions limits on carbon monoxide (CO), volatile organic compound (VOC), and carbonyl sulfide emissions in the SJVAPCD permit.

The $CO_2$ stream will be transported and sold (approximately 2,500,000 tonnes/yr of $CO_2$) to OEHI. The sale of this stream for EOR and sequestration serves the dual beneficial purposes of providing for long-term geological storage of the $CO_2$, while also increasing the oil production from these existing oil wells, thus enhancing domestic oil supplies.

This section of the BACT analysis discusses potential controls for the $CO_2$ vent stream during the intermittent periods when the $CO_2$ product stream cannot be delivered to OEHI.

## 6.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

The vent stack will allow for infrequent venting of produced $CO_2$ when the $CO_2$ EOR injection system is unavailable or unable to export due to breakdowns, malfunctions, failures, and/or upsets conditions; or during gasifier shutdown and subsequent gasifier restart. The $CO_2$ vent exhaust stream will be nearly all $CO_2$, with only trace (parts per million) levels of some criteria pollutants.

Possible controls identified for this source include:

- Minimize Venting – Good operating practices of the compression and transportation system; and
- Alternative storage for captured $CO_2$.

Each of these methods and the feasibility for this Project are discussed below.

### 6.1.1 Minimization of Venting

GHG emissions from this source are proposed to be controlled by limiting venting to periods when the compression and transportation system are unavailable, and during gasifier startup and shutdown. The use of good operating practices will minimize interruptions to the compression and transportation systems.

### 6.1.2 Alternative Storage

For periods when the pipeline cannot receive the $CO_2$ stream, there are no other realistic alternative $CO_2$ storage opportunities. Building tanks for short-term storage of this product is not practical or safe. Even compressed to 200 pounds per square inch gauge (psig) (the pressure of a standard propane tankcar), the plant's daily production of $CO_2$ would require storage space equivalent to more than 2,000 pressurized railcars (assuming 30,000 gallons each). The only reasonable storage option for large volumes of $CO_2$ is underground geological structures (such as the proposed EOR sales outlet).

## 6.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

As discussed above, the only feasible GHG control alternative for this emissions source is good operating practices of the HECA $CO_2$ compression and transportation systems. Therefore, this is proposed as the top control technology. There are no negative impacts of this option.

## 6.3 STEP 5 – SELECTION OF GHG BACT FOR $CO_2$ VENT

As the only technologically feasible option, BACT for GHG emissions from the $CO_2$ vent is proposed to be good operating practices of the HECA $CO_2$ compression and operating systems**.** Because this is an important power sales attribute and $CO_2$ product revenue source, there is an inherent and strong financial incentive for HECA to perform at a high level of reliability. The SJVAPCD permit already restricts venting of this stream only to periods when the compression and transportation system is unavailable due to breakdowns, malfunctions, failures, and/or upsets; or during a gasification block startup or shutdown.

# 7. AUXILIARY BOILER GHG BACT ANALYSIS

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. During normal operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no sparging), and will not have emissions. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 142 million British thermal units per hour (MMBtu/hour) (high heating value), but will have a much lower average firing rate. The significant heat efficiency and process integration steps discussed in Section 3.2 allow for the auxiliary boiler to be in standby mode during normal steady-state full plant operation. Average annual firing, allowing for startups, shutdowns, and partial load situations, will be no more than 35.5 MMBtu/hr.

## 7.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Potentially applicable GHG control technologies considered for the auxiliary boiler include:

- Post-combustion $CO_2$ capture and sequestration;
- Energy-efficient overall facility design – allowing limited boiler firing;
- Use of lower-carbon fuels;
- Energy-Efficient Boiler Design (air preheater, economizer, condensate recovery, etc.);
- Periodic burner tuning (to maintain efficiency); and
- Limited operation.

### 7.1.1 Post-Combustion $CO_2$ Capture and Sequestration

As discussed under the analysis for the combustion turbine, post-combustion $CO_2$ capture is a relatively new concept, and rarely used on combustion systems. Unlike the gasification AGR system, which generates a concentrated $CO_2$ stream ideal for capture, capture of the $CO_2$ from the boiler exhaust is significantly more difficult because the $CO_2$ is at a low concentration and low pressure. Also, since the average firing rate of this boiler is no more than 35.5 MMBtu/hr, there is very little $CO_2$ to be captured.

Based on the lack of commercial demonstrations and the excessive costs, the implementation of $CO_2$ capture systems for small- to medium-sized combustion systems is not a realistic BACT consideration. This is further supported by the recently issued U.S. EPA GHG BACT guidance document[4], which recommends that Carbon Capture and Sequestration only needs to be considered in a BACT analysis for very large $CO_2$ sources and industrial facilities with high-purity $CO_2$ streams (cement production, iron and steel, etc.). For example, in Appendix F, the U.S. EPA presents an example BACT for a 250 MMBtu/hr natural gas fired boiler. In this

[4] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, U.S. EPA Office of Air and Radiation, pp. 34, 35.

example, carbon capture is not even listed in step one (1) of the BACT analysis as a potentially available options[5]. The HECA Project auxiliary boiler will have a maximum heat rate of 142 MMBtu/hr, which is even smaller than this U.S. EPA example, and will average only 35.5 MMBtu/hr.

Therefore, we do not consider post-combustion $CO_2$ capture for the small, limited-use auxiliary boiler to be a technically feasible option, and do not carry it forward in the subsequent steps of this BACT analysis.

### 7.1.2 Energy-Efficient Facility Design

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. These are the most significant measures, resulting in the low GHG emissions from this source. Due to these plant design features, the auxiliary boiler will operate in "standby" service most of the time. The SJVAPCD permit restricts the use of this emissions source by limiting its allowable annual average fuel firing rate to the 311 billion Btu/year (~35.5 MMBtu/hr 12-month average), which is consistent with the Project emissions calculations.

### 7.1.3 Lower-Carbon Fuel

Carbon dioxide 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 $CO_2$ emissions versus use of solid fuels. The HECA Project auxiliary boiler will fire natural gas as a lower-carbon fuel, despite the fact that coal and/or pet coke is available on the site. The Project considered the use of the product high-hydrogen fuel, but this is not feasible because it will not be available during most periods when this boiler is being used (startups, shutdowns, upsets). Also, because reliability of this boiler is important for emergency situations, the use of more reliable natural gas is preferred, even when the high-hydrogen fuel is available.

### 7.1.4 Boiler Energy Efficiency

Another opportunity for reducing GHG emissions is to maximize the energy efficiency of the boiler. Because $CO_2$ emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the boiler, the less fuel that is required, and the fewer GHG emissions that result.

Although the use of this boiler results in only minimal fuel consumption and GHG emissions, three energy efficiency measures have been identified that may be applied to this combustion source:

***Heat Recovery with an Economizer:*** to recover additional heat from the boiler exhaust to preheat boiler feed water. This reduces the heat energy required from fuel combustion to heat

[5] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, U.S. EPA Office of Air and Radiation, p. F-1.

the boiler water. (Note: for some types of boilers, an alternative exhaust heat recovery step could be using the hot exhaust in an air preheater, instead of an economizer. However, air preheaters are very unusual for natural gas boilers, and are no more effective in recovering exhaust heat than a boiler feed water economizer. Additionally, preheating the air could slightly increase nitrogen oxides emissions. Consequently, use of an economizer has been considered, rather than an air preheater.)

***Condensate Recovery*** by returning the hot steam condensate from the process as feedwater, thereby decreasing the boiler heat load.

***Inlet air trim controls*** can limit excess air by using a stack CO or oxygen ($O_2$) monitor and automatically adjusting inlet air. Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process.

The auxiliary boiler is proposed to include Heat Recovery Economizer and Condensate Recovery, but not Inlet Air Controls. Optimizing excess air can be a cost-effective measure on large boilers, but is uncommon for small boilers, or boilers with limited use. According to the U.S. EPA's Boiler White Paper, manufacturers estimate that a 1 percent thermal efficiency can be achieved with oxygen trim control.[6] The SJVAPCD permit restricts the firing of this auxiliary boiler to no more than 142 MMBtu/hr and 311 billion Btu per year, which is equivalent to an annual average firing rate of 35.5 MMBtu/hr. At this rate, an improvement of 1 percent thermal efficiency (resulting in 1 percent lower firing) would reduce annual GHG emissions only about 165 tons per year. Due to the small size of 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.

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 (on an average load basis) and its infrequent operation does not justify the incremental costs for this measure. (Note: this is consistent with the example presented in Appendix F of U.S. EPA's November 2010 GHG BACT Guidance[7], in which blowdown heat recovery was not cost effective for a 250 MMBtu/hr natural gas boiler.)

### 7.1.5 Periodic Boiler Tuning

A combustion system can drift over time from its optimum setting. HECA proposes to tune the combustion system every 2 years by conducting a visual check by an experienced boiler engineer to ensure that everything is in working condition and set per manufacturers' recommendations, or optimum settings developed for the particular boiler.

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[6] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, U.S. EPA, October 2010, p. 14.

[7] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, U.S. EPA Office of Air and Radiation, p. F-2.

## 7.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for the limited-use auxiliary boiler, the remaining control options are:

- Use of Natural Gas;
- Energy-efficiency measures (Economizer and condensate recovery); and
- Periodic tuning.

## 7.3 STEP 5 – SELECTION OF GHG BACT FOR AUXILIARY BOILER SOURCES

BACT is proposed to be use of natural gas as a fuel; design with economizer and condensate recovery as energy efficiency measures; and periodic tuning. Further, the existing SJVAPCD permit restricts the GHG emissions from this source by limiting its allowable annual average fuel firing rate to 311 billion Btu per year.

# 8. TAIL GAS THERMAL OXIDIZER AND GASIFIER PREHEAT BURNER GHG BACT ANALYSIS

In addition to the primary combustion in the turbine, there are a few other miscellaneous combustion sources that are part of the HECA Project. These include the Thermal Oxidizer, and gasifier preheat burners, which are described below.

**Tail Gas Thermal Oxidizer:** 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 hydrogen sulfide ($H_2S$) (after scrubbing) and other vent gases that are generated during startup, shutdown, and times of non-delivery of carbon dioxide 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 normal operation to prevent nuisance odors. The thermal oxidizer operates at high temperature and provides sufficient residence time in order to ensure essentially complete conversion of reduced sulfur compounds like $H_2S$ to sulfur dioxide. The thermal oxidizer fires natural gas (10 MMBtu/hr) continually to maintain the required operating temperature for proper thermal destruction.

**Gasifier Refractory Pre-heat Burners:** Each of the three gasification trains will have one natural gas fired burner used to warm the gasifier refractory to facilitate startup or for hot standby. These burners will not operate when the gasification train is operating. The gasifier warming burners operate at 18 MMBtu/hr, firing natural gas for a combined total of 3,600 hours of normal operation per year for all three heaters.

Each of these sources and their respective fuels, firing rate, and resulting GHG emissions are listed in Table 8-1.

**Table 8-1**
**Miscellaneous Combustion Sources**

| Source | Fuel | Operating Rate | $CO_2e$ (tonnes/year) | Percent of Facility Total $CO_2e$ |
|---|---|---|---|---|
| Thermal Oxidizer | Natural Gas, SRU Process Stream | 10 MMBtu/hr (8,760 hrs/yr) | 4,480 | <1% |
| Gasifier Warming | Natural Gas | 18 MMBtu/hr (3,600 hrs/yr) | 3,431 | <1% |

Notes:

$CO_2e$ = carbon dioxide equivalents
hrs/yr = hours per year
MMBtu/hr = million British thermal units per hour
SRU = sulfur recovery unit

As can be seen from the table above, each of these sources is relatively small, and/or operates only for a fraction of the year. They represent less than 1 percent of the total $CO_2$e that will be emitted from the facility. The following sections briefly analyze potential GHG controls for these specific sources.

## 8.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Potentially applicable GHG control technologies considered for the tail gas thermal oxidizer and gasifier refractory pre-heater burners include:

- Use of lower-carbon fuel;
- Energy-Efficient Design;
- Post-combustion $CO_2$ Capture and Storage; and
- Limited operating hours (for preheat burners).

### 8.1.1 Lower-Carbon Fuel

All of the miscellaneous combustion sources will fire natural gas as a lower-carbon fuel. The high-hydrogen fuel that is generated at the facility and used in the combustion turbine is not available during startups, and is not a suitable failsafe fuel source for the gasifier preheater or thermal oxidizers.

### 8.1.2 Energy Efficiency

The gasifier refractory preheat burners are very small and intermittent sources. They have no air inlet controls or heat recovery because they are simple, small burners, and therefore are not technically or economically feasible for those sources. Likewise, the thermal oxidizer is too small of a source to justify monitoring excess $O_2$, controlling air rate, or trying to recover waste heat.

No applicable energy efficiency measures are identified to carry forth in the BACT analysis.

### 8.1.3 Carbon Capture & Sequestration

Post-combustion $CO_2$ capture is not technically feasible for these small sources for the same reason it is not feasible for the combustion turbine and auxiliary boiler. These sources are even smaller than the combustion turbine and auxiliary boiler and it would be even more difficult, expensive, and uncertain to try and implement in these services.

## 8.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for miscellaneous combustion sources, the remaining technologies are:

- Use of natural gas fuel; and
- Limited operating hours (for preheat burners).

## 8.3 STEP 5 – SELECTION OF GHG BACT FOR MISCELLANEOUS COMBUSTION SOURCES

BACT for these miscellaneous combustions sources is the use of natural gas fuel, and limiting the hours of operation of the preheat burners. These limits are already in place in the SJVAPCD permit.

# 9. FLARES GHG BACT ANALYSIS

Although the Project is designed to avoid flaring during steady-state operations, flares are needed for safe operations and to protect the operators and equipment. The Project employs three pressure-relief systems and their corresponding flares (Gasification, Rectisol, and sulfur recovery unit [SRU]) for this purpose. All three flares are conventional pipe, elevated flares. 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, CTG offline washes, or emergency upset events. During normal, non-startup plant operation, the three flares will be operated in a standby mode with only *de minimis* emissions from the natural gas pilot flames. The flares will be used to occasionally dispose of excess startup gases in a safe manner. Any time the flares are used, GHG emissions will be generated, although the total annual emissions are expected to be less than 4 percent of the facility total.

## 9.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Potentially applicable GHG control technologies considered for the flares include:

- Minimization of amount and duration of flaring; and
- Flare gas recovery systems.

### 9.1.1 Minimization of Flaring

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 VOC and hazardous air pollutant (HAP) constituents. Any time these gases are combusted in the flares, emissions of $CO_2$ and nitrous oxide ($N_2O$) are generated. Flare minimization is equally important to minimizing criteria pollutants, and has been incorporated into the base facility design and the SJVAPCD permit. The following permit conditions in the SJVAPCD permit serve to minimize flare-generated GHG emissions:

- Requirement for Flare Minimization Plans;
- Gasification Flare planned use limited to 40,680 MMBtu per day of any gas, 91,500 MMBtu per year of unshifted gas, and 105,400 MMBtu per year of shifted gas;
- SRU Flare planned use limited to 36 MMBtu/hr of natural gas assist and 40 hours per year of planned flaring;
- Rectisol Flare planned use limited to 8 hours per day and 40 hours per year of planned flaring; and
- Non-resettable total flow meters for each flare to monitor flaring.

### 9.1.2 Flare Gas Recovery

HECA has also considered whether the use of a flare gas recovery compressor could be appropriate. Flare gas recovery has been implemented at some facilities that produce and use internally-generated fuel gas streams such as petroleum refineries. However, 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 occurs during an entire plant shutdown where no gases are being produced. Flaring at the proposed HECA facility, will be an infrequent occurrence during breakdowns, malfunctions, failures, and/or upsets. Planned flaring occurs during gasifier startup and shutdown, which is estimated to occur approximately 40 hours per year, and during offline CTG washes, which happen no more than 12 times per year.

Another significant difference is that refineries can recover some flare gas into their fuel gas cleanup system which operates 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 to allow it to be routed 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 flared gases.

Given the extremely infrequent nature of flared gases being 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.

## 9.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for flares, the remaining option for GHG control is minimization of amount and duration of flaring.

## 9.3 STEP 5 – SELECTION OF GHG BACT FOR FLARES

BACT for GHG emissions from the HECA flares is minimization of the amount and duration of flaring. This will be accomplished through Flare Minimization Plans, as well as the permit conditions in the existing SJVAPCD permit, which serve to minimize the amount of material flared. As a secondary effect, these conditions serve to limit GHG emissions as well other criteria pollutant emissions.

# 10. MISCELLANEOUS SOURCES GHG BACT ANALYSIS

The analyses for other small sources of GHG emissions—such as emergency engines, fugitive emissions from equipment leaks, and circuit breakers—are included in this section.

## 10.1 EMERGENCY ENGINES

The HECA Project has three emergency engines: two diesel-fired 2,922 horsepower (hp) standby generators, and one diesel-fired 556 hp standby fire-water pump, as shown in Table 10-1.

**Table 10-1**
**Emergency Equipment Combustion Sources**

| Emergency Engines | Bhp | Max. Fuel, gal/hr |
|---|---|---|
| Emergency Generator, Unit 1 (2 MW) | 2,922 | 140 |
| Emergency Generator, Unit 2 (2 MW) | 2,922 | 140 |
| Emergency Fire Water Pump Engine | 556 | 28 |

Notes:

* All engines will meet California interim Tier 4 standards for 2011 model year (2013 delivery.)

Bhp = brake horsepower
gal/hr – gallons per hour
MW = megawatt

These emergency diesel engines will have the potential to emit GHGs ($CO_2$, methane [$CH_4$], and $N_2O$) because they will combust hydrocarbon fuel. However, because their use is limited to routine maintenance, inspection, and testing, their total emissions are very small. The use of diesel fuel is standard for emergency engines because it is the most reliable fuel for emergency scenarios. The use of electric engines or 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 fire-pump engine is to limit its use, and to use an efficient engine. HECA proposes to do both.

HECA will use new engines meeting the latest efficiency and pollutant performance standards. Specifically, regarding criteria pollutants, these standby diesel-fired engines will meet the California Interim Tier 4 standards for 2011 models (with 2013 delivery expected).

The standby fire-water pump engine use will be limited to no more than 100 hours per year for reliability testing and maintenance purposes. The stand-by electric generators will each be limited to no more than 50 hours per year of operation. HECA proposes a BACT permit reflecting this limited use, which is consistent with the existing limit in the SJVAPCD permit.

## 10.2 FUGITIVES ($CO_2$ AND $CH_4$)

The Project estimates there will be approximately 39 tons of $CO_2$e per year of emissions from HECA equipment and pipe component leaks, such as pumps, valves, flanges and compressors, after implementation of the leak detection and repair (LDAR) program. This includes both $CO_2$ and $CH_4$, and will be less than 0.01 percent of total facility emissions.

The SJVAPCD permit requires HECA to implement a Leak Inspection and Maintenance program for control of HAPs and VOCs on fugitive components in the gasification and sulfur recovery unit process areas. These areas include some streams that contain $CO_2$ and $CH_4$. The use of leak detection and repair, though not specific for GHG emissions, has the secondary benefit of reducing GHG from these process units.

Because total fugitive emissions of $CO_2$e from equipment components are so small, relative to the overall facility emissions, further control of fugitive emissions would have minimal additional benefit. The Project proposes the LDAR program as outlined in the SJVAPCD permit as BACT for fugitive emissions of GHG.

## 10.3 CIRCUIT BREAKERS (SULFUR HEXAFLUORIDE)

The facility's circuit breakers will also have the potential to emit a very small amount of GHG, sulfur hexafluoride ($SF_6$). Circuit breakers do not emit $SF_6$ directly, but they do have the potential for fugitive emissions (leaks). The HECA Project site will include a switchyard with approximately 8 circuit breakers, with a total $SF_6$ inventory of approximately 1,600 pounds (1 tonne) of $SF_6$ in the enclosed-pressure breakers. $SF_6$ is a gaseous dielectric used in the breakers. It is a potent GHG with a "global warming potential" over a 100-year period 23,900 times greater than $CO_2$. Leakage is expected to be minimal. Even assuming a 0.5 percent annual leak rate, HECA estimates emissions equivalent to only 86 tonnes per year $CO_2$e. Nevertheless, this small source has been considered for purposes of this GHG BACT analysis.

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The proposed alternative is to use state-of-the-art $SF_6$ technology with leak detection to limit fugitive emissions. In comparison to older $SF_6$ circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for $SF_6$ 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. 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 $SF_6$ (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the $SF_6$ has escaped, so that it can be addressed proactively in order to prevent further release of the gas and maintain the insulation value in the circuit breakers. The use of enclosed-pressure $SF_6$ circuit breakers with leak detection is feasible for this location. HECA has proposed to use this equipment because of its performance benefits.

Another alternative is to substitute another, non-GHG substance for $SF_6$ as the dielectric material in the breakers. One alternative to $SF_6$ would be 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 $SF_6$ breakers. This type of technology is feasible, although $SF_6$ has become the predominant insulator and arc-quenching substance in circuit breakers today because of its superior capabilities. Additionally, this type of circuit breaker would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the $SF_6$ breakers. The larger oil/air-blast breakers would require additional land to 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 $SF_6$ breakers because of their negative qualities and the fact that the use of the latest $SF_6$ breakers only results in very small GHG emissions. This is further supported by the most recent report released by the EPA $SF_6$ Partnership, which states: "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[8] Research and development efforts have focused on finding substitutes for $SF_6$ that have comparable insulating and arc quenching properties in high-voltage applications.[9] Although some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an $SF_6$ substitute"[10] for high-voltage applications.

Based on this analysis, HECA concludes that using state-of-the-art enclosed pressure $SF_6$ circuit breakers with leak detection would be the BACT option.

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[8] SF6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, December 2008, p. 1 (available at www.epa.gov/electricpower-sf6).

[9] See, e.g., Christophorou, L.G., J.K. Olthoff and D.S. Green, 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 (hereinafter, "NIST Technical Note 142"); available at: http://www.epa.gov/electricpower-sf6/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," at 185; available at: http://www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf.

[10] 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); available at: http://www.sea.siemens.com/SpeedFax06/Speedfax06files/06Speedfaxpdfs/06Speedfax_13/13_28-29.pdf..

# 11. BACT DETERMINATION SUMMARY

Table 11-1 summarizes the BACT proposed as a result of this GHG BACT analysis. The table also notes key relevant permit conditions from the existing SJVAPCD permit that also serve to restrict facility operation and limit GHG emissions.

**Table 11-1**
**Summary of Proposed BACT Permit Limits for GHG**

| Source Type | BACT Determination | Proposed GHG-Specific BACT Limit | Relevant SJVAPCD Permit Limits for Criteria Pollutants |
|---|---|---|---|
| Combustion Turbine/ HRSG | High-hydrogen fuel Firing: Pre-combustion capture of $CO_2$<br>Natural Gas Firing: No further controls. | Capture 90 percent of carbon prior to combustion of high-hydrogen fuel (as monitored through $CO_2$ in fuel < 10 percent of total fuel and captured $CO_2$ stream) | Fire only natural gas or high-hydrogen fuel<br>Hourly, daily, and annual limits on $NO_X$, VOC, CO, $PM_{10}$, $SO_X$<br>Monitor fuel consumption |
| $CO_2$ Recovery System and Vent | Compression and Transport $CO_2$ to EOR<br>Good Operating Practices | No additional limits required beyond existing air permit | Venting only when compression or pipeline is unavailable and during gasifier startup and shutdown<br>Flow measurement<br>Concentration, hourly, and annual limits on CO, VOC, and COS |
| Auxiliary Boiler | Use of gas fuels, Energy-Efficient Design, process heat integration | Boiler tuning and limits from existing air permit | Fire only natural gas;<br>Total annual heat input limited to 311 billion Btu and monitor fuel use |
| Thermal Oxidizer | Good Operating Practices | No additional limits required beyond existing air permit | SRU limited to 210 long tons per day |
| Gasifier Refractory Heaters | Good Operating Practices | No additional limits required beyond existing air permit | Fire only natural gas; Operation limited to 3,600 hrs/yr combined |
| Emergency and Startup Flares | Good Operating Practices<br>Flare Minimization Plans | No additional limits required beyond existing air permit | Flare Minimization Plans, Total flow monitors |

**Table 11-1**
**Summary of Proposed BACT Permit Limits for GHG (Continued)**

| Source Type | BACT Determination | Proposed GHG-Specific BACT Limit | Relevant SJVAPCD Permit Limits for Criteria Pollutants |
|---|---|---|---|
| Equipment Fugitive Leaks | No further controls | No additional limits required beyond existing air permit | LDAR on select process areas |
| Emergency Engines | Good Operating Practices | No additional limits required beyond existing air permit | 50 hrs non-emergency operation per year for electric generators;<br>100 hrs/yr for firewater pump |
| Circuit Breakers | Enclosed pressure $SF_6$ circuit breakers with leak detection | Use of enclosed pressure $SF_6$ circuit breakers with leak detection | No SJVAPCD Permit Limits |

Notes:

BACT = Best Available Control Technology
Btu = British thermal unit
CO = carbon monoxide
$CO_2$ = carbon dioxide
COS = carbonyl sulfide
CTG = combustion turbine generator
GHG = greenhouse gas
HRSG = heat recovery steam generator
hrs = hours
hrs/yr = hours per year
LDAR = leak detection and repair
$NO_X$ = nitrogen oxides
$PM_{10}$ particulate matter less than or equal to 10 microns in diameter
$SF_6$ = sulfur hexafluoride
SJVAPCD = San Joaquin Valley Air Pollution Control District
$SO_X$ = sulfur oxides
SRU = sulfur recovery unit
VOC = volatile organic compound

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**APPLICATION FOR CERTIFICATION FOR THE *HYDROGEN ENERGY CALIFORNIA, LLC PROJECT***

**Docket No. 08-AFC-8**

**PROOF OF SERVICE**
**(Revised 3/1/11)**

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## DECLARATION OF SERVICE

I, Dale Shileikis , declare that on March 7 , 2011, I served and filed copies of the attached Greenhouse Gas Best Available Control Technology (GHG BACT) Analysis , dated March , 2011. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/hydrogen_energy]**.

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

### (*Check all that Apply*)

**FOR SERVICE TO ALL OTHER PARTIES:**

X sent electronically to all email addresses on the Proof of Service list;

____ by personal delivery;

X By delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses **NOT** marked "email preferred."

***AND***

**FOR FILING WITH THE ENERGY COMMISSION:**

X sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

***OR***

____ depositing in the mail an original and 12 paper copies, as follows:

**CALIFORNIA ENERGY COMMISSION**
Attn: Docket No. 08-AFC-8
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Dale Shileikis