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Dockets Unit
California Energy Commission
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Sacramento, CA 95814-5512

Re: Watson Cogeneration Steam and Electric Reliability Project
Application for Certification 09-AFC-1

On behalf of Watson Cogeneration Company, the applicant for the above-referenced Watson Cogeneration Steam and Electric Reliability Project, we are pleased to submit the following:

- Greenhouse Gas BACT Analysis in support of the PSD Permit Application.

This document was filed with EPA Region IX on December 30, 2011.

This document is being submitted to the CEC for docketing.

In accordance with the CEC's June 10, 2011 Committee Order Adopting Filing and Electronic Documents Directives, one paper copy and one compact disc (CD) is being filed with the Dockets Unit. The Proof of Service distribution will receive CDs. Paper copies will be issued upon request.

Sincerely,
URS Corporation

CH Fischer

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Enclosure

cc: Proof of Service List

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Watson Cogeneration Steam and Electric Reliability Project
Greenhouse Gas BACT Analysis

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Prepared for Submittal to
Environmental Protection Agency
Region IX
San Francisco, CA

December 2011

BACT Analysis for Greenhouse Gas Emissions for the Watson Cogeneration Steam and Electric Reliability Project-Unit #5.

1.0 Introduction

The Watson Cogeneration Steam and Electric Reliability Project (Project) is a proposed expansion of a steam and electrical generating (cogeneration) facility that is located in the City of Carson in Southern California. The Project will complete the original design of Watson Cogeneration Facility that has been in continuous operation for more than 20 years. The Project will add a nominal 85 megawatt (MW) combustion turbine generator (CTG) with a single-pressure heat recovery steam generator (HRSG) to provide additional process steam to the BP Carson Refinery. The Project will increase the overall reliability of the steam delivered from the existing Watson Cogeneration Facility. The original facility design allocated plot space and included provisions to accommodate an additional CTG/HRSG train at a later date. The additional train is sized and designed to operate in parallel to the four existing CTG/HRSG trains under base load conditions and includes supplemental duct firing in the HRSG. In addition, the Unit #5 project systems (turbine and HRSG) are designed to be consistent with the existing turbines and HRSGs with respect to fuels fired, i.e., natural gas and refinery gas. The ability to fire refinery gas in the existing and the newly proposed Unit #5 is essential to the refinery in that without this capability, the refinery gas, would by necessity need to be combusted in less efficient devices such as boilers, process heaters, or flares. Therefore, the use of refinery gas is an important and integral part of the project design.

The Project includes one General Electric (GE) 7EA CTG with an inlet fogging system, one duct fired HRSG, two redundant natural gas compressors (2x100 percent), one boiler feedwater (BFW) pump, one circulating water pump, two new cells added to an existing cooling tower, an electrical distribution system, instrumentation and controls, and all necessary auxiliary equipment as described herein. The GE 7EA CTG and associated HRSG are sturdy, proven industrial workhorses ideal for meeting the refinery steam supply requirements. The steam produced by the fifth train will be delivered to the existing steam header system shared by the four existing cogeneration trains.

The Project complements the existing cogeneration facility located within the confines of the refinery. The existing facility has four GE 7EA CTGs, four HRSGs and two steam turbine generators (STG). In operation since 1988, the existing cogeneration facility is owned by Watson Cogeneration Company (Watson) and operated by BP West Coast Products, LLC – BP Carson Refinery. Watson is a joint partnership between subsidiaries of BP America and Edison Mission Energy. Since the Project consists of adding a fifth CTG/HRSG to the existing configuration, it is also referred to as the “fifth train or Unit #5.”

Unit #5 will operate in parallel with Watson’s existing four cogeneration units. The Project will improve the overall efficiency of Watson as well as improve the reliability of steam deliveries to the refinery.

The Watson Cogeneration Facility and the Project are sized to thermally match the steam needs of the refinery. In addition to meeting the refinery’s need for steam, a portion of the electrical power generated by Watson is sold to the refinery and the remaining excess power is exported to the electric grid. The high reliability of the Watson Cogeneration Facility also significantly reduces the possibility of refinery upsets due to loss of power. Excess electricity generated by the

Project will require Watson to enter into a power sales contract to enable additional power to be exported to the electric grid.

1.1 Basis for GHG BACT

In November of 2010, EPA issued guidance to assist permit writers and permit applicants in addressing the prevention of significant deterioration (PSD) and Title V permitting requirements for greenhouse gases (GHGs) that began to apply on January 2, 2011. The guidance document: (1) describes, in general terms and through examples, the requirements of the PSD and Title V permit regulations; (2) reiterates and emphasizes relevant past EPA guidance on the PSD and Title V review processes for other regulated air pollutants; and (3) provides additional recommendations and suggested methods for meeting the permitting requirements for GHGs, which are illustrated in many cases by examples. EPA issued this guidance in response to inquiries from permitting authorities and other stakeholders regarding how these permitting programs would apply to GHG emissions. The guidance was finalized in March of 2011.

New major stationary sources and major modifications at existing major stationary sources are required by the Clean Air Act (CAA or Act) to, among other things, obtain an air pollution permit before commencing construction. This permitting process for major stationary sources is called new source review (NSR) and is required whether the major source or major modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where the NAAQS have not been exceeded (attainment and unclassifiable areas). In general, permits for sources in attainment or unclassifiable areas are referred to as prevention of significant deterioration (PSD) permits, while permits for major sources emitting nonattainment pollutants in major amounts and located in nonattainment areas are referred to as nonattainment NSR (NNSR) permits. The entire preconstruction permitting program, including both the PSD and NNSR permitting programs, is referred to as the NSR program. Because EPA has not established a NAAQS for GHGs, the nonattainment component of the NSR program does not apply. Thus, the NSR portions of the EPA guidance focus on the PSD requirements that apply once GHGs become a regulated NSR pollutant.

For stationary sources, on March 29, 2010, EPA made a final decision to continue applying (with one refinement) the Agency's existing interpretation regarding when a pollutant becomes "subject to regulation" under the Act, and thus covered under the PSD and Title V permitting programs applicable to such sources. EPA published notice of this decision on April 2, 2010. Under EPA's final interpretation, a pollutant becomes "subject to regulation" on the date that a requirement in the CAA or a rule adopted by EPA under the Act to actually control emissions of that pollutant "takes effect" or becomes applicable to the regulated activity (rather than upon promulgation or the legal effective date of the rule containing such a requirement). Thus, under EPA's interpretation of the Act and applicable rules, construction permits issued under the PSD program on or after January 2, 2011, must contain conditions addressing GHG emissions.

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of the PSD and Title V programs to enable EPA and states to phase in permitting requirements for GHGs in a common sense manner ("Tailoring Rule"). The Tailoring Rule focuses on first applying the CAA permitting requirements for GHG emissions to the largest sources with the most CAA permitting experience. Under the Tailoring Rule, facilities responsible for nearly 70 percent of the national GHG emissions from stationary sources are subject to permitting requirements beginning in 2011, including the nation's largest GHG emitters. i.e., power plants, refineries, and cement production facilities. Emissions from small farms, churches, restaurants, and small commercial facilities are examples of source types that are not likely to be covered by these programs under the Tailoring

Rule. The rule then expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

The first Tailoring Rule step began on January 2, 2011, and ended on June 30, 2011, and this step covered what EPA has called "anyway sources" and "anyway modifications" that would be subject to PSD "anyway" based on emissions of pollutants other than GHGs. The second step began on July 1, 2011, and continues to cover both anyway sources and certain other large emitters of GHGs. EPA has committed to completing another rulemaking no later than July 1, 2012, to solicit comments on whether to take a third step of the implementation process to apply the PSD permitting programs to additional sources. EPA has also committed to undertaking another rulemaking after 2012. Sources subject to the permitting programs under the first two steps will remain subject to these programs through any future steps. Future steps are not discussed in the March 2011 guidance document, given that the outcomes of those rulemaking efforts are not yet known. Under the Tailoring Rule, in no event are sources with a potential to emit (PTE) less than 50,000 TPY of CO2 equivalent (CO2e) subject to PSD or Title V permitting for GHG emissions before 2016. (*PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011*.)

1.2 Project Description

The Watson Cogeneration Company will construct and operate one new General Electric (GE) 7EA combustion turbine generator (CTG) with one duct fired heat recovery steam generator (HRSG) and two additional cells added to the existing cooling tower. The Project's primary objective is to provide additional process steam in response to the process steam demand at the BP Carson Refinery. The original design of the Watson facility allocated plot space for a new unit at a later date and included provisions to accommodate it. The additional unit is sized and designed to provide reliable base load operations with supplemental duct firing in the HRSG.

The Project will operate as a base loaded cogeneration unit and is proposed to be permitted for 8,760 hours of operation per year. The expansion project will consist of the following:

- Installation of a nominal 85 megawatt (MW) GE 7EA Dry Low NO_x (DLN) combustion turbine with inlet fogging.
- Installation of the HRSG producing up to approximately (~) 659 Klbs steam/hr and equipped with a duct burner with up to 448 MMBtu/hr (high heating value [HHV]) heat input.
- Installation of two additional cells to the existing seven cell wet cooling tower to provide cooling and heat rejection from the new power block process.
- Installation of all required auxiliary support systems.

The Project design will incorporate the air pollution emission controls designed to meet SCAQMD BACT determinations. These controls will include DLN combustors in the CTG to limit nitrogen oxide (NO_x) production, Selective Catalytic Reduction (SCR) with anhydrous ammonia for additional NO_x reduction in the HRSG, an oxidation catalyst to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions. Fuels to be used will be pipeline specification natural gas, refinery gas, or a mix of pipeline specification natural gas and refinery gas**.** Low NO_x burners will be incorporated into the HRSG.

Specifically, the project will have the following characteristics.

Combustion Turbine

- Manufacturer: GE
- Model: 7EA
- Fuel: Primary-natural gas; Secondary-natural gas/refinery gas blend
- Heat Input: 1062.1 mmbtu/hr (HHV)
- Fuel consumption: up to ~1,030,238 standard cubic feet per hour
- Exhaust flow: ~872,656 actual cubic feet per minute at ISO Conditions
- Exhaust temperature: ~385 degrees Fahrenheit (°F) at the HRSG stack top exit

Heat Recovery Steam Generator

- Manufacturer: Not Selected
- Model: N/A
- Fuel: Primary-refinery gas; Secondary-natural gas
- Duct Burner Heat Input : up to 448 mmbtu/hr (HHV)
- Steam Production Rating: 659 Klbs/hr (maximum)
- Duct Burner Manufacturer: John Zink or equivalent

Cooling Tower Cells (additional cells on existing seven-cell tower)

- Manufacturer: Marley or equivalent
- Number of Cells: 2
- Number of Fans: 2 (~945,000 actual cubic feet per minute each)
- Water circulation rate: 9,300 gallons per minute per cell
- Drift rate: 0.001 percent (0.00001 fraction)
- Expected TDS: ~3,575 parts per million by weight (ppmw)

The fuel used on this project is similar to the fuels used on the existing cogeneration facility. Specifically, the fuel in the CTG will initially be based on firing pipeline quality natural gas or a blend of pipeline quality natural gas and low sulfur refinery gas. It is anticipated that the blending of refinery gas in the CTG will not exceed 35 by weight percent of the total mixed flow into the CTG, due to hydrogen limitations in the fuel requirements as specified by GE. The HRSG will be fueled with either 100 percent natural gas or 100 percent refinery gas. There are no proposed fuel mixture limitations on the HRSG. For the emission calculations presented in the CEC Application for Certification (AFC), the HRSG emissions were based upon a worst-case assumption of 100 percent refinery gas in order to maximize the total emissions while the combustion turbine emissions were based on the 35 by weight percent blend of refinery gas in the total mixed gas stream. The natural gas will meet the Public Utility Commission (PUC) grade specifications. The refinery gas sulfur will be limited to meet the SCAQMD BACT limits.

Currently, the SCAQMD air basin is attainment/unclassified for nitrogen dioxide (NO_2), sulfur dioxide (SO_2), TSP, and CO, and is non-attainment for PM10, PM2.5, and ozone. Based on the values presented below Combustion Turbine/HRSG Emissions for the Project (Including Base Load, Cold and Warm Startup and Shutdown, Whichever is Greater), and Cooling Tower Emissions for the Project (2 Cells), the new facility will be a major modification to an existing major stationary source per SCAQMD NSR Regulation XIII for all criteria pollutants. Detailed emissions data on the facility are presented in Application for Certification filed with the California Energy Commission. Based upon the annual emissions, the facility will not trigger the Prevention of Significant Deterioration (PSD) program requirements for any attainment pollutant with the exception of CO_{2e}. Therefore a PSD analysis for CO_{2e} is presented in the following sections. Table 1 presents a summary of emissions for the proposed expansion project.

Table 1 Summary of Facility Emissions for the Project

Pollutant	lbs/hr	lbs/day	tons/year
NO_x	11.94	637.40	39.9
CO	14.54	863.02	64.8
VOCs	4.16	99.84	18.2
SO_x	6.84	164.16	29.95
TSP	5.0[1]	120.0[1]	21.9[1]
PM10/2.5	10.0[1]	240.0[1]	43.8[1]
CO_{2e}	---	---	See Appendix A

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide
CO_{2e} = carbon dioxide equivalents (see Appendix A)
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
SO_x = sulfur oxide
TSP = total suspended particulate
VOCs = volatile organic compounds
Including startup and shutdown emissions, and cooling tower PM_{10}.
[*] TSP filterable portion as referenced in appendix S of 40 CFR part 51.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day.

Figure 1 and Figure 2 show the project location and project layout respectively. Figure 3 shows the process flow diagram for the project.

Figure 1
Project Location Map

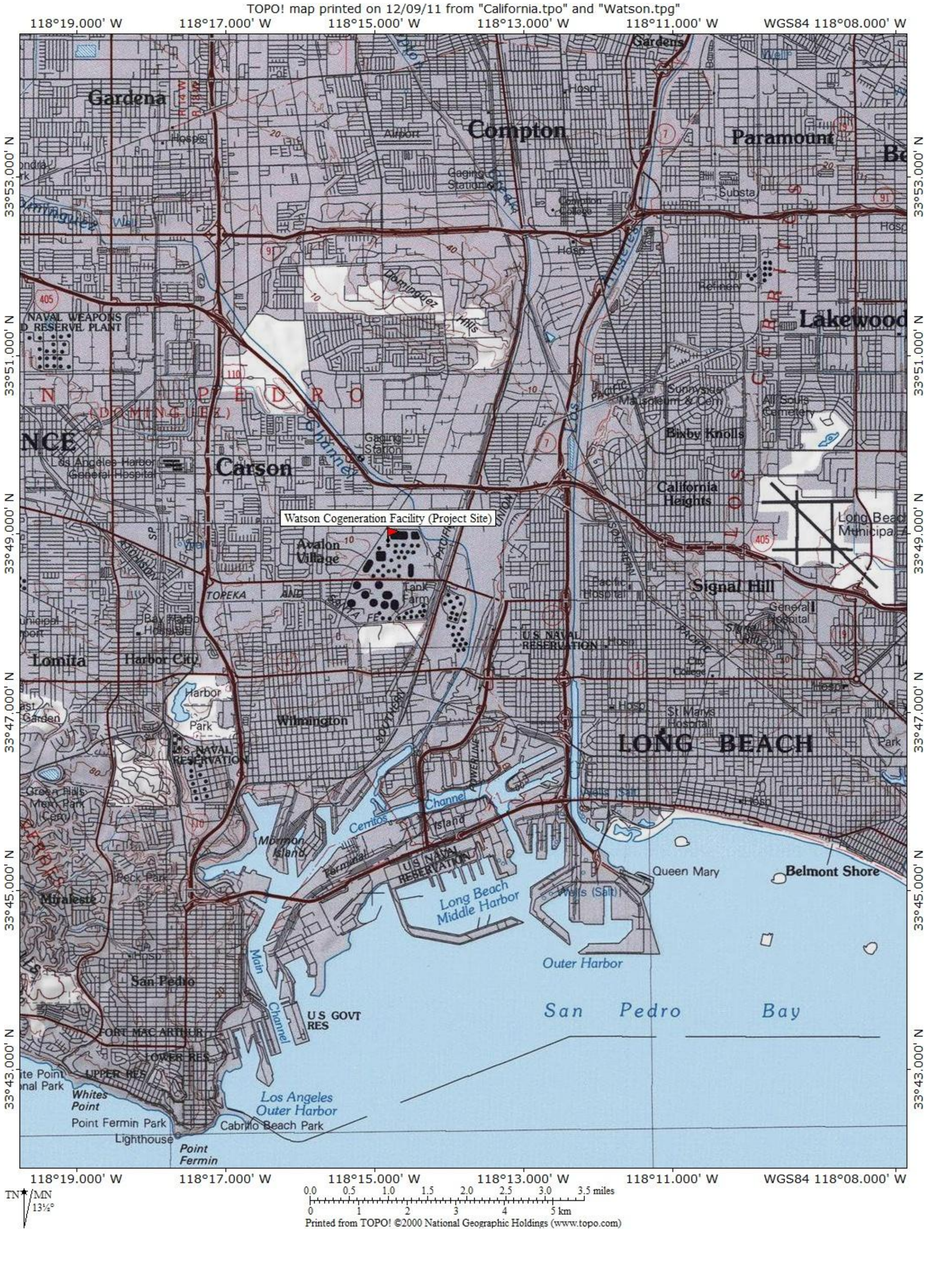


Figure 2
Project Onsite Layout

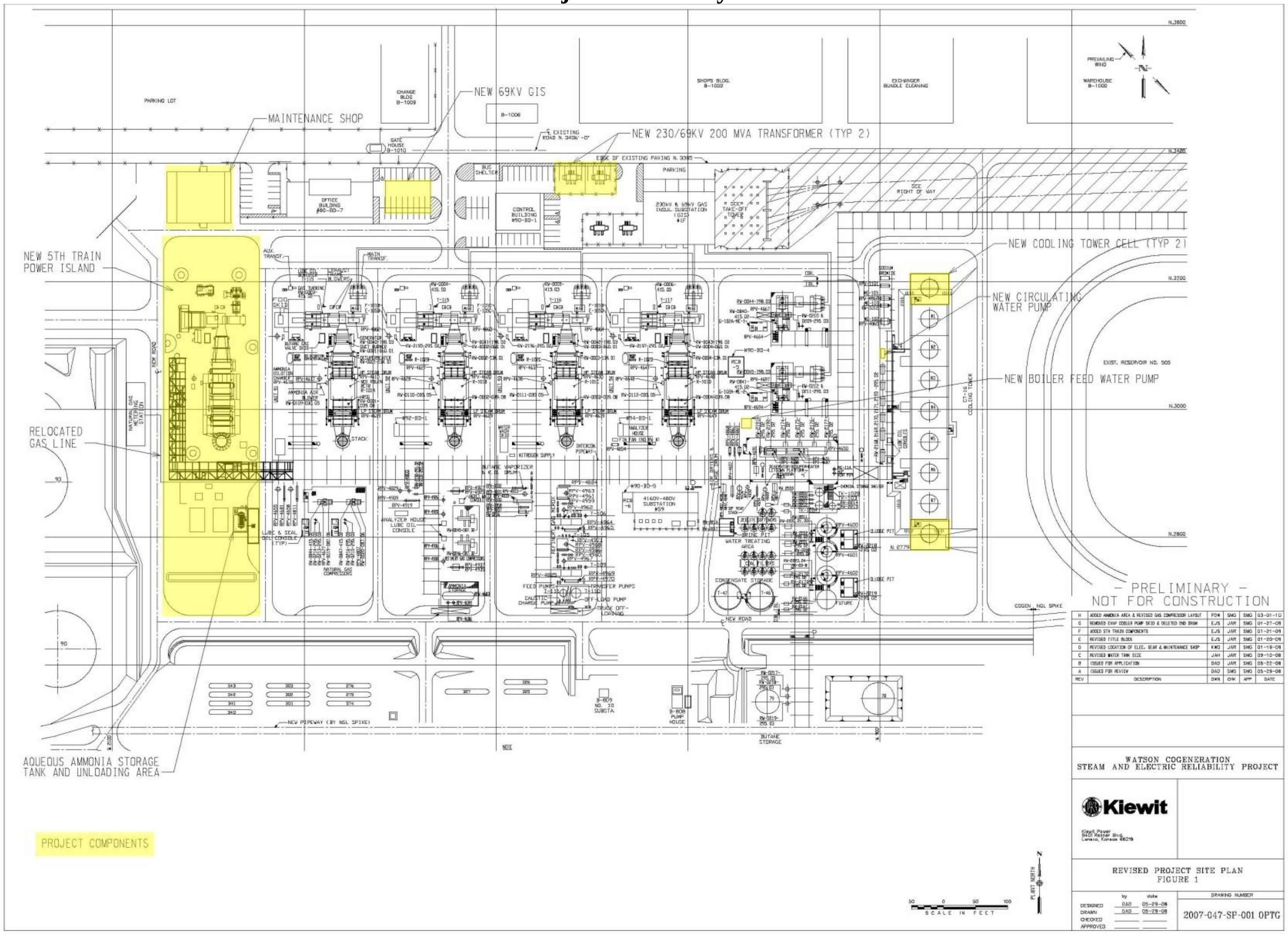
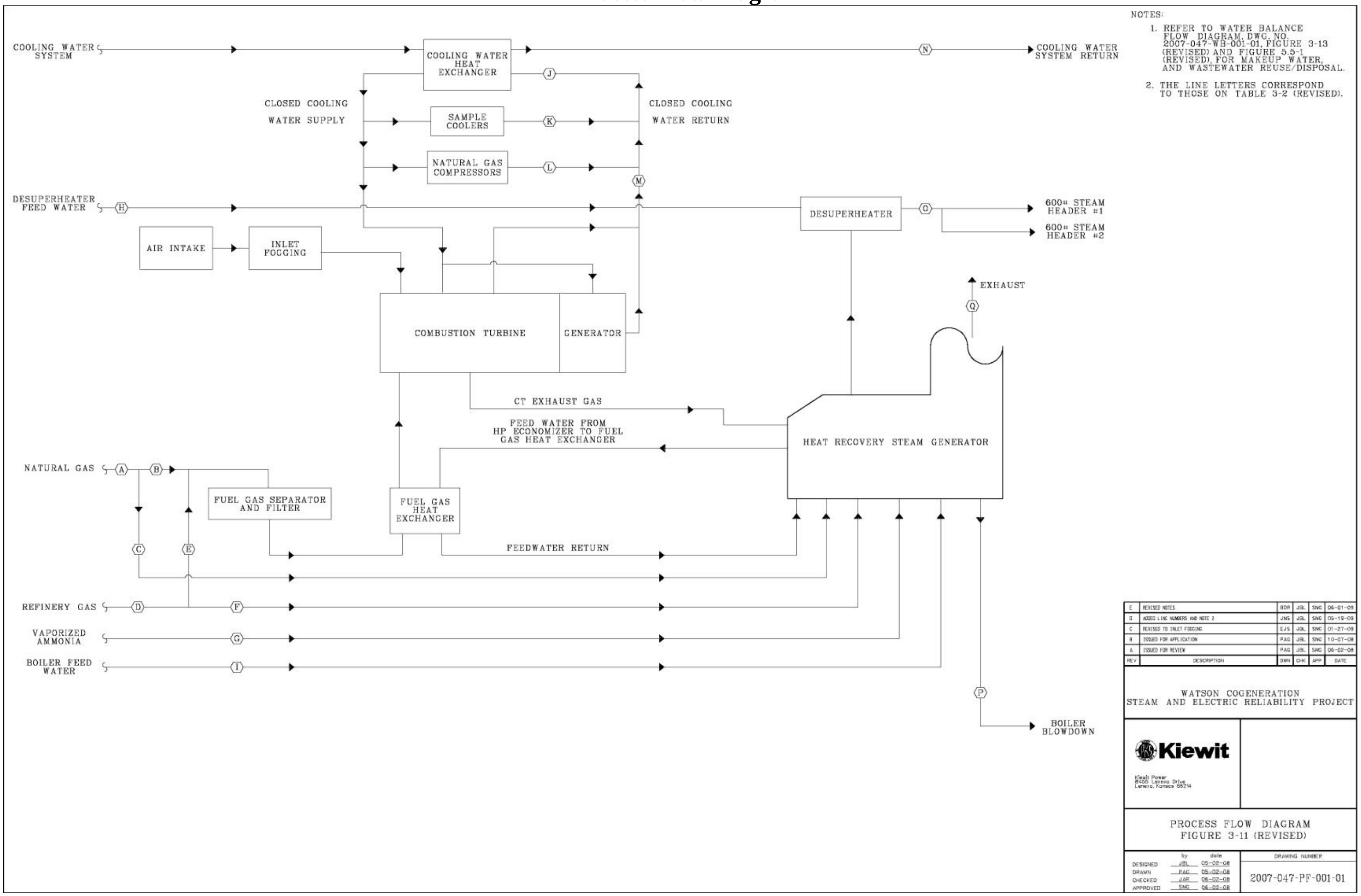


Figure 3
Process Flow Diagram



2.0 Part A - CEC AFC FSA Greenhouse Gas Evaluation (excerpts only, with the applicant's corrections noted in brackets) *Reference: CEC Final Staff Assessment, CEC 700-2011-002-FSA, August 2011, Docket 09-AFC-1*

2.1 CEC Assessment

The Watson Cogeneration Steam and Electric Reliability Project (BP Watson [Watson Project]) is a proposed addition to the state's electricity system that would produce greenhouse gas (GHG) emissions. And, more importantly, BP Watson [the Watson Project] would cogenerate steam to improve the operations at an existing petroleum oil refinery and burn waste refinery gas while generating electricity. The proposed BP Watson project [Watson Project] will add a nominal 85 megawatt (MW) combustion turbine generator (CTG) with a single-pressure heat recovery steam generator (HRSG) to provide additional process steam to the BP Carson refinery.

The additional unit is sized and designed to provide reliable base load operations with supplemental duct firing in the HRSG. The project includes one General Electric (GE) 7EA CTG, with an inlet fogging system, one duct fired HRSG, two redundant natural gas compressors, one boiler feed-water (BFW) pump, one circulating water pump, two new cells added to an existing cooling tower, electrical distribution system, instrumentation and controls, and all necessary auxiliary equipment as described herein.

BP Watson's objectives are to cogenerate additional process steam in response to the refinery's process steam demand, burn waste refinery gases, and generate electricity. Electricity is produced by operation of an inter-connected system of generation resources. Operation of one power plant, like the BP Watson project [Watson Project], affects all other power plants in the interconnected system. But, the operation of the BP Watson cogeneration project [Watson Project] would also affect (i.e., displace) the use of an industrial steam boiler too. The operation of BP Watson [Watson Project] would affect both the overall electricity system operation, industrial steam boiler operation, and, therefore, GHG emissions in several ways:

- The BP Watson project [Watson Project] would contribute to the Air Resources Board's goal of adding new combined heat and power (CHP or cogeneration) resources by 2020 as part of their strategy to meet the greenhouse gas emissions reduction goals of AB 32. CHP, by "using" fuel energy twice to generate both electric power and process heat, dramatically increases the net efficiency of the fuel use and reduces California GHG emissions.

- The BP Watson project [Watson Project] would provide replacement energy for high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's new Emissions Performance Standard implemented as required by SB 1368.

- The BP Watson project [Watson Project] would replace generation capacity provided by aging and once-through cooling power plants in the Los Angeles Basin Local Capacity Area. It is presently anticipated that replacement capacity will be needed for a share of the once-through cooling capacity in the area.

- The BP Watson project [Watson Project] would help to meet local and system-wide resource adequacy (RA) requirements. The project's net qualifying capacity (NQC) will be determined by its exports to the grid during peak hours in each month. Average onsite

> electricity consumption during the peak hour of the year reduces forecasted demand by a similar amount (plus avoided transmission and distribution losses), and thus reduces system-wide and local capacity requirements through its impact on the demand forecast.

As proposed, BP Watson [Watson Project] would be used in a base load mode of operation to provide for process steam to an adjacent thermal host – BP Carson Refinery. The high reliability of the BP Watson [Watson Project] facility would significantly reduce the possibility of refinery upsets due to loss of steam or power. With an expected capacity factor of up to 95 percent, BP Watson [the Watson Project] would continue the trend of newer, more efficient natural gas facilities displacing electrical energy production from older, less efficient facilities. However, BP Watson [Watson Project] will not be able to run at this very high utilization rate unless it is either providing on-site power or it can arrange contract terms to accommodate such a high usage rate. BP Watson has not provided any information to demonstrate that such a high utilization rate is likely, but for purposes of GHG calculations and estimates, BP Watson used 100 percent capacity factor, or 8,760 hour of operation per year.

The project would meet the Greenhouse Gases Emission Performance Standard (EFS; Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants. Any utility that enters into a contract with the BP Watson project [Watson Project] would need to seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed PPA, and any other conditions that dictate the operation of the BP Watson project [Watson Project]. The BP Watson [Watson Project] cogeneration facility as proposed meets the EPS of 0.500 metric tons (1,100 lbs) CO2 per megawatt-hour, with a rating of approximately 0.318 metric tons CO2 per megawatt-hour. Because the cogeneration unit can operate over a range of ambient conditions, burning a mixture of natural gas and waste refinery gas, and generating a range of steam delivery rates, the amount of fuel chargeable to the electricity generation can vary.

Staff notes that mandatory reporting of the GHG emissions provides the necessary information for the California Air Resources Board to develop greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project is subject to reporting requirements and will be subject to GHG reductions or trading requirements as part of California's GHG cap-and trade program as these regulations are more fully developed. On a federal level, 40 CFR 98 requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO2 equivalent emissions per year.

California is actively pursuing policies to reduce GHG emissions, and combined heat and power projects like the BP Watson [Watson Project] cogeneration project that improve energy use efficiency will contribute to these policies. Additionally, California continues to add modern power plants to generate electricity more efficiently, thereby reducing GHG emissions. Lastly, California is adding non-GHG emitting renewable generation resources to the system mix.

In this context, and because fossil-fueled resources produce GHG emissions, it is important to consider the role and necessity of also adding fossil-fuel resources such as the BP Watson project [Watson Project]. On October 8, 2008, the Energy Commission adopted an order initiating an informational (OII) proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA). A report prepared as a response to the GHG OII defines five roles that gas-fired power plants are likely to fulfill in a high-renewables, low-GHG system:

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

The Energy Commission staff-sponsored report reasonably assumes that nonrenewable power plants added to the system would almost exclusively be natural gas-fueled, given that gas generally is dispatchable, can meet local and federal air pollutant standards, and is relatively low-GHG emitting. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable and can be more difficult to permit. Solid fueled projects are also generally base load, not dispatchable, and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed. Further, California has almost no sites available to add highly dispatchable hydroelectric generation.

This analysis provides the staff's conclusions concerning greenhouse gas emissions for this siting case. Future power plant siting and amendment cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission. This analysis recognizes that the "prudent use" of natural gas for electricity generation will serve to optimize the system (CHP, integrating intermittent renewable generation and providing reliability), but, without further analysis and policy direction by the Commission to refine this general understanding, this analysis leaves the implications for optimizing the system to future cases.

The Energy Commission established a precedent decision in the Final Commission Decision for the Avenal Energy Project. This precedent decision requires all new natural gas fired power plants certified by the Energy Commission to: (a) not increase the overall system heat rate for natural gas plants, (b) not interfere with generation from existing renewable facilities nor interfere with the integration of new renewable generation, and (c) take into account these factors to ensure a reduction of system-wide GHG emissions and support the goals and policies of AB 32.

The proposed project is a combined heat and power facility and not purely a power plant. But, it would meet conditions (a) and (c) while it is not clear if BP Watson [Watson Project] would meet condition (b). As a base load facility with a proposed 95 percent capacity factor, the BP Watson project [Watson Project] is not expected to be dispatchable, especially if it is able to achieve this hoped-for very high capacity factor. However, it does not follow that BP Watson [Watson Project] will interfere with development or integration of renewable generation into the electricity system.

The Avenal precedent decision may not be appropriate for this project because BP Watson [the Watson Project] is a combined heat and power (CHP) natural gas/refinery gas project, not a conventional natural gas power plant. Given the project's location in a heavy load pocket, the need to provide the refinery with a reliable steam source, and the likelihood that the facility would significantly reduce the possibility of refinery upsets due to loss of steam or power, staff believes that these other attributes rather than the Avenal precedent decision should apply. Furthermore, to the degree that electricity produced by BP Watson [the Watson Project] reduces the demand for electricity sales from SCE to the refinery located onsite, the project would assist in the attainment of the renewables target of 33 percent renewables sales by reducing sales to the host site, just as an efficiency improvement helps meet the RPS goal by reducing electricity sales.

In addition, BP Watson [the Watson Project] will be consistent with the GHG reduction goals in the AB32 Scoping Plan.

2.2 Noteworthy Benefits of the BP Watson Project [Watson Project]

Electricity is produced by operation of inter-connected generation resources and by knowing the fuel used by the generation sector, the resulting GHG emissions can be known. Operation of one power plant, like the BP Watson project [Watson Project], affects all other power plants in the interconnected system. The operation of BP Watson [the Watson Project] facility will have an impact upon system operation and GHG emissions in several ways:

- BP Watson [The Watson Project] will be consistent with CHP goals in the AB32 Scoping Plan.
- The BP Watson project [Watson Project] would facilitate to some degree the replacement of high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's new Emissions Performance Standard.
- The BP Watson project [Watson Project] could facilitate to some extent the replacement of generation provided by aging and once-through cooling power plants.
- The BP Watson project [Watson Project] would help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

The BP Watson project [Watson Project] would be used in a base load mode of operation to provide for onsite process steam needs. By cogenerating steam and electricity, BP Watson [Watson Project] would emit less GHG emissions than separate production of the same steam and electricity. BP Watson [The Watson Project] would not provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation. And, the high reliability of the BP Watson [Watson Project] facility would significantly reduce the possibility of refinery upsets due to loss of steam or power.

Despite the lack of dispatchability, as a new increment of power production the project would provide competitively priced electricity in the form of base load energy for sale to electric service providers to help meet expected electrical demand growth in Southern California.

The project would likely lead to a net reduction in GHG emissions from entities providing energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. Moreover, it would be consistent with AB 32 goals. The BP Watson project [Watson Project] would result in a reduction in GHG emissions from the electricity system.

The project would meet the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants, should the BP Watson [Watson Project] facility sell its power to a California electric Watson project would be required to seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed PPA, and any other conditions that dictate the operation of the BP Watson project [Watson Project]. The BP Watson project [Watson Project] as currently proposed meets the EPS of 0.500 metric tonnes CO2 per megawatt-hour.

No Conditions of Certification related to greenhouse gas emissions or GHG BACT, were proposed by CEC staff for the project.

The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.) and/or future GHG regulations formulated by the U. S. EPA or the ARB, such as GHG emissions caps and trade markets.

3.0 Part B – BP Watson's Greenhouse Gas BACT Evaluation

The primary basis for BP Watson's BACT analysis for greenhouse gases (GHG) anticipated to be emitted from the Watson Project is the CEC GHG Evaluation presented in the project *Final Staff Assessment, CEC 700-2011-002-FSA, August 2011* (Part A of this submittal), and the *Bay Area Air Quality Management District Responses to Public Comments on the Russell City Energy Center Federal PSD Permit, APN 15487, February 2010*.

As proposed, the Watson Project will be comprised of the following major systems that will have the potential to emit greenhouse gases, these are as follows: (1) 85 MW combustion turbine with duct-fired HRSG (5^{th} train addition), and electrical equipment containing SF_6.

3.1 Proposed GHG BACT

BP Watson is proposing the following as GHG BACT for the Unit #5 cogeneration combustion turbine/HRSG installation:

1. Use of state-of-the-art (as defined in the project description) combustion turbine technology coupled with modern duct firing technology in the HRSG (based on project design and objectives), in cogeneration mode.

2. Use of a combination of clean fuels, i.e., natural gas and refinery gas, which meet the regulations of the South Coast AQMD, as specified in the project design criteria.

3. Use of good combustion practices in both the turbine and duct fired HRSG.

4. Periodic inspection and proper maintenance of the turbine and duct fired HRSG to maintain the combustion equipment in a condition which reflects the most efficient operation, i.e., efficient fuel combustion versus power output and steam production, accounting for system age and degradation effects.

5. Maintain compliance with the Emission Performance Standard (Title 20, California Code of Regulations, section 2900, i.e., at a rate not to exceed 725 lbs of CO2 per megawatt-hour, calculated on a calendar year basis.

6. Comply with a CO_2e emissions limit of 827,884 short tons (752,622 metric tons) of CO_2e per calendar year (for Unit #5 only).

7. Monitor and report the net energy output on a calendar year basis.

8. Compute and report (via the DAHS), pursuant to the applicable regulations, the combustion related GHG emissions using the fuel type and fuel use consumption data, coupled with the emissions factors presented in the table below. The GHG emissions will be computed based on the calendar year fuel use of natural gas and refinery gas in Unit #5, and the following emissions factors:

Natural Gas	**Refinery Gas**
CO_2, 116.14 lbs/mmbtu	CO_2, 132.28 lbs/mmbtu
N_2O, 0.00022 lbs/mmbtu	N_2O, 0.001323 lbs/mmbtu
CH_4, 0.0287 lbs/mmbtu	CH_4, 0.00661 lbs/mmbtu
See SCAQMD PTC Application, 3/09, Section 5.0. Appendix I-A, Table I-A-10, and Tables C-1 and C-2 in the federal MRR regulations.	

Emissions computation for GHG from the turbine/HRSG systems are preliminarily based on the above noted emissions factors and predicted fuel use per the AFC. BP Watson may elect to calculate CO_2 emissions based on the current procedures used for Units 1-4 (See Appendix A for Unit #5 preliminary emissions estimates). The use of calendar years for the computation basis is consistent with the federal and CARB reporting periods under the applicable GHG monitoring and reporting programs.

9. BP Watson is proposing state-of-the-art enclosed-pressure SF_6 circuit breakers with a leak rate of less than or equal to 0.5% by weight on an annual basis, as BACT for the electrical breakers. Periodic inspection and preventive maintenance, coupled with a leak detection system will be used to insure that the proposed leak rate is not exceeded.

3.2 GHG BACT Analysis for the Turbine/HRSG

3.2.1 Step 1 Identify Potential Control Strategies.

Table 2 summarizes the potentially available control technologies for GHGs included for consideration as GHG BACT for the project.

Table-2 Summary of Technically Feasible GHG Control Technologies for the Turbine/HRSG

GHG Technology
Add-on GHG controls
Alternative generating technologies, Renewable energy technology (solar, wind, etc.)
Alternative fuels (other than those proposed)
Energy efficiency
Carbon capture and storage
Inherently lower-emitting GHG processes, practices, or designs, or combinations of the foregoing

EPA defines BACT as an emissions limitation 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.

EPA also states, in the NSR Workshop Manual, that, (1) a control technology that is demonstrated for a given type or class of sources is assumed to be technically feasible unless source-specific factors exist and are demonstrated to justify technical infeasibility, (2) technical feasibility of technology transfer control options is generally assessed based on an evaluation of the pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control has been previously applied, (3) innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis, and (4) the applicant is responsible for providing the basis for assessing technical feasibility or infeasibility and the reviewing authority is responsible for the decision on what is and is not technically feasible.

EPA notes in its March 2011 GHG Guidance document, that the requirement to consider inherently lower-emitting processes, practices, or designs does not require a fundamental redesign of the device, process, or source. As such, lower-emitting process/practices/designs that do not achieve the objectives, goals, or overall purposes of the project may be considered technologically infeasible as BACT for a specific project system or process.

Unlike other regulated air pollutants, which are often emitted as by-products of imperfect combustion and can be reduced by controlling the combustion process or through addition of add-on controls, at this time, there is no corresponding way to reduce the amount of CO_2 generated during combustion, as CO_2 is an essential product of the chemical reaction between the fuel and oxygen in which it burns. As such, the only way to reduce the amount of CO_2 generated by a fuel-burning cogeneration plant is to generate as much electric power and steam production as possible from combustion through the use of efficient generating technologies. BP Watson notes that natural gas (and refinery gas) produces about half as much CO_2 as coal and substantially less emissions of both criteria and toxic air pollutants as well. Based on the analysis presented herein, BP Watson believes that the proposed turbine/HRSG technology (firing a combination of natural gas and refinery gas) constitutes the most efficient cogeneration technology available for the Project that meets its objectives.

As a preliminary matter, BP Watson also considered inherently lower polluting processes that might be available for the general source category of electric power generation. This consisted of evaluation of several alternative generating technologies, none of which could meet the project objectives. BP Watson considered both renewable energy technologies (hydroelectric processes, geothermal power processes, ocean wave energy processes, energy from biomass, solar energy, wind energy), and other fossil-fuel energy technologies (conventional boiler and steam turbine, conventional simple-cycle combustion turbine, conventional combined-cycle power plants). In each case, however, these alternative generating technologies failed to meet fundamental project objectives and/or were not technically feasible and were therefore eliminated from consideration for the reasons described below. Indeed, EPA guidance provides that BACT will not ordinarily be applied to require an applicant to redefine its proposed project.

3.2.2 Step 2 Elimination of Technically Infeasible Options

Table 3 indicates the GHG technologies considered as identified in Table 1, and well as which technologies were applied or eliminated as a result of the BACT analysis for the project. Discussion of the various technologies, and their technical feasibility or infeasibility is presented below.

Table 3 GHG Technologies and Project Application Status

GHG Technology	Evaluation Status
Add-on GHG controls	Considered/Eliminated
Alternative generating technologies, Renewable energy technology (solar, wind, etc.)	Considered/Eliminated
Alternative fuels (other than those proposed)	Considered/Eliminated
Energy efficiency	Considered/Applied
Carbon capture and storage	Considered/Eliminated
Inherently lower-emitting GHG processes, practices, or designs, or combinations of the foregoing	Considered/Applied

3.2.2.1 Add-On Controls

Carbon capture begins with the separation and capture of CO_2 from the flue gas. Post-combustion capture systems under development are predicted to be capable of capturing 90+ percent of flue gas CO_2. Amine-based solvent systems are currently in commercial use for scrubbing CO_2 from industrial flue gases and process gases. However, these amine-based solvents have yet to be applied and demonstrated in practice with respect to the removal of the much larger volumes of CO_2 that are encountered in commercial scale power plants.

Solid sorbents can be used to capture CO_2 from flue gas through chemical adsorption, physical adsorption, or a combination of the two effects. Possible applications for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. Membrane-based systems utilize permeable or semi-permeable materials that allow for the selective transport/separation of CO_2 from flue gas. The process of separating CO_2 from flue gases has is characterized by high energy demands and high equipment and operational costs. In addition, the use of add-on controls would most likely only be employed as an integral part of a wider CCS strategy (see CCS discussion below).

3.2.2.2 Alternative Generating Technologies - Renewable Energy

BP Watson considered renewable generating sources as an alternative to the proposed Project. BP Watson believes that, due to their intermittent availability, there are no renewable energy projects that would meet the Project's objectives as stated above in the Project Description and the CEC FSA analysis.

BP Watson notes that, in conducting BACT analyses for power plants, permitting authorities have not typically considered whether renewable alternatives would achieve lower emissions and should therefore be required as BACT. Moreover, because of the intermittent availability of renewable energy generation technologies, they would fail to achieve a basic objective of the proposed project: to provide power and steam to meet the growing demand of the existing refinery operations.

The following summarizes select renewable generating technologies that were eliminated as alternatives for the Project.

3.2.2.2.1 Hydroelectric Processes

A hydroelectric project requires a flowing river or a series of reservoirs that could store water for a pumped storage project, requiring a large quantity of water. No such rivers or reservoirs exist in the immediate or regional vicinity of the proposed project. Therefore, the hydroelectric option is not feasible and was eliminated from consideration.

3.2.2.2.2 Geothermal Power Processes

Geothermal power plants use steam turbine facilities, for which the heat is generated by the high temperature and pressure geothermal fluids that are pumped from deep underground. Geothermal development is not viable at the Project location because suitable thermal vents and strata are not present. Thus, geothermal generation would not meet the Project's objectives and was eliminated.

3.2.2.2.3 Ocean Wave Energy Processes

Wave energy is generated by the influence of wind on the ocean surface. At the present time very few of these devices have been tested at full-scale and even fewer devices are ready for early adoption in commercial development projects. Therefore, this technology is not commercially available and cannot be considered technically feasible at this time.

3.2.2.2.4 Energy from Biomass

Energy production from a biomass power plant may come from the direct combustion of the biomass materials or from the conversion of the biomass into another fuel (such as alcohol or methane) and subsequent combustion of that fuel. The combustion process is used to heat steam boilers to generate steam for a steam turbine. Large quantities of the biomass "fuel" are not generated in the vicinity of the Project site and would need to be trucked or railed to the site. The storage and handling of the biomass would require additional space, and the power plant footprint would be larger than that for the proposed Project. Additionally, although classified as renewable, the emissions of criteria pollutants from a biomass power plant are, in many cases, significantly greater than the emissions from the proposed turbines/HRSGs burning natural gas and refinery gas. Moreover, as previously noted, the Project objectives include utilization of clean fuel(s), i.e., natural gas and refinery gas. Thus, construction of a biomass power plant instead of the proposed turbine/HRSG would defeat a Project objective. For all these reasons, although this technology is considered to be commercially available, it is not a feasible technology for the proposed Project and was eliminated from consideration.

3.2.2.2.5 Solar Energy

Most of these technologies collect solar radiation, heat water to create steam, and use the steam to power a steam turbine/generator. Photovoltaic technologies convert the sunlight directly into electricity. In both cases, power is only available while the sun shines, so the units do not supply power that can be flexibly used to follow refinery demands for power and steam. Thus, solar energy fails to meet the basic project needs and objectives. Additionally, the acreage required per MW generated is high, and not enough land is available at the Project site to deliver sufficient energy to meet project needs. Because a solar project would be inconsistent with the fundamental objective of providing power and steam for the existing refinery, solar generation technology is not an alternative to the Project and was eliminated from consideration.

3.2.2.2.6 Wind Energy

Based on current technology, the production of 85 MW of electrical power would potentially require between 22 and 30 wind turbines, spaced out along a substantial corridor with known wind resource capabilities. The project site is not suitable for wind energy development and therefore such technology is not feasible. Additionally, wind power does not meet the refinery steam and power operational needs and is fundamentally inconsistent with the project design and objectives as stated above, and therefore was not considered a feasible alternative for the project.

3.2.2.2.7 Nuclear Power Technology

Nuclear power alternatives are not considered as a feasible alternative for the Project and are not discussed further in this evaluation.

3.2.2.3 Alternative Fossil-Fuel Generating Technologies

BP Watson also evaluated several alternative fossil-fueled generating technologies that have been used to produce power and steam (cogeneration) in and out of California, i.e., boilers, and combined-cycle turbines. These alternative generating technologies were rejected for failing to achieve fundamental project objectives. In general, these technologies are commercially available. However, because of their relatively low efficiencies, i.e., btu/kW-hr and higher fuel use rates, i.e., btu/lb-steam produced, and higher overall GHG emissions potentials (due to increased fuel use), these alternatives were eliminated from consideration as part of this BACT analysis. Each of these alternatives is briefly discussed below.

3.2.2.3.1 Conventional Boiler and Steam Turbine

Conventional boiler and steam turbine technology generates high pressure steam by burning fuels in the furnace of a conventional boiler. This technology is well established and has been used in countless power and steam production plants worldwide. Typical thermal efficiencies of up to approximately 36 percent can be achieved by Boiler/Steam Turbine plants when utilizing natural gas. Turbines equipped with duct fired HRSGs typically have thermal efficiencies at or above 50 percent. The conventional boiler and steam turbine technology does not meet project needs because the sizing of a boiler to meet both the power and steam demands of the refinery would be unrealistic based on a comparison of fuel use and efficiency, i.e., in terms of btu/kW-hr and btu/lb steam produced. In addition, the space requirements, and increased water use requirements for a conventional boiler and steam turbine, make this alternative not feasible when considering the project needs and objectives. For these reasons, use of a conventional boiler and steam turbine is inappropriate and was rejected from consideration for the Project.

3.2.2.3.2 Simple-Cycle Combustion Turbine

Simple-cycle combustion turbine technology would not meet a fundamental project objective of providing additional steam to the refinery. For this reason simple-cycle combustion turbine technology was not considered as a feasible alternative for the project.

3.2.2.3.3 Combined-Cycle Power Plant

A combined-cycle power plant integrates combustion turbines (equivalent to the simple-cycle combustion turbine-generator) and steam turbines to improve the overall power plant efficiency, relative to a simple-cycle plant, by capturing and utilizing waste heat from the combustion turbines to generate additional power in the steam turbine. The combustion turbine's hot exhaust is passed through a heat recovery steam generator (HRSG) to create high pressure steam which is then used to drive a steam turbine-generator. This technology is able to achieve high thermal efficiencies, typically in the 50 to 57 percent under a steady-state operation. The high efficiency resulting from the additional heat recovery and power generation systems is achieved when these systems are at their normal operating temperatures and pressures. Thus, a combined-cycle power plant is more appropriate as an intermediate to base load power plant, and is not an appropriate choice for providing electricity and steam for the existing refinery. It should be noted that the proposed system is very similar to a combined-cycle plant, but the HRSG steam production is not used for additional power generation, but rather for refinery steam needs. Use of a combined cycle configuration would require extensive re-design of the turbine and HRSG in order to properly match the refinery power and steam needs, i.e., a smaller turbine coupled to a small steam turbine, with a substantially larger HRSG and duct firing system to make up for the refinery steam demand. Because combined-cycle technology is inconsistent with the Project's intended purpose, it was not considered as part of this BACT analysis.

3.2.2.4 Alternative Fuels

Other fuels such as propane, LNG, and LS fuel oils were eliminated from consideration because the Project design specifically calls for the use of pipeline grade natural gas and refinery gas, i.e., BACT clean fuels. Accordingly, use of any other fuel would potentially defeat a project objective, i.e., power and steam generation using available clean fuels. Moreover, pipeline-grade natural gas, and to some extent refinery gas, are the best (cleanest) fuel choice with respect to all criteria pollutants under consideration. Thus, even if alternative fuel sources were available, they would be ranked lower than the proposed use of pipeline-grade natural gas, and potentially refinery gas. In addition, these other fuel sources would all be eliminated due to technical infeasibility for the Project. On-site propane storage would be impractical from the standpoint of tank number or tank sizes, safety and the constant need for deliveries, etc. LNG is not commercially available in the project region at this time. LS fuel oil does not match the design of the proposed turbines; nor would use of LS fuel oil constitute a clean fuel choice.

Emissions of carbon dioxide (CO_2) during fossil fueled combustion are strongly correlated to the amount of carbon in the fuel stream. As stated, a fundamental objective of the Project is to utilize pipeline grade natural gas and available refinery gas. Thus, specification of any other fuel would frustrate a fundamental project objective. Nevertheless, because the definition of BACT includes, among other things, "fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each … pollutant", BP Watson would note that, in comparison to all other potential fuels, natural gas and refinery gas will achieve the lowest emissions of CO_2 and other greenhouse gases. A comparison of emissions rate factors for the various fuels as presented in Table 4 shows that natural gas (and refinery gas), when used as a fuel in stationary sources, typically produces less CO_2 than other fuels.

Table 4 CO_2 Emission Factors for Various Fuels

	Stationary Source Factors	
Fuel	**CCAR, lb/gal**	**CCAR, lb/MMBtu**
Natural Gas	15.12	116.98
Refinery Gas	-	132.28*
LNG	9.63	-
LPG	13.11	139.24
Diesel #2	22.38	161.27
Gasoline	19.55	-
Residual Oil	25.99	173.72
Propane	12.57	139.04
Biodiesel	20.99	-
Wood-Biomass	-	200.49
Kerosene	21.54	159.41
Coal	-	206.04

Source: California Climate Action Registry (CCAR), General Protocol, V3.1, 1/2009, and Power Sector Protocol, V1.1, May 2009.
*based on a historical analysis of refinery gas analysis data as provided by BP on December 12, 2011.

Another fuel choice might include combustion of biomass, such as wood chips or agricultural waste. Biomass is considered a renewable fuel choice, however, BP Watson was not able to identify a biomass fuel source in large enough quantities in the vicinity to make such a plant viable. The California Energy Commission has noted that biomass plants are typically sized to generate less than 10 MW, which is substantially less than the capacity of the Project (~85 Mw). For this reason, combustion of biomass does not appear at this time to provide a feasible alternative to the proposed Project. Moreover, as previously noted, use of any other fuel than natural gas would frustrate the project objective of using clean fuels such as natural gas and refinery gas.

3.2.2.5 Carbon Capture and Storage (CCS)

Carbon capture (or compression), transport, and storage (CCS) is the term used to describe a set of technologies aimed at capturing carbon dioxide emitted from industrial and energy-related sources before it enters the atmosphere, compressing it, and injecting it deep underground in secure geological formations, and ensuring it remains stored there indefinitely. EPA states, in the guidance noted above, that CCS is not in widespread use at this time, but that EPA generally considers CCS to be an "available" add-on pollution control for large CO_2-emitting facilities with high-purity CO_2 streams. EPA further states while CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. In particular, EPA notes that there are significant logistical hurdles that may preclude its application to a particular project or site, warranting its elimination from the BACT analysis at Step 2. BP Watson agrees with EPA and concludes, for the reasons explained below, CCS is technologically infeasible for the proposed Project and, even if it were available at this time, would likely be cost prohibitive.

The key driving force behind undertaking CCS is the need to find cost-effective solutions to tackle the global issue of climate change by reducing CO_2 emissions in a world where there is a continued and rising demand for energy. CCS has an important role to play as a bridge to a low-carbon energy future. However, CCS faces a number of challenges, the biggest of which is how to best demonstrate that CCS is safe, effective and can be done now at industrial scale at a competitive cost. Large scale pilot and demonstration projects will play an important role in showing that the integrated process can work, from capture through to storage. These demonstrations and accompanying research and technology development require substantial investment but will ultimately drive down costs while helping identify the most appropriate technologies, equipment and skills needed to use them. Additionally, a regulatory framework is needed for CCS to clarify, both at national and international levels, the long-term rights, liabilities and technical requirements as to how CCS will be undertaken.

Over 90% of the CO_2 produced by fossil fuels at large fixed installations can be captured and prevented from reaching the atmosphere. The three main technology types - pre-combustion, post-combustion and oxy-firing - are available, allowing CO_2 to be captured from industrial processes such as power generation, oil refining and cement manufacture.

Pre-combustion capture involves partial combustion of CO_2 to produce hydrogen and CO_2. Hydrogen combustion produces no CO_2 emissions, with water vapor being the main by-product. The component parts of pre-combustion technology exist today at commercial scale; the challenge now is to integrate these in a power application.

In post-combustion capture, the CO_2 is removed after combustion of the fossil fuel. CO_2 is captured from exhaust gases and other large point sources. Post-combustion can be installed on both new and existing power plants, which is important given that the average power plant operates for 40 years. The challenge around post-combustion is scale-up of the technology to commercial scale in a power/steam application, as well as integration (see discussion of add-on controls above).

Today, CO_2 is transported by truck, ship or pipeline. However, to transport the large amounts of CO_2 from power plant emissions, pipelines are the only practical solution. The pipeline transportation process is well understood as CO_2 pipelines have been used since the 1970s, transporting large volumes of CO_2 to oil fields for enhanced oil recovery (EOR). For example, US pipeline infrastructure has the capacity to safely and reliably carry 50 million tons of CO_2 a year.

The oil and gas industry has years of experience injecting CO_2 underground into geological formations for EOR. Oil and gas have remained underground for millions of years. The same natural conditions allow injected CO_2 to be stored securely. Once CO_2 is injected deep underground (typically more than 800 meters) it is absorbed and then trapped in minute pores or spaces in the rock structure. Impermeable cap-rock acts as a final seal to ensure safe long-term storage.

Structural trapping - at the storage site the CO_2 is injected under pressure deep down into the ground until it reaches the geological storage formation. The rocks of the storage formation are like a rigid sponge; they are both porous and permeable. Fluid CO_2 tends to rise towards the top of the formation until it reaches an impermeable layer of rock overlying the storage site. This layer, known as the cap-rock, securely traps the CO_2 in the storage formation. Structural trapping is the same mechanism that has kept oil and gas securely stored under the ground for millions of years.

Residual trapping - another natural process further traps the CO_2. As the injected CO_2 moves up through the geological storage site towards the cap-rock some is left behind, trapped in the microscopic pore spaces of the rock. This process is similar to air becoming trapped in a sponge.

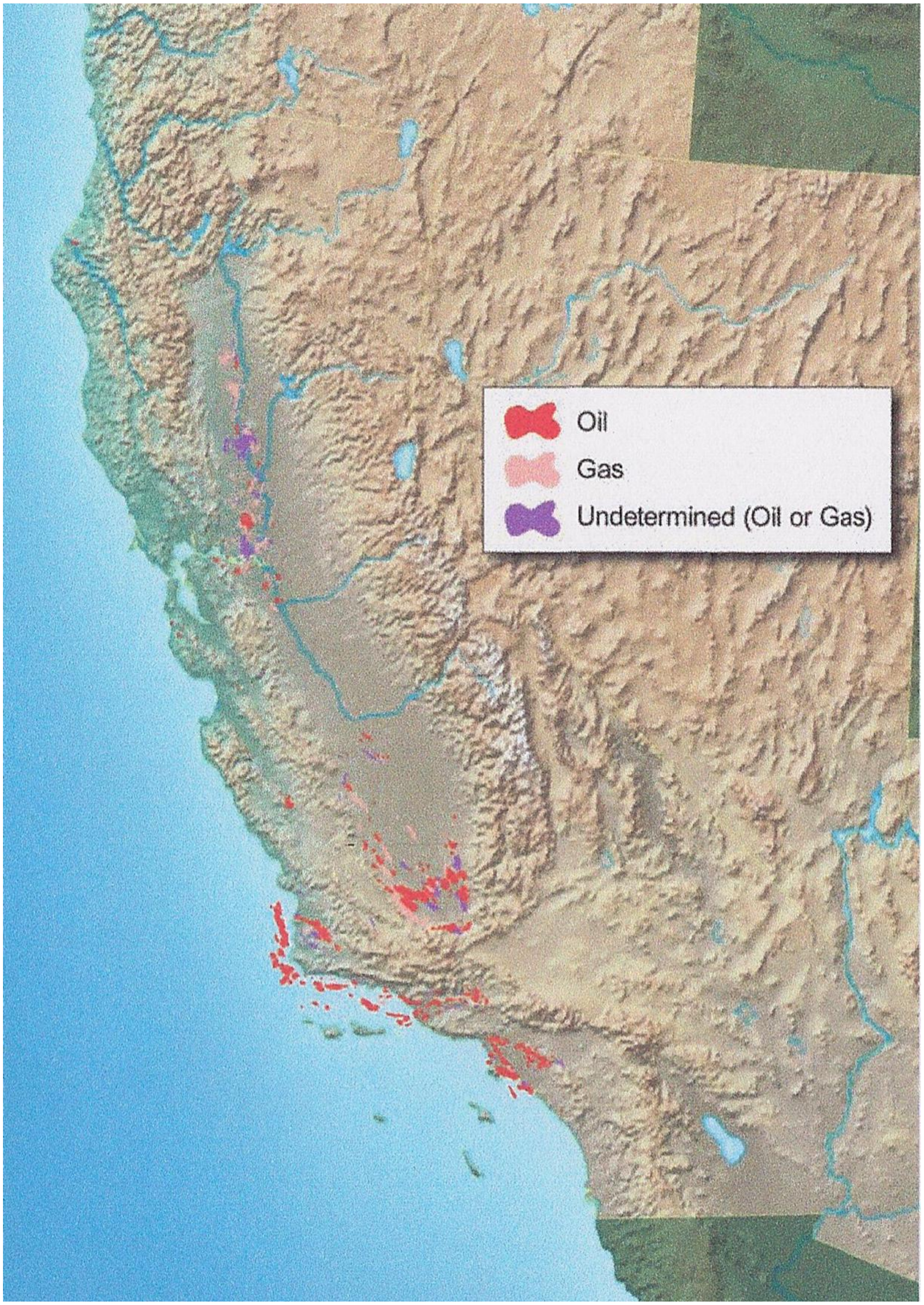
Dissolution and mineral trapping – two additional mechanisms also trap CO_2. Over time the CO_2 stored in a geological formation will begin to dissolve in the surrounding salty water. The salty water combined with the CO_2 becomes heavier and sinks towards the bottom of the formation over time. This is known as dissolution storage. Mineral storage occurs when the CO_2 held within the storage site binds chemically and permanently with the surrounding rock. Depleted hydrocarbon reservoirs, such as oil and gas fields, are highly suited to such geological storage of CO_2. Other potential storage sites are saline formations (permeable rock formations, which contain salty waters in their pore spaces), and unminable coal beds. According to the Intergovernmental Panel on Climate Change (IPCC), such geological formations could provide storage space for at least 2,000Gt (billion metric tonnes) of CO_2.

3.2.2.5.1 Feasibility of CCS for the Proposed Project

BP Watson is unaware of instances where CCS has successfully been applied to this type of project/fuel source using a similarly sized cogeneration power/steam plant. CCS therefore cannot be considered to constitute a demonstrated technology for the proposed source at this time. While EPA's March 2011 Guidance indicates that EPA would generally consider CCS to be an available technology, according to this guidance, the determination of whether CCS is technically feasible for any individual project involves consideration of all three main components of the process: CO_2 capture and/or compression, transport and storage. If these three components cannot be integrated into the base facility, then CCS may be eliminated from consideration as infeasible. BP Watson is aware that sequestration facilities are known to exist in the project region, but notes that access to such facilities is not an option for BP at this time. BP Watson notes that some study on this issue has been completed by the National Energy Technology Laboratory (NETL), and several potential sequestration sites have been identified in the regional area, as delineated on Figure 4 (*National Energy Technology Laboratory, NETL, 2010 Carbon Sequestration Atlas of the United States and Canada, 3rd Edition, 2010*). Further, there currently exists no adequate infrastructure for the transport of any captured carbon to sequestration basins elsewhere. Thus, for logistical reasons, implementation of CCS at the Project site would be infeasible, even if the technology for CO_2 capture from natural-gas fired emissions streams were commercially available at this time. Moreover, all available information surveyed by the Applicant indicates that most CCS technologies are not yet commercial and are not expected to become commercially available for 10 to 20+ years.

Additionally, the regulatory regime governing CO_2 injection and future liability is in its infancy, posing additional regulatory hurdles to the feasibility of CO_2 for the Project site.

Figure 4
Potential CO_2 Sequestration Sites in Southern California



In addition to these logistical hurdles, which render CCS an infeasible option for the Project at this time, another major impediment to implementation CCS would be the significant cost associated with capturing the flue gas (use of add-on control and capture systems), which can amount to up to 75% of the total cost of CCS. Recent studies conducted by MIT researchers *(The Cost of Carbon Capture, J. David and H. Herzog, MIT, Cambridge, MA)*, indicated that the range of CCS costs ($/metric ton) for technologies such as IGCC, PC, and NGCC plants was approximately $18 to $41. Assuming a $40/metric ton cost and based on an estimated CO2 emissions rate from the plant combustion related processes of approximately 695,305-744,989 metric tons/year (turbine/HRSG only), the cost for implementation of CCS could be approximately $27.8 to $29.8 million per year in equipment and operational costs.

CCS was preliminarily evaluated in the context of the Carson Hydrogen Power (CHP) which was a proposed 500 MW integrated gasification combined cycle (IGCC) power plant with 90 percent capture, which would have sequestered over 2 million metric tons of CO2 annually. The project, announced by a partnership of BP Alternative Energy and Mission Energy in 2006, was to be sited in Carson, California, adjacent to several oil refineries and to the Wilmington oil field, a sufficiently depleted oil reservoir that could potentially serve as a geologic storage reservoir. Carbon dioxide was also to be used to support EOR operations, thus offsetting project costs. The project team began considering alternative site locations in the fall of 2007, because of its inability to obtain a commercial agreement with the operator of the Wilmington field on the purchase of CO2 for EOR operations. In 2008, the lack of agreement with the operator of the Wilmington oil field resulted in a commercial decision by project sponsors to halt the CHP project. This impediment to CCS still represents a significant hurdle to the current project as well. (*World Resources Institute, CCS and Community Engagement, Guidelines for Community Engagement in Carbon Capture, transport, and Storage Projects, November 2010.*)

As acknowledged by EPA in its March 2011 Guidance, "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls", per the March 2011 Guidance. Thus, EPA anticipates that CCS will often be eliminated as too costly at Step 4 of the analysis, even in cases where feasible. BP Watson is unaware of any circumstances that would make CCS a less costly or more viable option for the project, *e.g.*, proximity to enhanced oil recovery fields, developed sequestration basins or existing pipeline infrastructure. Accordingly, BP Watson believes that, even if CCS were feasible for the Project at this time, it would be eliminated from consideration due to excessive cost.

3.2.2.6 Inherently Lower Emitting Technologies

As stated above, BP Watson believes that the choice of turbine and HRSG technologies, when operated in cogeneration mode, represents the best choice of inherently lower emitting technologies which meets the design and project objectives as defined in the project description.

3.2.3 Step 3. Rank the Technically Feasible Control Technologies by Control Effectiveness

As suggested previously, the amount of CO_2 and other GHGs emitted during combustion of fossil fuels is directly correlative to the amount of fuel consumed. Thus, the only available means of reducing emissions of CO_2 from the generation of power is to reduce the amount of fuel consumed per unit of energy generated. Accordingly, a comparison of various generating technologies' relative efficiency – or "heat rate" – may provide an appropriate basis for comparing and ranking the control efficiency of such technologies. For the Project, the only fuels to be used in the power generation cycle will be natural gas and refinery gas. Because the project is proposing to use two fuels, i.e., natural gas and refinery gas, and the fact that these fuels will be used in a wide range of combinations in the turbine and duct burners, setting an overall "heat limit value becomes problematic. Notwithstanding the foregoing, Project staff has produced the following tables which are instructive in reviewing the basis for a heat rate limit (*AFC, Section 3.4.5.3, Tables 3-3 and 3-21, 2009*):

AFC Table 3-3 Project Performance

	59ºF/60 Percent Relative Humidity		
	Unfired HRSG	**Minimum Fired**	**Maximum Fired**
Steam Production, lb/hr	339,143	375,670	659,293
Net Project Output, MW	85.770	85.712	85.263
CTG Heat Input, MMBtu/h (LHV)	925.9	925.9	925.9
Duct Burner Heat Input, MMBtu/h (LHV)	0	41.0	383.6
Total Project Heat Input, MMBtu/h (LHV)	925.9	966.9	1,309.5
Net Project Heat Rate, Btu/kWh (LHV)	10,795	11,280	15,358
Net Project Heat Rate, Btu/kWh (HHV)	11,947	12,482	16,973
Heat Rate Chargeable to Power, Btu/kWh (HHV)	6,603	6,558	6,543

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
Performance with foggers on.
ºF = degrees Fahrenheit
Btu/kWh = British thermal units per kilowatt hour
CTG = combustion turbine generator
HHV = higher heating value
HRSG = heat recovery steam generator
lb/hr = pounds per hour
LHV = lower heating value
MMBtu/h = million British thermal units per hour
MW = megawatt

AFC Table 3-21 Cogeneration Efficiency

	Electrical Energy (kW)	**Hourly Energy (MMBtu/ hour)**	**Annual Capacity Factor**	**Annual Energy (Billion Btu)**
Useful Thermal Energy - Desuperheated Steam to Watson Cogeneration Company		903.2	0.95	7,496
One-half of Useful Thermal Energy Output		451.6	0.95	3,748
Net Plant Electrical Output (Useful Power Output)	85,263	291.2	0.95	2,420
Total Energy Output		1194.4		9,916
Useful Thermal Energy, Percent of Total Energy Output		75.6%		75.6%
A. Power Output Plus One-half the Useful Thermal Output		742.8		6,168
B. Natural Gas/Refinery Gas Energy Input		1,309.5		10,878
Line A / Line B		56.7%		56.7%

Kiewit Power Engineers Co., 2009.
*Based on Heat Balance Case E-6 (Maximum Fired Duct Burner).
Btu = British thermal unit
kW = kilowatt
MMBtu = million British thermal units per hour

Due to complex nature of the operation of the Unit #5 cogeneration system with respect to the firing of duel fuels in both the turbine and HRSG, coupled with the possible dispatch scenarios for both heat (steam) and power, the use of a "heat rate" limit was not considered as practically feasible for the Unit #5 project considering combined heat and power (CHP).

The Project is therefore proposing to minimize GHG emissions in its generation of power and steam by using natural gas and refinery gas in highly efficient gas turbine/HRSG duct firing technology with a reasonably low heat rate and high efficiency across the Project's entire operational range.

Table 5 presents a generalized ranking of the identified generation technologies based on their known ranges of heat rates, as considered in the BACT analysis for this project.

Table 5 Ranking of Potential Technologies by Heat Rate

Technology	Heat Rate Range (HHV basis)	Technologically Feasible for This Project?
Renewable energy sources	n/a	No
Nuclear power	n/a	No
Biomass and other biofuels	n/a	No
CCS	n/a	No
Cogeneration (turbine w/HRSG)	Variable depending on project design and fuels	Yes
Combined cycle turbines	~7000-8000 btu/Kw-hr	Possibly (but only after significant project re-design)
Reciprocating IC engines	~7500-8600 btu/Kw-hr	No
Simple cycle turbines	~8500-10000 btu/Kw-hr	No
Boilers	>10000 btu/Kw-hr	Possibly (but only after significant project re-design)

Table 6 presents a comparison of various power plant facility heat rates and GHG performance as prepared by CEC staff in March 2011. This data is primarily for combined cycle turbines and boilers. BP Watson has added data for the Unit #5 Project, and for reciprocating engines, as well as data on simple-cycle turbine applications for purposes of comparison.

Table 6 Power Plant Heat Rates and GHG Performance

Facility	Heat Rate, Btu/kWh	Est. Energy Output, GWh	GHG Performance, MTCO2/MWh
Watson Project	<=6543[1]	~744.6	~0.318
Quail Brush (Rice)	8600	~412.5	~0.464
Eastshore (Rice)	8898	~462	~0.463
Mariposa Energy (SC)	9450	800	~0.541
EME Walnut (SC)	8595	2000	~0.481
Gateway GS (CC)	7123	2490.2	~0.378

Facility	Heat Rate, Btu/kWh	Est. Energy Output, GWh	GHG Performance, MTCO2/MWh
Los Medanos EC (CC)	7184	3394.7	~0.381
Delta EC (CC)	7308	5013.5	~0.387
CCPP #6 (Blr)	13499	21.1	~0.716
CCPP #7 (Blr)	11182	176.9	~0.593
PPP #5 (Blr)	11461	103.3	~0.608
PPP #6 (Blr)	11918	84.4	~0.632
PPP #7 (Blr)	14629	29.3	~0.776

RICE-reciprocating internal combustion engine(s)
[1] actual heat rate for the two fuels and firing combinations is highly variable (power production only). This value is shown for comparison purposes only, a heat rate limit is not currently proposed (see discussion above).

At the present time, combined cycle plants utilizing efficient turbines, HRSGs, and clean fuels certainly represent the highest efficiencies with respect to fuel burned versus power produced. But, a combined cycle plant does not always “fit the bill” when cogeneration (power and steam) is what is needed, and does not meet this Project’s objectives.

Beyond consideration of the power/steam cycle, another important component of the GHG BACT analysis is the efficiency of load-consuming elements of the overall plant design. The more efficiently the plant consumes energy, the more energy that can be provided to produce power and steam, resulting in lower emissions of GHGs per MWh of energy provided, or per pound of steam to the refinery. As a consequence, BP Watson plans to utilize modern equipment for such process items as fans, pumps, etc., and will also consider the efficiency of other major components of plant design. Examples of equipment choices would be; (1) use of variable speed fans or pumps where feasible and safe, (2) use of efficient lighting, etc. Evaluation of these components is an integral part of the plant design process, i.e., design engineering will strive to minimize plant auxiliary loads, thus maximizing the efficiency of the load-consuming elements. Whenever possible, the auxiliary equipment will be evaluated pursuant to the established *Energy Star* guidelines (www.energystar.gov).

Table 7 presents the ranking of the GHG technologies deemed feasible for the proposed project. While these technologies are “ranked” in order of their presentation, they are more appropriately considered as a suite of measures that will be implemented to assure that the proposed Project generates and consumes power and steam in the most efficient manner and thereby achieves BACT for GHGs.

Table 7 GHG Technology Ranking for the Project

Technology	Ranking	Applied to Project
Use of inherently lower emitting processes (turbine w/HRSG duct firing in cogeneration mode)	1	Yes
Clean Fuels		
Energy Efficiency		
Good combustion practices and preventive maintenance		

Based on the foregoing, BP Watson believes that the cogeneration system (turbine and HRSG with duct firing) utilizing efficient system designs and firing clean fuels such as natural gas and refinery gas, represents the most efficient system in terms of GHG emissions for the proposed Project as defined.

3.2.4 Step 4. Environmental, Energy, and Economic Feasibility of Control Options

Because the Watson Project is proposing to utilize all of the feasible technologies (as presented in Table 7) for reducing GHGs from the cogeneration project, no detailed analysis is provided to compare the available control technologies' relative environmental, energy and economic impacts. Comments on the cost implications of CCS are presented in Section 3.2.2.5.1 above.

3.2.5 Step 5. Select BACT

As indicated above, the Watson Project is proposing the use of cogeneration technology (turbine w/HRSG duct firing), clean fuels, and efficient design of load-consuming equipment as BACT for the proposed Project. The Watson Project will also maintain the efficiency of the combustion systems by employing proper maintenance practices and procedures, and using good combustion practices.

The technology selected as BACT at Step 5 must be translated into an enforceable emissions limitation by the permitting agency. In its March 2011 Guidance, EPA encouraged permitting authorities to consider establishing output-based limits or a combination of both output- and input-based limits. EPA noted that, because the environmental concern related to GHG emissions is their cumulative impacts, the focus in establishing limits should be on longer-term averages, rather than short-term averages. Examples of long term averaging periods would be; (1) 12 month rolling averages, (2) calendar year averages, etc. BP Project staff will work with agency personnel to establish appropriate BACT limits for the Unit #5 combustion systems and auxiliary load-consuming elements that affect efficiency.

Proposed BACT for the Turbine/HRSG:

1. Use of state-of-the-art (as defined in the project description) combustion turbine technology coupled with modern duct firing technology in the HRSG (based on project design and objectives), in cogeneration mode.

2. Use of a combination of clean fuels, i.e., natural gas and refinery gas, which meet the regulations of the South Coast AQMD, as specified in the project design criteria.

3. Use of good combustion practices in both the turbine and duct fired HRSG.

4. Periodic inspection and proper maintenance of the turbine and duct fired HRSG to maintain the combustion equipment in a condition which reflects the most efficient operation, i.e., efficient fuel combustion versus power output and steam production, accounting for system age and degradation effects.

5. Maintain compliance with the Emission Performance Standard (Title 20, California Code of Regulations, section 2900, i.e., at a rate not to exceed 725 lbs of CO2 per megawatt-hour, calculated on a calendar year basis.

6. Comply with a CO_2e emissions limit of 827,884 short tons (752,622 metric tons) of CO_2e per calendar year (for Unit #5 only).

7. Monitor and report the net energy output on a calendar year basis.

8. Compute and report (via the DAHS), pursuant to the applicable regulations, the combustion related GHG emissions using the fuel type and fuel use consumption data, coupled with the emissions factors presented in the table below. The GHG emissions will be computed based on the calendar year fuel use of natural gas and refinery gas in Unit #5, and the following emissions factors:

Natural Gas	Refinery Gas
CO_2, 116.14 lbs/mmbtu	CO_2, 132.28 lbs/mmbtu
N_2O, 0.00022 lbs/mmbtu	N_2O, 0.001323 lbs/mmbtu
CH_4, 0.0287 lbs/mmbtu	CH_4, 0.00661 lbs/mmbtu
See SCAQMD PTC Application, 3/09, Section 5.0. Appendix I-A, Table I-A-10, and Tables C-1 and C-2 in the federal MRR regulations.	

Emissions computation for GHG from the turbine/HRSG systems are preliminarily based on the above noted emissions factors and predicted fuel use per the AFC. BP Watson may elect to calculate CO_2 emissions based on the current procedures used for Units 1-4 (See Appendix A for Unit #5 preliminary emissions estimates). The use of calendar years for the computation basis is consistent with the federal and CARB reporting periods under the applicable GHG monitoring and reporting programs.

3.2.6 Consideration of Continuous Emissions Monitoring System for Carbon Dioxide

BP Watson is presently considering whether emissions of CO_2 should be monitored through use of a continuous emissions monitoring system (CEMS). While BP Watson acknowledges that Part 75 and, as a consequence, the Air Resources Board's mandatory reporting rule allow the facility to measure CO_2 as a diluent gas, rather than oxygen (O_2), and use these data as the basis for the required reports, there is no substantial justification for obtaining direct measurements of CO_2 in the effluent stream, as there is for other pollutants. Rather, as explained previously, CO_2 is an unavoidable byproduct of the combustion process; the amount of carbon within the fuel will all ultimately be emitted as CO_2.

Unlike emissions of NO_x or carbon monoxide, which are heavily influenced by the conditions in which combustion occurs and can be controlled by adjusting those conditions (e.g., combustion temperature, amount of air present in combustion chamber), CO_2 emissions are not significantly influenced by the conditions of combustion. Therefore, while measurements of actual stack gas concentrations of NO_x are generally more accurate than application of emissions factors, BP Watson does not believe there is any apparent reason why direct measurements of CO_2 in the stack gas should be any more accurate than calculation of CO_2 through application of the relevant emissions factor to fuel usage data. Thus, for purposes of quantifying the facility's mass emissions of CO_2 (or CO_{2e}), BP Watson is not proposing actual stack gas measurements of the concentrations of CO_2 (or any other GHG such as CH4 or N2O) in the effluent stream. Based upon the finalization of BP Watson's evaluation of potential CO_2 monitoring via CEMS, the use of CEMS may be proposed as the primary option for emissions monitoring and quantification in lieu of using emissions factors and fuel use.

3.2.7 BACT for Electrical Equipment Containing SF_6

In addition to emissions of greenhouse gases from the cogeneration power plant, the proposed facility will also consist of high-voltage circuit breakers which use sulfur hexafluoride (SF_6) as a gaseous dielectric. SF_6 is the most highly potent greenhouse gas, with a "global warming potential" over a 100-year period 23,900 times greater than carbon dioxide (CO_2) and an estimated persistence in the atmosphere for 3,200 years.

Because of SF_6's high global warming potential, the California Air Resources Board (Air Resources Board) has promulgated one "discrete early action" item addressing emissions of SF_6 from sources outside of the electric generating and semiconductor sectors. The Air Resources Board is also scheduled to develop an additional "early action" measure specifically focused on achieving reductions in SF_6 emissions from the electrical generating sector.

While there are no mandatory rules regulating electric sector emissions of SF_6 at this time, the U.S. Environmental Protection Agency (EPA) has, since 1999, led a voluntary public-private partnership known as the "SF_6 Emission Reduction Partnership for Electric Power Systems" ("EPA SF_6 Partnership"), which has targeted reductions in SF_6 emissions within the electric utility industry, tracks utilities' progress towards achieving those reduction goals, and shares information among members on their respective efforts to achieve reductions. As part of these efforts, EPA has estimated an upper and lower bound weighted-average leakage rate for SF_6 from circuit breakers of 2.5% and 0.2%.

The proposed Unit #5 facility will include a switchyard with circuit breakers, containing SF_6. According to EPA's research, emissions from circuit breakers can be easily tracked by the occurrence of "top-ups", i.e., the replacement of lost SF_6 with new product."

To evaluate the "best available control technology" for emissions of SF_6 from the facility, the BP Watson followed U.S. EPA's "top-down" methodology.

3.2.7.1 Step 1: Identify Control Technologies for SF_6

Technologies identified are as follows:

1. <u>Use of Other Gases/Substances for Insulation and Arc Quenching</u>

The best way to control emissions of SF_6 would be to eliminate its use in the circuit breakers and substitute in its place a non-hazardous substance that does not have comparable emissions of greenhouse gases. One alternative to SF_6 would be use of a dielectric oil or an compressed air ("air blast") circuit breaker, which represented the type of breakers historically used in high-voltage installations, prior to the development of SF_6 breakers. However, according to numerous sources, SF_6 circuit breakers are the breaker type predominantly used in the high-voltage and extremely high-voltage range.

According to the most recent report released by the EPA SF_6 Partnership, no 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. Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications. While some progress has reportedly been made using mixtures of SF_6 and other inert gases (e.g., nitrogen or helium) in medium- or low-voltage applications, most studies have concluded that there are no replacement gases immediately available to use as an SF_6 substitute for high-voltage applications.

2. Modern Closed-Pressure SF_6 Breakers with Leak Detection

In comparison to older SF_6 circuit breakers, modern breakers use substantially less SF_6 and are designed as a totally enclosed-pressure system. According to information provided to BP Watson, the facility will have circuit breakers, containing a total of 5,870 pounds of SF_6. New circuit breakers are typically guaranteed by the equipment vendor with leakage of no more than 0.5-1% per year (by weight). Leakage is only expected to occur as a result of circuit interruption and at extremely low temperatures not anticipated in the South Coast Air Basin. BP Watson, based on data available from the circuit breaker manufacturer, believes the breakers will meet a gas leakage rate of less than 0.5% per year.

3.2.7.2 Step 2: Eliminate Technically Infeasible Options

As indicated above, SF_6 has become the predominant insulator and arc quenching substance in circuit breakers because of its superior capabilities, in comparison to other alternatives. A National Institute of Standards and Technology Technical Note (#1425) describes the benefits of SF_6 as follows:

"For circuit breakers the excellent thermal conductivity and high dielectric strength of SF_6, along with its fast thermal and dielectric recovery (short time constant for increase in resistivity), are the main reasons for its high interruption capability. These properties enable the gas to make a rapid transition between the conducting (arc plasma) and the dielectric state of the arc, and to withstand the rise of the voltage. SF_6-based circuit breakers are presently superior in their performance to alternative systems such as high-pressure air blast or vacuum circuit breakers. However, the greatest level of control for emissions of greenhouse gases would be achieved through use of circuit breakers that do not rely upon SF_6 for its insulating and arc quenching capabilities. While oil-filled or "air-blast" breakers are alternatives available for high-voltage systems, both of these options would require significantly larger equipment to replicate the same insulating and arcing capabilities of the SF_6 breakers proposed by BP Watson. In addition, BP Watson believes that the present site does not have adequate space within the existing switchyard to accommodate oil or air-blast breakers." *National Institute of Standards and Technology Technical Note (#1425).*

Based upon the Applicant's review of technical literature, replacement of SF_6 with another gaseous dielectric can be eliminated at Step 2, since existing research indicates that there is no replacement gas available at this time with comparable insulating and arc quenching capabilities. Additionally, mixtures of SF_6 and another gas are not feasible because, according to one source, "the use of such a mixture [e.g., with N_2] results in somewhat reduced interrupting capability relative to pure SF_6, and the breaker is often derated by one current interrupting class." Further, use of oil-filled or air-blast breakers does not qualify as a feasible alternative for the proposed project site, since there is not sufficient space at the proposed project site for location of the physically larger-sized breakers necessitated to achieve comparable arc quenching capability.

3.2.7.3 Step 3: Rank Control Technologies by Control Effectiveness

In the absence of feasible alternatives to use of SF_6, the next best control would be use of a new modern closed pressure circuit breaker that is guaranteed to leak 0.5% or less per year. SF_6 records at the existing cogeneration facility indicate an annual loss rate of approximately 38 lbs per year for the existing four (4) power trains and their associated electrical equipment. This loss rate equates to approximately 9.5 lbs/year per power train. Assuming a similar loss rate of 9.5 lbs/year for the proposed project electrical equipment, this would amount to potential emissions of SF_6 of 9.5 lbs/year, which due to SF_6's high global warming potential would equal approximately 103 metric tons CO_2E per year.

3.2.7.4 Step 4: Environmental, Energy, and Economic Feasibility of Control Options

Step 4 of the top-down analysis involves consideration of the ancillary energy, environmental and economic impacts associated with using the top-ranked control technologies. One reason for selecting SF_6 over oil dielectrics is the relative predictability of decomposition products, i.e., SF_6 starts out as a pure chemical, which forms a limited number of decomposition by-products as a result of reactions that can be predicted with some precision. The toxicity of the limited number of by-products can therefore be investigated and adequate precautions taken. Oil dielectrics, on the other hand, usually start out as hydrocarbon soup, with far too many compounds to predict the decomposition by-products, let alone their toxicity.

However, SF_6, too, may produce some toxic and corrosive products as a result of electrical discharges, according to most literature.

Although use of alternative breakers which use air or oil for insulating and arc quenching was eliminated as infeasible at Step 2, it would also result in significant environmental impacts associated with the additional land needed to site the physically larger breakers near the facility, the greater amount of noise generated by air or oil-filled breakers, and the potential for release of dielectric fluid to the environment and/or associated fires. According to one study, "[offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads." (NIST Technical Note 1425). Accordingly, even if such alternatives were not eliminated at Step 2 of the top-down analysis, they would likely cause ancillary environmental impacts that warranted their elimination for the Project site.

3.2.7.5 Step 5: Select BACT

BP Watson has concluded, that using totally enclosed circuit breakers of the number and size as proposed, coupled with a leak rate of less than or equal to 0.5%, constitutes BACT for this source. In addition, the proposed facility's product purchase and use records will provide a relatively accurate process for inventorying emissions of SF_6. Based upon BP Watson's review, a leak detection system is the standard method for measuring and reporting SF_6 emissions from circuit breakers.

<u>The proposed GHG BACT is as follows:</u>

1. BP Watson is proposing state-of-the-art enclosed-pressure SF_6 circuit breakers with a leak rate of less than or equal to 0.5% by weight on an annual basis, as BACT for the electrical breakers. Periodic inspection and preventive maintenance, coupled with a leak detection system will be used to insure that the proposed leak rate is not exceeded.

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24. *In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, at 51-52 (2003) (finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility", at 51-52; *see also In re Prairie State Generating Company*, PSD Appeal No. 05-05, 14 E.A.D. __, slip op. at 32 (2006) (referencing the EAB's recognition in *In re Kendall New Century Development* that "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility").

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30. The lower and higher figure reflect application of the emissions factors for CO_2 applicable under U.S. EPA's Climate Leaders program – 115.6 lb/MMBtu – and the Part 75 Acid Rain Monitoring Program, 118.9 lb/MMBtu. Other relevant emissions factors include the California Climate Action Registry's factor of 116.9 lb/MMBtu and the Air Resources Board's mandatory reporting rule, which applies emissions factors for CO_2 between 116.5 and 120.5 lb/MMBtu of natural gas, depending upon the Btu content of the gas stream. The Applicant would also note that it is following the convention of stating emissions of greenhouse gases in terms of "CO_2-equivalents" (CO_2E), which, for this source, include emissions of methane (CH_4) and nitrous oxide (N_2O) as well. These two pollutants have a higher "global warming potential" than CO_2, reflecting

their relative propensity to trap sunlight that would otherwise be reflected back into outer space within the Earth's atmosphere and thereby contribute to global warming. The emissions factors and global warming potentials for N_2O and CH_4 are specified by the Air Resources Board's mandatory reporting rule: For N_2O, the emissions are 0.00022 lbs/MMBtu and the global warming potential is 310; for CH_4, the emissions are 0.0020 lbs/MMBtu and the global warming potential is 21.

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EPA's GHG Mitigation Measures Database
http://www.epa.gov/nsr/ghgpermitting.html

EPA's Sector GHG Control White Papers
http://www.epa.gov/nsr/ghgpermitting.html

EPA's RACT/BACT/LAER Clearinghouse (RBLC)
http://cfpub.epa.gov/rblc/

ENERGY STAR Guidelines for Energy Management
http://www.energystar.gov/guidelines

ENERGY STAR Industrial Sector Energy Guides
http://www.energystar.gov/epis

EPA's Climate Leaders Protocols
http://www.epa.gov/stateply/index.html

Report of the Interagency Task Force on Carbon Capture and Storage
http://www.epa.gov/climatechange/policy/ccs_task_force.html

EPA's Lean and Energy Toolkit
http://www.epa.gov/lean/toolkit/LeanEnergyToolkit.pdf

EPA's Voluntary Partnerships for GHG Reductions:
Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
CHP Partnership Program (http://www.epa.gov/chp)
Green Power Partnership (http://www.epa.gov/greenpower)
Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
Voluntary Aluminum Industrial Partnership:
http://www.epa.gov/highgwp/aluminum-pfc/index.html

SF Emission Reduction Partnership for the Magnesium Industry
http://www.epa.gov/highgwp/magnesium-sf6/index.html

PFC Reduction/Climate Partnership for the Semiconductor Industry

http://www.epa.gov/highgwp/semiconductor-pfc/index.html
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DOE's Industrial Technologies Program (Best Practices)
http://www1.eere.energy.gov/industry/bestpractices/

EPA Energy Star Industrial Energy Management Information Center
http://www.energystar.gov/index.cfm?c=industry.bus_industry_info_center

DOE Industrial Technologies Program
http://www1.eere.energy.gov/industry/

Lawrence Berkeley National Laboratory Industrial Energy Analysis Program
http://industrial-energy.lbl.gov/

European Union Energy Efficiency Benchmarks
http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm

Appendix A
GHG Emissions Estimates

Calculation of GHG Emissions

Watson Cogen Expansion

Base Emissions Factors Compound	Turbine EF Nat Gas lbs/mmbtu	Turbine EF Ref Gas lbs/mmbtu	HRSG/DB EF Nat Gas lbs/mmbtu	HRSG/DB EF Ref Gas lbs/mmbtu	Turbine Calculated Blended Fuel EF lb/mmbtu	HRSG Calculated Blended Fuel EF lb/mmbtu
CO2	116.14	132.28	116.14	132.28	121.34515	132.28
CH4	0.0287	0.0066	0.0287	0.0066	0.021575975	0.00661
N2O	0.00022	0.00132	0.00022	0.00132	0.000576395	0.001323

Operating Scenarios, HHV	**1**	**2**	**3**	**4**	**5**
Turbine, mmbtu/hr NG	1062.05	0	0	1062.05	0
Turbine, mmbtu/hr RG	0	0	0	0	0
Turbine, mmbtu/hr Blend	0	1061.58	1061.58	0	0
HRSG, mmbtu/hr NG	0	0	447.94	447.94	0
HRSG, mmbtu/hr RG	447.94	447.94	0	0	0
HRSG, mmbtu/hr Blend	0	0	0	0	0
Operating Scenarios, hrs					
Turbine, hrs/yr NG	8760	0	0	8760	0
Turbine, hrs/yr RG	0	0	0	0	0
Turbine, hrs/yr Blend	0	8760	8760	0	0
HRSG, hrs/yr NG	0	0	8760	8760	0
HRSG, hrs/yr RG	8760	8760	0	0	0
HRSG, hrs/yr Blend	0	0	0	0	0

Fuel Data	
NG, btu/scf (HHV)	1028.05
RG, btu/scf (HHV)	1006.77

Blend Fuel Data	mmbtu/hr	Blend Factor
Turbine NG, %	67.75	0.6775
Turbine RG, %	32.25	0.3225
HRSG NG, %	0	0
HRSG RG, %	100	1

Emissions	**1**	**2**	**3**	**4**	**5**
CO2, lbs/yr	1.5996E+09	1.6475E+09	1.5842E+09	1.5362E+09	0.0000E+00
Methane, lbs/yr	2.9295E+05	2.2658E+05	3.1326E+05	3.7963E+05	0.0000E+00
N2O, lbs/yr	7.2475E+03	1.0552E+04	6.2273E+03	2.9233E+03	0.0000E+00
CO2e, lbs/yr	1.6080E+09	1.6555E+09	1.5927E+09	1.5451E+09	0.0000E+00
CO2e, tons/yr	8.0399E+05	8.2777E+05	7.9634E+05	7.7256E+05	0.0000E+00
CO2e, metric tons/yr	**723588.6**	**744989.4**	**716705.6**	**695304.8**	**0.0**

Footnotes and References Applicable to Calculations and Table

1. assumes SCR with COC on GT/HRSG

Natural Gas Emissions Factors

2. CCAR, Version 2.1, June 2006, natural gas emissions factors and carbon content adjustment.
3. EME-Greenhouse Gas Emission Factor Review, URS, 2003, CO2 emissions factors for natural gas and refinery gas.
4. ETC/ACC Technical Paper 2003/10, Comparison of GHG CO2 Emission Factors, July 2003

Refinery Gas Emissions Factors

5. CARB, GHG Inventory, N2O from Fuel Combustion-Refinery Gas (webpage), refinery gas N2O emissions factor. www.arb.ca.gov/cc/inventory/doc/docs1/1a1b_petroleumrefining_fuelcombustion_refinery/
6. Petroleum Industry Guidelines for Reporting GHG Emissions, 12/2003, IPIECA-OGP-API
7. BP supplied data, Refinery Fuel Gas to Merox, GHG Factor for CO2-5 Yr. Avg (see support data on next page)
8. fuel and emissions factor data supplied by BP 12-13-11, and 12-20-11.

SF6 Emissions Estimate

*Emissions based on inventory reconciliations for Units 1-4 for 2011.

Unit 1-4 SF6 losses for 2011 =	38.0	lbs/yr
Per unit loss rate for 2011 =	9.5	lbs/yr
Predicted SF6 loss rate for Unit 5 =	9.5	lbs/yr
SF6 GWP value =	23900.0	
CO2e Estimated Emissions =	227050.0	lbs/yr
	113.5	tons/yr
	103.2	metric tons/yr

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION
FOR THE *WATSON COGENERATION STEAM AND ELECTRICITY RELIABILITY PROJECT*

DOCKET NO. 09-AFC-1
PROOF OF SERVICE LIST
(Revised 10/28/11)

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*indicates change

DECLARATION OF SERVICE

I, Cindy Fischer, declare that on January 6, 2012, I served and filed copies of the attached *Greenhouse Gas BACT Analysis, dated December 2011*. The original document, filed with the Docket Unit or the Chief Counsel, as required by the applicable regulation, 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/watson/index.html]**.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(*Check all that Apply*)

For service to all other parties:

__X__ Served electronically to all email addresses on the Proof of Service list;

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AND

For filing with the Docket Unit at the Energy Commission:

_X__ by sending an original paper copy and one electronic copy, mailed with the U.S. Postal Service with first class postage thereon fully prepaid and e-mailed respectively, to the address below (***preferred method***); ***OR***

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

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OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
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I declare under penalty of perjury under the laws of the State of California 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.

CH Fischer

Cindy Fischer