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October 18, 2010

Mr. Kyrik Rombough
Natural Resources Engineering Director
Air Quality Program
South Dakota DENR
Joe Foss Building
523 East Capitol
Pierre, SD 57501

RECEIVED

OCT 19 2010

AIR QUALITY
PROGRAM

**Re: Hyperion Energy Center – Air Quality Preconstruction Permit # 28.0701
BACT Review for Greenhouse Gases**

Dear Mr. Rombough:

Enclosed please find a review of Best Available Control Technology ("BACT") for emissions of Greenhouse Gases ("GHG") from the Hyperion Energy Center. This review is being submitted in response to your letter dated September 27, 2010.

Should you have any questions or require additional information, please contact me at (919) 845-1422, extension 20.

Sincerely,

A handwritten signature in black ink, appearing to read "Colin M. Campbell", written in a cursive style.

Colin M. Campbell
Project Manager

Hyperion Energy Center

Best Available Control Technology Review for Greenhouse Gas Emissions

October 2010

RECEIVED

OCT 19 2010

**AIR QUALITY
PROGRAM**

Submitted to:

South Dakota Department of Environment & Natural Resources

Joe Foss Building

523 E. Capitol

Pierre, SD 57501

Prepared for:

Hyperion Refining LLC

Prepared by:



**RTP Environmental Associates, Inc.
304-A West Millbrook Rd.
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Chapter 1. Introduction

1.1 Background

Hyperion Refining LLC (“Hyperion”) has proposed to construct the Hyperion Energy Center, a state-of-the-art center for excellence in the production of clean transportation fuels. The Hyperion Energy Center (the “HEC”) will comprise a greenfield petroleum refinery and an integrated gasification combined cycle (“IGCC”) power plant. The proposed HEC refinery and power plant will rank among the cleanest, most environmentally-friendly in the world. The planned refinery is a 400,000 barrel per day, highly-complex, full-conversion refinery that will produce clean transportation fuels such as ultra-low sulfur gasoline and ultra-low sulfur diesel.

On behalf of Hyperion, RTP Environmental Associates, Inc. (“RTP”) submitted a preconstruction air quality permit application and request for construction approval for the HEC, as required by the Prevention of Significant Deterioration (“PSD”) program and other statutes and regulations, in 2007. In response to that application, Air Quality Preconstruction Permit No. 28.0701-PSD was issued by the South Dakota Department of Environment & Natural Resources (“DENR”) on August 20, 2009.

At the time of issuance of the permit, carbon dioxide (CO₂) and other greenhouse gases (“GHG”) were not pollutants subject to regulation under the Clean Air Act and emissions of those gases were not considered.

Condition 2.1 of the issued permit provides that the permit becomes invalid if Hyperion has not commenced construction by February 20, 2011. This condition also provides that an extension of this deadline may be granted by DENR upon a satisfactory demonstration that an extension is justified. On June 23, 2010, RTP submitted a request for extension of the commence construction deadline to August 20, 2012. In order to demonstrate that the requested extension is justified, RTP’s request letter included an updated air quality impacts analysis and certain other supporting information.

Pursuant to recent U.S. EPA rulemaking, greenhouse gases (“GHG”) may soon become “subject to regulation” under the Clean Air Act and South Dakota’s PSD regulations at ARSD § 74:36:09, with respect to facilities emitting those gases above certain thresholds.^{1, 2, 3} Although the HEC will emit GHG at levels in excess of the applicability thresholds, the PSD permit for the HEC is not directly affected by these new rules because it was issued before January 2, 2011.⁴

¹ GHG is defined at 40 CFR § 86.1818-12(a) as the aggregate group of four gases and two classes of gases: CO₂, nitrous oxide (N₂O), methane (CH₄), sulfur hexafluoride (SF₆), hydrofluorocarbons, and perfluorocarbons.

² See, for example, 75 Fed. Reg. 31514 and 75 Fed. Reg. 53892.

³ RTP and Hyperion are aware of the State of South Dakota’s participation in *Coalition for Responsible Regulation, Inc. v. US EPA* (D.C. Ct. App.) and *Texas v. US EPA* (D.C. Ct. App). Hyperion understands consideration of this submittal in no way affects South Dakota’s participation in that litigation.

⁴ See, 75 Fed. Reg. 31514 at page 31527.

Nonetheless, DENR has requested that RTP provide, as a supplement to its demonstration that the requested extension is justified, a review of Best Available Control Technology (“BACT”) for GHG emissions from the HEC.^{5,6}

1.2 Profile of GHG Emissions from the HEC

The pollutant GHG, for the purposes of the PSD program, will include CO₂, CH₄, N₂O, SF₆, hydrofluorocarbons, and perfluorocarbons.⁷ Emissions of this pollutant are generally expressed in terms of CO₂ equivalent (CO₂e), which takes into account the global warming potential of each component gas.⁸ The CO₂e value is a quantity that describes, for a given mixture and amount of GHG, the amount of CO₂ that would have the same global warming potential.⁹ The HEC is not expected to emit SF₆, hydrofluorocarbons, or perfluorocarbons. The global warming potential of CO₂ is one, so one ton of CO₂ emissions contributes one ton of CO₂e.¹⁰ One ton of methane yields 21 tons CO₂e and one ton of N₂O yields 310 tons of CO₂e.¹¹

The HEC will emit GHG at the rate of approximately 16.9 million tons per year (“tpy”) CO₂e, primarily in the form of CO₂ emissions, as summarized in Table 1-1. These emissions occur from one large vent stream having a high CO₂ concentration and from a number of smaller exhaust streams containing GHG in dilute amounts.

⁵ It is important to note that neither the Clean Air Act nor U.S. EPA’s regulations governing State PSD programs at 40 CFR § 51.166 include any provision establishing PSD permits as invalid in the event the permitted source or modification has not commenced construction within a particular timeframe. This provision is included in South Dakota’s PSD rule with no underlying federal requirement. Accordingly, DENR has broad discretion to interpret what constitutes a satisfactory demonstration that the requested extension is justified.

⁶ DENR has not requested any information pertaining to other PSD program requirements as they would pertain to GHG emissions, such as the requirements for analysis of ambient air quality in the area of the proposed facility and for analysis of the proposed facility’s effects on visibility, soils and vegetation. RTP anticipates that, consistent with U.S. EPA’s finding that “the air pollution of concern is a relatively homogenous atmospheric concentration of greenhouse gases,” these requirements will not apply in any material way to facilities subject to PSD review for emissions of GHG. See, 74 *Fed. Reg.* 66496 at 66522.

⁷ See, for example, 40 CFR § 52.21(b)(49)(i) and 40 CFR § 86.1818-12(a).

⁸ See, for example, 40 CFR § 52.21(b)(49)(ii) and Table A-1 to subpart A of 40 CFR part 98. Note that not all gases in Table A-1 are part of the pollutant GHG for the purposes of PSD regulation.

⁹ See, definition of “carbon dioxide equivalent or CO₂e” at 40 CFR § 98.6.

¹⁰ See, Table A-1 to subpart A of 40 CFR part 98.

¹¹ See, Table A-1 to subpart A of 40 CFR part 98.

Table 1-1. Summary of GHG Emissions from HEC

# of Units	Unit	Emission Rate, Total (tons per year)			
		CO ₂	CH ₄	N ₂ O	CO ₂ e
IGCC					
2	AGR CO ₂ Vent	8,541,956	346.0	0.0	8,549,222
4	Combustion Turbines	3,480,306	64.9	6.5	3,483,683
	Subtotal	12,022,261	410.9	6.5	12,032,904
Process Heaters					
2	CCR Platforming Charge & Inter Heaters	933,701	16.0	1.6	934,532
2	Hydrocracker Fractionator Feed Heater	765,069	13.1	1.3	765,750
1	Oleflex/Butamer/InAlk Heater	341,791	5.8	0.6	342,095
2	Crude Unit Charge Heaters	599,832	10.3	1.0	600,366
	Vacuum Unit Charge Heaters	243,328	4.2	0.4	243,545
2	CCR Platforming 2&3 Inter Heaters	557,957	9.5	1.0	558,453
2	Delayed Coker Unit Charge Heater	275,017	4.7	0.5	275,262
	Delayed Coker Unit Charge Heater	275,017	4.7	0.5	275,262
1	Naphtha Splitter Reboiler Heater	139,772	2.4	0.2	139,897
1	Naphtha Charge Heater	113,176	1.9	0.2	113,277
1	Naphtha Stripper Heater	95,634	1.6	0.2	95,719
1	Distillate Hydrotreater Charge Heater	79,789	1.4	0.1	79,860
1	CCR Reformate Splitter Heater	78,090	1.3	0.1	78,159
2	Hydrocracker Rxn Section Heater	75,828	1.3	0.1	75,895
2	Hydrocracker Rxn Section Heater	75,828	1.3	0.1	75,895
2	Hydrocracker Rxn Section Heater	75,828	1.3	0.1	75,895
2	Hydrocracker Rxn Section Heater	73,564	1.3	0.1	73,630
2	Hydrocracker Rxn Section Heater	73,564	1.3	0.1	73,630
	Subtotal	4,872,786	83.4	8.3	4,877,121
Small Combustion Sources					
6	Emergency Engines	1,609	0.1	0.0	1,615
6	Gasifier Startup Burners	1,415	0.0	0.0	1,417
5	Refinery Flares	2,562	0.0	0.0	2,565
1	IGCC Flare	9,203	0.2	0.0	9,212
2	Tank Farm Thermal Oxidizers	4,278	0.1	0.0	4,282
2	SRU Tail Gas Incinerators	3,120	0.1	0.0	3,123
	Subtotal	22,188	0.4	0.1	22,213
Equipment Leaks		1	3.4	0.0	72
	Total	16,917,236	498	15	16,932,310

1.3 Overview of GHG BACT for the HEC

This report presents a review of BACT for GHG emissions from the HEC. This review shows that the design of the various processes and emissions units comprising the HEC, as well as the HEC as a whole, incorporates the control technologies and techniques representative of BACT. No changes in process design or equipment would result if the HEC were subject to BACT requirements under the South Dakota PSD rule.

1.3.1 GHG BACT Issues Not Specific to the HEC

Determining BACT for GHG emissions from a complex industrial facility such as the HEC has the potential to raise issues that, as a practical matter, have not arisen in performing BACT analyses for conventional pollutants. For example, BACT for conventional pollutants is typically evaluated and expressed in terms of the activity level of the emissions unit undergoing BACT review, in units such as pounds of pollutant per million British thermal unit heat input. Parameters such as the size of the facility, the size of the emissions unit, and energy efficiency historically have not been incorporated into the BACT analysis. The nature of GHG emissions has led to debate regarding whether these parameters should be factored into the analysis.¹²

Pursuant to ARSD § 74:36:09:02, and by reference 40 CFR §§ 52.21(b)(12) and 52.21(j)(2), for a new greenfield facility such as the HEC, BACT applies not to individual emissions units but rather to the major stationary source in its entirety.¹³ Historically, in implementing the BACT requirement for conventional pollutants, DENR and other permitting authorities have typically established BACT either for individual emissions units or for logical groupings of emissions units. In light of the additional parameters potentially considered in establishing BACT for GHG emissions, such as energy-efficient integration of process units at a complex facility such as the HEC, permitting authorities may establish facility-wide BACT emission limits. Of course, as with conventional pollutants, the BACT analysis for GHG emissions for a proposed greenfield facility extends only to emissions occurring from emissions units at the facility; emissions that may occur offsite are not subject to the BACT requirement. Similarly, this analysis does not cover GHG emissions that may occur at other sites or facilities to which GHG-containing gases from the HEC (e.g., CO₂) may be transferred or transported.

1.3.2 GHG BACT Issues Specific to the HEC

Determining the control technologies and techniques that are representative of BACT for GHG emissions from the HEC is an exceptional undertaking because of the size and unparalleled complexity of the facility and because of the unique nature of GHG (especially CO₂) emissions. The proposed HEC represents an unprecedented combination of a highly-complex, full-conversion refinery, with a nominal crude oil charge capacity of 400,000 barrels per day (“BPD”), and an IGCC power plant using as its primary feedstock the petroleum coke produced

¹² See, for example, “Interim Phase I Report of the Climate Change Work Group of the Permits, New Source Review and Toxics Subcommittee, Clean Air Act Advisory Committee,” February 3, 2010, at pp. 6-8; see, also, “Interim Phase II Report of the Climate Change Work Group of the Permits, New Source Review and Toxics Subcommittee, Clean Air Act Advisory Committee,” August 5, 2010, at pp. 7-12.

¹³ § 52.21(j)(2): “A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.”

by the refinery. The HEC would be the seventh largest refinery in the U.S. in terms of crude oil charge capacity and would rank South Dakota as the tenth largest state in terms of operating refining capacity.¹⁴ The power plant would supply the refinery with hydrogen, at a nominal rate of approximately 450 million standard cubic feet per day; electric power, at a nominal rate of 200 megawatts (“MW”); and process steam, at a nominal rate of 2.4 million pounds per hour. The IGCC power plant would be the largest in the world, with a petroleum coke feed rate in excess of 8,000 tons per day. The HEC is a very large facility by any measure, with an estimated capital cost of more than \$10 billion.

For the purposes of determining BACT for GHG emissions, the HEC is unique in two important ways:

- The HEC is designed to be nearly self-sufficient with regard to generation of hydrogen, steam, and electric power needed by the refining process. Most refineries import these commodities in much greater proportion than will the HEC.
- The HEC will not ship off-site carbon-intensive byproducts such as petroleum coke, asphalt, or residual oil, as most refineries do, but rather will use this fraction of the crude oil efficiently on-site for generation of hydrogen, steam, and electric power.

The identification of control technologies and techniques that are representative of BACT for GHG emissions from the HEC are further complicated by the integrated nature of the facility and by the unprecedented requirements for control of conventional air pollutants. For example:

- On-site generation of hydrogen, steam, and electricity results in greater on-site emissions of CO₂. Alternatives to this fundamental aspect of the facility’s design would simply shift the CO₂ emissions off-site. Because the environmental impact of CO₂ emissions is unrelated to the location at which those emissions are generated, no quantifiable environmental benefit would result from those alternatives.
- Use of an on-site IGCC power plant fed primarily with carbon-intensive petroleum coke to generate hydrogen, steam, and electricity, results in greater on-site emissions of CO₂. Alternatives to this fundamental aspect of the facility’s design would simply shift the CO₂ emissions off-site. Because the environmental impact of CO₂ emissions is unrelated to the location at which those emissions are generated, no quantifiable environmental benefit would result from those alternatives.
- Use of an on-site air separation plant to produce oxygen for the gasification process and for the fully oxygen-blown sulfur recovery plant increases the refinery’s electrical demand, thereby increasing the size of the IGCC power plant and its CO₂ emissions. Alternatives to this fundamental aspect of the facility’s design would result in increased CO₂ emissions from transportation and would shift the CO₂ emissions off-site. This design aspect renders meaningless any comparison of CO₂ emissions from the power plant at the HEC with power plants at other refineries.
- The use of heavy Canadian crude, refining of which is energy intensive, will result in greater on-site emissions of CO₂. Alternatives to this fundamental aspect of the facility’s

¹⁴ U.S. Energy Information Administration, *Refinery Capacity Report*, June 25, 2010. Accessed September 10, 2010, at www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html.

design would result in the refinery being sited outside South Dakota and in the Canadian crude being refined at a different refinery, less efficiently and probably outside the United States. Because the environmental impact of CO₂ emissions is unrelated to the location at which those emissions are generated, no quantifiable environmental benefit would result from those alternatives.

- The use of the energy-intensive delayed coking process to maximize the production of clean transportation fuels results in greater on-site emissions of CO₂ per barrel of crude oil processed. Alternatives to this fundamental aspect of the facility's design would result in either a greater crude oil charge capacity to produce the same amount of transportation fuel, with greater CO₂ emissions from other on-site process units, or production of transportation fuels at other refineries, resulting in a shift of the CO₂ emissions off-site.
- The sizing of the process heaters in the various process units is based on energy-efficient integration of those units, meaning that the heat in various intermediate and product streams is transferred to other process streams for beneficial use, and on energy-efficient use of steam. This integrated design renders meaningless any comparison of the CO₂ emissions from a particular refining process at the HEC with comparable units at other refineries because there are no other refineries of similar size and integration.
- The use of a robust flare gas recovery system with significant compressor capacity increases the refinery's electrical demand, thereby increasing the size of the IGCC power plant and its CO₂ emissions. This design aspect, which is required as BACT for conventional air pollutants and which will reduce CH₄ emissions, renders meaningless any comparison of CO₂ emissions from the power plant at the HEC with power plants at other refineries because there are no other refineries of similar size and design.
- The use of advanced amine treating for cleanup of refinery fuel gas increases the refinery's steam demand, thereby increasing the size of the IGCC power plant and its CO₂ emissions. This design aspect, which is required as BACT for conventional air pollutants, renders meaningless any comparison of CO₂ emissions from the power plant at the HEC with power plants at other refineries because there are no other refineries of similar size and design.
- The use of selective catalytic reduction systems and oxidation catalysts, which are required as BACT for conventional air pollutants, increases the facility's GHG emissions. These controls also increase the facility's electrical demand, thereby increasing the size of the IGCC power plant and its CO₂ emissions. This design aspect renders meaningless any comparison of CO₂ emissions from the HEC with other refineries.
- The use of closed-vent systems routed to oxidizers for 98 storage vessels, which is required as BACT for VOC emissions, will increase the facility's CO₂ emissions both directly (due to emissions from the oxidizers) and indirectly (due to increases in the refinery's electrical demand). This design aspect renders meaningless any comparison of CO₂ emissions from the HEC with other refineries.
- The use of the Rectisol[®] wash process for cleanup of syngas in the IGCC power plant, which is required as BACT for conventional air pollutants, increases the facility's electrical demand, thereby increasing the size of the IGCC power plant and its CO₂ emissions. This design aspect renders meaningless any comparison of CO₂ emissions from the power plant at the HEC with power plants at other refineries.

As a result, GHG mitigation techniques that may reduce emissions of GHG from the HEC by shifting them elsewhere, or by fundamentally redefining the design of the facility, were not considered. Additionally, comparisons of GHG emission rates from the HEC IGCC power plant or refinery to other IGCC power plants and refineries were not made because, for the reasons outlined above, there are no comparable facilities.

Chapter 2. GHG BACT for IGCC CO₂ Vent

The IGCC CO₂ vent gas is a high purity CO₂ stream produced by the Rectisol[®] wash process for acid gas removal at the IGCC power plant. This stream will contain trace quantities of CH₄, as well as trace quantities of non-GHG pollutants such as CO and H₂S. This stream will have two dispositions: 1) venting to the atmosphere; and 2) compression for off-site transport, such as would be required for sequestration or productive end use (*e.g.*, oil-field injection for enhanced oil recovery). When option two becomes available, the vent stream will be dried, compressed and delivered to site battery limits for offsite use, sequestration, or disposal.

2.1 BACT Baseline.

There are no applicable NSPS or NESHAP rules that would establish a baseline GHG emission rate for the IGCC CO₂ vent gas stream.

2.2 Step 1 – Identify GHG Control Options

The identified control options for CH₄ emissions from the Rectisol[®] wash process are proper equipment design and operation, thermal oxidation, and catalytic oxidation.

The only identified strategy for mitigating CO₂ emissions from the acid gas removal process at the HEC IGCC is carbon capture and storage (“CCS,” also referred to as “carbon capture and sequestration”). As indicated by the name, this technique involves capturing CO₂, transporting it as necessary, and permanently storing it instead of releasing it into the atmosphere. The process involves three main steps:

- Capturing CO₂ at its source by separating it from other gases produced by an industrial process;
- Transporting the captured CO₂ to a suitable storage location (typically in compressed form); and
- Storing the CO₂ away from the atmosphere for a long period of time, for instance in underground geological formations, in the deep ocean, or within certain mineral formations.

It should be noted that one other identified option for achieving the hydrogen, steam, and electric power production that will be achieved by the IGCC power plant at the HEC is the use of natural gas as feed to a hydrogen production process and as fuel for a combined-cycle power plant. The petroleum coke produced at the HEC would be sold as a product for off-site use, such as in a pulverized coal-fired power plant emitting the carbon as CO₂ somewhere else. This option is fundamentally inconsistent with the design of the HEC, which is a petroleum refinery that

maximizes the utilization of petroleum and petroleum intermediates. Because the use of natural gas in this manner would fundamentally redefine the design of the HEC, it is not considered further in this analysis.

Isolation of relatively pure CO₂ is inherent to the IGCC acid gas removal process, the Rectisol[®] wash process, for effective removal of the CO₂ from the syngas stream. Permanent carbon storage is possible only in a very limited number of sites, and the site of the HEC is not a suitable storage location. Accordingly, the captured CO₂ must be transported to a suitable storage site in order to achieve any environmental benefit. Pipelines are the most common method for transporting large quantities of CO₂ over long distances.

The oldest long-distance CO₂ pipeline in the United States is the 140 mile Canyon Reef Carriers Pipeline (in Texas), which began service in 1972 for Enhanced Oil Recovery (“EOR”) in regional oil fields. Other large CO₂ pipelines have been constructed since then, mostly in the mid-continent, Western United States, to transport CO₂ for EOR. These pipelines carry CO₂ from naturally-occurring underground reservoirs, natural gas processing facilities, ammonia manufacturing plants, and a large coal gasification project to oil fields. Altogether, approximately 3,600 miles of CO₂ pipeline operate today in the United States.

Pipeline transportation of CO₂ is typically accomplished with CO₂ that is compressed to its supercritical state, involving pressures of 1200 to 2000 pounds per square inch. This compression requires high levels of energy consumption. In addition, water must be eliminated from CO₂ pipeline systems, as the presence of water results in formation of carbonic acid, which is extremely corrosive to carbon steel pipe. The primary compressor stations are located at the CO₂ source and where the CO₂ is injected, and booster compressors located as needed along the pipeline. In overall construction, CO₂ pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. All of these technical issues can be addressed through modern pipeline construction and maintenance practices.

There are several options being explored and employed for permanent storage of CO₂. These options include gaseous storage in various deep geological formations (including saline formations, exhausted oil and gas fields, and unmineable coal seams), liquid storage in the ocean, solid storage by reaction of CO₂ with metal oxides to produce stable carbonates, and terrestrial sequestration.

2.3 Step 2 – Eliminate Technically Infeasible Control Options

2.3.1 Proper Equipment Design and Operation

Proper equipment design and operation for minimization of CH₄ emissions from the CO₂ vent is technically feasible and is inherent in the design of the HEC IGCC power plant. The expected CH₄ concentration is 110 parts per million by volume (“ppmv”), which will result in annual CH₄ emissions of 79 pounds per hour and 346 tons per year, or approximately 7,300 tons CO₂e per year.

2.3.2 Thermal Oxidation and Catalytic Oxidation

Although it may be possible to apply thermal oxidation or catalytic oxidation for the purpose of oxidizing a portion of CH₄ emissions in the CO₂ vent stream, these are not technically feasible options for reducing GHG emissions from the acid gas removal process at the HEC.

The CO₂ vent stream is characterized by negligible oxygen concentration, low CH₄ concentration (approximately 110 ppmv), high volumetric flow rate (approximately 300,000 cubic feet per minute), and low temperature (approximately 100 °F). In order to use either thermal oxidation or catalytic oxidation, a large amount of auxiliary air would have to be added in order to provide oxygen and a large amount of auxiliary fuel would have to be burned in order to increase the temperature of the resulting gas stream. The precise amount of auxiliary combustion air has not been determined, but a minimum oxygen concentration of 20 percent by volume in the exhaust gas stream is normally required. Assuming for discussion purposes that 15 percent oxygen by volume would suffice for this application, approximately 800,000 cubic feet of auxiliary air per hour would have to be added, yielding an exhaust gas stream with a volumetric flow rate of approximately 1,000,000 cubic feet per minute and a CH₄ concentration of approximately 30 ppmv. Assuming 70 percent energy recovery, the amount of natural gas required as auxiliary fuel to achieve the required oxidation temperature would be approximately 320 MMBtu/hr for a catalytic oxidation system and approximately 850 MMBtu/hr for a thermal oxidation system. Conservatively assuming that 100 percent of the CH₄ in the exhaust gas stream and in the auxiliary fuel is fully oxidized to CO₂, the resulting CO₂ emissions are approximately 170,000 tons CO₂e per year for a catalytic oxidation system and 440,000 tons CO₂e per year for a thermal oxidation system. Because use of these systems to oxidize CH₄ would increase rather than decrease GHG emissions both on a mass basis and on a CO₂e basis, these are not technically feasible control options.

2.3.3 Carbon Capture and Storage

Capture, compression, and transportation of CO₂ from the acid gas removal process at the HEC are technically feasible. Of the CO₂ storage options listed in Section 2.2, only a limited number are technically feasible, as discussed below.

2.3.3.1 Geologic Formations

The geologic formations considered appropriate for CO₂ storage are layers of porous rock deep underground that are “capped” by a layer or multiple layers of non-porous rock above them. In this application a well is drilled down into the porous rock and pressurized CO₂ is injected into it. Under high pressure, CO₂ turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO₂ tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO₂ and prevent further upward migration.

There are other mechanisms for CO₂ trapping as well: CO₂ molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of porous rock. The degree to which a specific underground formation is amenable to CO₂ storage can be difficult to determine. Research is being performed today which is aimed at developing the ability to characterize a formation before CO₂ injection in order to predict its CO₂ storage capacity. Another area of research is the development of CO₂ injection techniques that achieve broad

dispersion of CO₂ throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock.

Several of the major unresolved issues with respect to CO₂ sequestration pertain to the legal framework for closing and remediating sequestration sites, including liability for accidental releases from these sites. The Federal government has recently proposed regulations outlining requirements that owners or operators must demonstrate and maintain with respect to financial responsibility. These regulations are proposed under the authority of the Safe Drinking Water Act and do not address ambient air impacts.¹⁵ Until the financial responsibility issues are defined and codified by the Federal government, companies and most likely states will not undertake commercial geologic CO₂ sequestration activities beyond those states that already have regulations for EOR.

There are several types of geologic formations in which CO₂ can be stored, and each has different opportunities and challenges as briefly described below:

2.3.3.1.1 *Depleted oil and gas reservoirs*

These are formations that held crude oil and natural gas at some time. In general, they are characterized by a layer of porous rock with a layer of non-porous rock which forms a dome. This dome offers great potential to trap CO₂ and makes these formations excellent sequestration opportunities.

As a value-added benefit, CO₂ injected into a depleting oil reservoir can enable recovery of additional oil and gas. When injected into a depleted oil bearing formation, the CO₂ dissolves in the trapped oil and reduces its viscosity. This improves the ability of oil to move through the pores in the rock and flow with a pressure differential toward a recovery well. A CO₂ flood typically enables recovery of an additional 10 to 15 percent of the original oil in place. Enhanced oil recovery and enhanced gas recovery are commercial processes and in demand recently with high commodity prices. It is estimated that 50 to 90 billion metric tons of sequestration potential exists in mature oil and gas reservoirs identified by the Regional Carbon Sequestration Partnerships (RCSPs). Formed by the U.S. Department of Energy in 2003, the seven Partnerships span 40 states, three Indian nations, and four Canadian provinces.¹⁶ There are no known oil or gas reservoirs providing CO₂ sequestration opportunities within the immediate vicinity of the HEC, but there are oil fields in Otsego County, in southwestern Nebraska, approximately 300 miles from HEC, and in southwestern North Dakota, approximately 400 miles from HEC, that have significant EOR opportunity.¹⁷ These oil fields provide a sequestration opportunity that is considered technically feasible for the HEC, although not necessarily legally feasible.

¹⁵ "Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells." 73 *Fed. Reg.* 43492. July 25, 2008.

¹⁶ "Carbon Sequestration Atlas of the United States and Canada", page 13 of: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/National%20Perspectives.pdf

¹⁷ *Ibid.* Page 69.

2.3.3.1.2 *Unmineable coal seams*

Unmineable coal seams are those that are too deep or too thin to be mined economically. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coal beds to recover this coal bed methane (“CBM”). Initial CBM recovery methods, dewatering and depressurization, leave an appreciable amount of CBM in the reservoir. Additional CBM recovery can be achieved by sweeping the coal bed with nitrogen or CO₂, which preferentially adsorbs onto the surface of the coal, releasing the methane. Two or three molecules of CO₂ are adsorbed for each molecule of methane released, thereby providing an excellent storage sink for CO₂. Like depleting oil reservoirs, unmineable coal beds are a good early opportunity for CO₂ storage.

One potential barrier to injecting CO₂ into unmineable coal seams is swelling. When coal adsorbs CO₂, it swells in volume. In an underground formation swelling can cause a sharp drop in permeability, which not only restricts the flow of CO₂ into the formation but also impedes the recovery of displaced CBM. Two possible solutions to this challenge include angled drilling techniques and fracturing.

It is estimated that 150 to 200 billion metric tons of CO₂ sequestration potential exists in unmineable coal seams identified by the RCSPs.¹⁸ Such seams are known to exist in the vicinity of the HEC in southwestern North Dakota, approximately 400 miles from HEC, and central Iowa, approximately 200 miles from HEC.¹⁹ Although CO₂ sequestration in unmineable coal seams may be technically feasible, it is much less developed and proven relative to EOR. As such, CO₂ sequestration in unmineable coal seams will not be considered further in this analysis based on the limited development and because the coal seams are not significantly closer to the HEC than are the EOR sites.

2.3.3.1.3 *Saline formations*

Saline formations are layers of porous rock that are saturated with brine. They are much more commonplace than coal seams or oil and gas bearing rock, and represent an enormous potential for CO₂ storage capacity. The RCSPs estimate a range of 3,300 to 12,000 billion metric tons of sequestration potential in saline formations.²⁰ However, much less is known about saline formations than is known about crude oil reservoirs and coal seams, and there is a greater amount of uncertainty associated with their ability to store CO₂. Saline formations contain minerals that could react with injected CO₂ to form solid carbonates. The carbonate reactions have the potential to be both a positive and a negative. They can increase permanence but they also may plug up the formation in the immediate vicinity of an injection well. Additional research is required to better understand these potential obstacles and how best to overcome them.²¹ Such saline formations are known to exist in the vicinity of the HEC in northwestern South Dakota, approximately 250 miles from HEC, and southwestern Nebraska, approximately 300 miles from HEC.²² Although CO₂ sequestration in saline formations may be technically feasible, it is much less developed and proven in comparison to EOR. As such, CO₂

¹⁸ Ibid. page 14.

¹⁹ Ibid. page 63.

²⁰ Ibid. page 20.

²¹ Ibid, page 15

²² Ibid. page 63.

sequestration in saline formations will not be considered further in this analysis based on the limited development and because the saline formation are not any closer to HEC as the EOR sites.

2.3.3.1.4 Basalt formations

Basalts are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO₂ to a solid mineral form, thus permanently isolating it from the atmosphere. Current research is focused on enhancing and utilizing the mineralization reactions and increasing CO₂ flow within a basalt formation. Although oil and gas-rich organic shale and basalt research is in its infancy, these formations may, in the future, prove to be optimal storage sites for sequestering CO₂ emissions. This CO₂ sequestration technique is considered technically infeasible for the HEC at this time due to its limited development, and it will not be considered further in this analysis.

2.3.3.2 Terrestrial Ecosystems

Terrestrial sequestration is the enhancement of CO₂ uptake by plants that grow on land and in freshwater and, importantly, the enhancement of carbon storage in soils where it may remain more permanently stored. Terrestrial sequestration provides an opportunity for low-cost CO₂ emissions offsets. Early efforts include tree-plantings, no-till farming, and forest preservation. To date, there are no applications that would be large enough to handle 8.5 million tons per year of CO₂.

Carbon can be sequestered in terrestrial ecosystems by:²³

1. Increasing the amount of aboveground biomass in an ecosystem. Biomass is matter originally created by living organisms such as trees, leaves, and bacteria. The ultimate origin of the carbon in virtually all biomass is atmospheric CO₂, so storing biomass is storing atmospheric carbon. Dry biomass is roughly 50 percent carbon by weight. Forest ecosystems contain more living biomass than any other ecosystem so converting grasslands or croplands to forest is one way of sequestering carbon.
2. Increasing the amount of carbon held in soils. Soil carbon originates primarily from plant and fungal material which is then processed by other fungi and bacteria. Soil carbon can also originate from charcoal or char created when an ecosystem burns. Many factors control how much carbon goes into soil and how long the carbon stays in the soil.

Both approaches can be addressed simultaneously on the same piece of land. In general croplands store less carbon than grasslands which store less carbon than forests. Grasslands are particularly good at storing carbon in soils because they often have extensive and deep roots. Soil carbon is less vulnerable to rapid loss than aboveground biomass which can be quickly lost to the atmosphere in a fire.

Sequestration of carbon in terrestrial ecosystems is a low-cost option that may be available in the near-term to mitigate increasing atmospheric CO₂ concentrations, while providing additional

²³ "Carbon Sequestration in Terrestrial Ecosystems: A Status Report on R&D Progress", Gary K. Jacobs, et. al., Oak Ridge National Laboratory, Oak Ridge, TN. August 2000.

benefits. Storing carbon in terrestrial ecosystems can be achieved through maintenance of standing aboveground biomass, utilization of aboveground biomass in long-lived products, or protection of carbon (organic and inorganic) compounds present in soils. There are potential co-benefits from efforts to sequester carbon in terrestrial ecosystems. For example, long-lived valuable products (wood) are produced, erosion would be reduced, soil productivity could be improved through increased capacity to retain water and nutrients, and marginal lands could be improved and riparian ecosystems restored. Another unique feature of the terrestrial sequestration option is that it is the only option that is “reversible” should it become desirable and permissible. For example, forests that are created are thus investments which could be harvested should CO₂ emissions be reduced in other ways to acceptable levels 50-100 years from now.

However, due to the undemonstrated cost and effectiveness of terrestrial ecosystem sequestration options for storing 8.5 million tons per year of CO₂ over the life of the HEC, this sequestration option is considered technically infeasible and will not be further evaluated as BACT.

2.4 Step 3 – Characterize Control Effectiveness of Technically Feasible Control Options

The only technically feasible strategy for mitigating CO₂ emissions from the acid gas removal process at the HEC is CCS. For the purposes of this analysis, depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 100 percent effective and to result in a CO₂ emission reduction of approximately 8.5 million tons per year.

2.5 Step 4 – Evaluate More Effective Control Options

The exhaust stream from the CO₂ vent gas stream at the HEC IGCC power plant will be suitable for transporting by pipeline, with a purity of approximately 98 percent CO₂, but would need to be dried and boosted from a pressure of approximately 900 pounds per square inch at the acid gas removal process exit to 2000 pounds per square inch at the pipeline. These requirements would increase the electrical load on the IGCC power plant by 267 megawatts (“MW”).²⁴ This additional electrical load, even if produced at the state-of-the-art IGCC power plant at the HEC, would significantly increase fuel and energy use and would increase air emissions by approximately 175 tons of PM-2.5, 86 tons of NO_x, 50 tons of SO₂, 53 tons of CO, and 13 tons of VOC per year. The estimated capital costs for equipment needed for compression, pipeline transportation, and injection/storage are approximately \$650 million. The levelized annual cost, including operating cost, is estimated to be approximately \$300 million per year. The resulting avoided cost of CO₂ CCS is approximately \$43 per ton of CO₂ sequestered. (See Appendix A for details regarding these impacts.)

²⁴ Compressing captured CO₂ to pipeline pressure represents a large parasitic load.
http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html.

It has been assumed for this analysis that the recovered CO₂ from the acid gas removal process at the HEC could be used to provide value in an EOR opportunity. The IPCC special report on CCS estimated a credit of \$9 to \$15 per ton of CO₂ for EOR but does not include long term monitoring and maintenance costs, and costs associated with legal issues.²⁵ Assuming the cost benefit of EOR offsets long term monitoring and maintenance costs, the net levelized annual cost is approximately \$43 per ton of CO₂.

In RTP's experience, there is no precedent for determining the costs that are reasonable for CO₂ emission reduction in the context of a BACT analysis. In the absence of such precedent, market values of these reductions have been used for comparison. Currently, the market price of carbon credits traded on the Chicago Climate Exchange is less than \$1 per short ton; the current market price on the European Climate Exchange, where the market is more established, is approximately \$12 per short ton. Based on these values, the cost of CCS for the acid gas removal process at the HEC is not reasonable. In conjunction with the significant, adverse energy and environmental impacts of CCS, this control option does not represent BACT.

2.6 Step 5 - Establish BACT

No control option more effective than the inherent design has been identified as BACT for GHG emissions from the acid gas removal process at the HEC IGCC power plant. RTP proposes that a GHG emission limit of 58.6 tons CO₂e per thousand barrels crude charge, on an annual average basis, be established as BACT for the acid gas removal process at the HEC IGCC power plant. This proposed limit reflects the potential GHG emissions of 8.54 million tons CO₂e per year, as reflected in Table 1-1 herein, and the nominal refinery crude charge capacity of 400,000 barrels per day.

²⁵ *IPCC Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change. 2005. Page 345.

Chapter 3. GHG BACT for Process Heaters

The HEC petroleum refinery will include thirty process heaters burning refinery fuel gas. These process heaters will emit three GHG's: CH₄, CO₂, and N₂O.

One of the useful byproducts produced by the petroleum refining process is refinery fuel gas. This gas is generally similar to natural gas but contains less methane and more hydrogen and ethane than does natural gas. The refinery fuel gas produced at the HEC will be entirely consumed by the refinery process units as a fuel source.

Methane is emitted from combustion devices burning natural gas or refinery fuel gas as a result of incomplete combustion. Because fuel costs represent one of the highest operating costs for a petroleum refinery, fuel combustion devices are designed to achieve the highest combustion efficiencies practicable. Although CH₄ emissions can be reduced by operating the combustion devices at higher flame temperatures, higher excess oxygen levels, and longer furnace residence time, these techniques for reducing CH₄ emissions can increase NO_x emissions. Consequently, achieving low CH₄ and NO_x emission rates is a balancing act in the combustor design and operation.

Carbon dioxide will be emitted from process heaters because it is a combustion product of any carbon-containing fuel. All fossil fuels contain significant amounts of carbon. In the combustion of a fossil fuel, the fuel carbon is oxidized into carbon monoxide (CO) and CO₂. Full oxidation of fuel carbon to CO₂ is desirable because CO has long been a regulated pollutant with established adverse health impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO₂ in the atmosphere. Unlike fossil fuel-fired electric power plants, which emit CO₂ from one stack or a small number of stacks located in proximity to one another, petroleum refinery CO₂ emissions are generated and emitted from sources and stacks scattered throughout the facility. Thus, as discussed in detail below, full capture of CO₂ emissions from the many process heater exhaust stacks located throughout the HEC is inefficient, challenging, and costly relative to a fossil fuel-fired electric power plant. Additionally, the CO₂ concentrations of the flue gases are quite low (~5 percent) because refinery fuel gas is a low carbon fuel as is natural gas.

Nitrous oxide will be emitted from the process heaters in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process and, for the heaters equipped with selective catalytic reduction ("SCR"), N₂O is formed through catalytic reduction reactions.²⁶

²⁶ See, for example, EPA Air Pollution Control Cost Manual, 6th Ed. EPA-452/B-02-001. Section 4.2, Chapter 2, "Selective Catalytic Reduction." U.S. EPA. October 2000.

3.1 BACT Baseline

There are no applicable NSPS or NESHAP rules that would establish a baseline GHG emission rate for the process heaters at the HEC petroleum refinery.

3.2 Step 1 – Identify Control Options

The potentially available control technologies for CH₄ emissions from process heaters fired with refinery fuel gas are the same as those discussed, with respect to CO and VOC emissions from process heaters, in Sections 4.2.3 and 4.2.4 of the December 2007 permit application for the HEC. These are good combustion practices and the use of oxidation catalyst. Both of these technologies, as discussed below, are designed to oxidize CH₄ and other carbon-containing compounds in fuel to form CO₂, which also is a GHG. Fully combusting one ton of CH₄ forms 2.74 tons of CO₂, which means that on a mass basis both of the identified control options for CH₄ emissions from process heaters fired with refinery fuel gas actually would result in increases in GHG emissions. However, as discussed in Section 1.2 herein, the global warming potential of CH₄ is 21 times higher than that of CO₂, so the identified control options would result in decreases in GHG emissions when expressed on a CO₂e basis. For the purposes of this BACT analysis, RTP has assumed that reductions of GHG emissions expressed on a CO₂e basis are the primary objectives, so the identified control options are considered as providing beneficial environmental impacts through oxidation of CH₄ and other carbon-containing compounds in fuel to form CO₂.

The potentially available control technologies for CO₂ emissions from process heaters fired with refinery fuel gas are aggressively energy-efficient design in order to minimize the amount of fuel combusted; the use of low-carbon fuels in order to minimize the formation of CO₂ from fuel combustion; and CCS, as discussed in Section 2.2 herein.

The only identified control technologies for the control of N₂O from process heaters fired with refinery fuel gas are aggressively energy-efficient design, in order to minimize the amount of fuel combusted, and elimination of SCR.

3.2.1 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone; and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CH₄ emissions. Combustion efficiency is related to the three “T’s” of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed into the process heater to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through process heater/burner design and operation.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels will result in high CH₄ levels and can also affect NO_x formation. Increased excess air levels will reduce the emissions of CH₄ up to the point that so much excess air is introduced that the overall combustion temperatures begin to drop significantly. If combustion temperatures drop significantly, then process heater efficiency and process fluid temperatures are also negatively affected. Low excess air levels lower combustion temperatures and do not allow sufficient oxygen to allow efficient combustion of CH₄ but does reduce the formation of thermal NO_x. Process heaters operate within a narrow range of excess air levels due to the interrelationships between oxygen levels, combustion efficiency, and formation of NO_x, and products of incomplete combustion such as CH₄.

3.2.2 Oxidation Catalyst

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH₄ emissions. This technology utilizes excess air present in the combustion exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Reactants are introduced into a catalytic bed, with the optimum temperature range for these systems being approximately 850 °F to 1,100 °F. No chemical reagent addition is required.

3.2.3 Low-Carbon Fuel

Table 3-1 presents the amount of CO₂ formed when combusting fossil fuels, including the fuels that will be used at the HEC.

Table 3-1. CO₂ Emission Factors	
<u>Fuel</u>	<u>Pounds CO₂ per Million Btu</u>
Petroleum Coke	225 *
Coal	210 *
Residual Oil	174 *
Diesel	161 *
HEC Refinery Fuel Gas	≈ 129
Natural Gas	117 *
PSA Tail Gas	≈ 100
HEC Syngas	≈ 50
* Energy Information Administration at http://www.eia.doe.gov/oiaf/1605/coefficients.html	

As shown in Table 3-1, the use of gaseous fuels, such as natural gas and refinery fuel gas, reduces the production of CO₂ during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils).

3.2.4 Energy Efficient Design

A highly efficient refinery requires less fuel for process heat, which directly impacts the amount of GHG produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce GHG formation. Elements of a highly energy-efficient design for a greenfield petroleum refinery such as the HEC include the following.

3.2.4.1 Combustion Air Preheat

Air preheat is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber or furnace. Preheating the combustion air reduces the amount of fuel required in the furnace because the combustion air does not have to be heated all the way from ambient temperature to the fuel combustion temperature by combusting fuel. The achievable reduction in fuel usage and GHG emissions is typically 10 to 15 percent. This heat recovery approach historically has been used only on large process heaters at petroleum refineries. However, as energy costs have increased, the boiler and heater size for which it is economically practical has steadily decreased. To equip a process heater with air preheat requires the addition of a draft fan and heat exchanger incurring capital, operating, and maintenance costs; for heaters of sufficient size, these costs can be offset by the fuel savings. Although combustion air preheat reduces the amount of GHG emitted, it increases emissions of NO_x because preheating the combustion air increases combustion temperature. The HEC will employ air preheat on 9 of 30 process heaters representing 70 percent of the facility-wide heat input to process heaters. This is equivalent to approximately 0.15 million tons per year of CO₂ that would be emitted firing additional natural gas or refinery fuel gas to make up the heat lost in the heater flue gas. Since selective catalytic reduction will be used for these large heaters, the potential increase in NO_x emissions from the air preheat will be eliminated.

3.2.4.2 Use of Process Heat to Generate Steam

One method that petroleum refiners use to improve energy efficiency is to cool hot process streams by generating steam. This is done by passing the hot process stream through a heat exchanger to transfer the heat to boiler feed water. The HEC will generate both high pressure (600 psig steam) and low pressure steam (50 psig steam) using this approach. Approximately 15 percent of the refinery's steam demand will be generated using process heat recovery. This is equivalent to approximately 0.3 million tons per year of CO₂e that would be emitted if natural gas or refinery fuel gas was used to generate this steam instead.

3.2.4.3 Process Integration and Heat Recovery

Traditionally, petroleum refinery process units, such as crude distillation units, send the various product streams directly to intermediate storage tanks after the product has been cooled using cooling water. Then the downstream processing unit, for example a Diesel Hydrotreating unit, is fed by pumping the cooled diesel stream from the intermediate storage tank. This requires the diesel feed stream to be heated up from its cooled storage temperature to its processing

temperature. Energy is saved if the hot diesel stream from the crude unit is pumped directly to the Hydrotreating unit. The HEC will make use of the most advanced design approaches to integrate the process units and to maximize energy efficiency.

3.2.4.4 Continuous Excess Air Monitoring and Control

Excessive amounts of combustion air used in process heaters results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. This requires the installation of an oxygen monitor in the heater stack and damper controls on the combustion air dampers. Additionally, avoiding high excess air levels, while maintaining good combustion, reduces not only GHG emissions but also NO_x emissions. All of the HEC process heaters will be equipped with oxygen monitors as part of the continuous emission monitoring system.

3.2.4.5 Cogeneration as a CO₂ Reduction Technique

Cogeneration is the use of a heat source to simultaneously generate both electricity and useful heat (*e.g.*, steam). A typical configuration is the use of combustion turbines to generate electricity, with the waste heat used to generate steam in a heat recovery steam generator (“HRSG”). The HEC will use the cogenerated steam as heat at various refinery process units. The reduction in GHG emissions from employing cogeneration comes from the reduced fuel use needed to make steam for the refinery process units; thus, the amount of GHG reduction is dependent upon the type of electric utility power generation displaced. Where coal-based generation is displaced, GHG emissions reductions of 30 percent or more are achievable. The HEC will make use of an IGCC power plant design that will provide for cogeneration of steam and electricity using a low value fuel, petroleum coke generated at the refinery. This approach is more energy efficient than purchasing electricity from an electric utility and generating steam by burning coke, residual oil, or natural gas.

Note, the efficiencies above are not additive when layering technology options (*e.g.*, addition of air preheat and continuous monitoring of excess air), some options may preclude the use of other options in certain equipment, and some options are not practical for application to small combustion sources.

3.2.5 Carbon Capture and Storage

As discussed in Chapter 2 herein, CCS can be used to reduce atmospheric emissions of CO₂ after formation. However, unlike the exhaust stream associated with the acid gas removal process, the inherent design of the process heaters at the HEC produce a number of dilute CO₂ streams, such that separation of CO₂ from other exhaust gas constituents (*i.e.*, “capture”) is much more difficult and costly.

The CO₂ emissions from the combustion sources at the HEC can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion

approach, oxygen instead of air is used to combust the fuel and a concentrated CO₂ exhaust gas is generated.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO₂ from the combustion exhaust gases. Because the air used for combustion contains 79 percent nitrogen and because refinery fuel gas is a low-carbon fuel, the CO₂ concentration in the exhaust gases is approximately 5 percent or less.

In addition to these capture techniques, in order to provide effective reduction of CO₂ emissions, methods of compression, transport, and storage also would be required. Available methods are discussed in Chapter 2 herein.

3.2.6 Eliminating SCR

Use of SCR is expected to contribute to N₂O formation in the twenty process heaters for which this control technology is required in order to achieve the BACT emission limits for NO_x. Eliminating this control technology would be expected to result in lower N₂O emission rates.

3.3 Step 2 – Eliminate Technically Infeasible Control Options

Four of the six categories of control options identified in Section 3.2 are technically feasible for application to the process heaters at the HEC petroleum refinery for control of GHG emissions.

3.3.1 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas, as described in Section 3.2.1 herein, are technically feasible and are inherent in the design of the HEC petroleum refinery.

3.3.2 Oxidation Catalyst

For the same reasons discussed in Section 4.2.3.3 of the initial permit application for the HEC, oxidation catalyst is not a technically feasible option for control of GHG emissions from process heaters at the HEC petroleum refinery.

The typical oxidation catalyst for CO-containing exhaust gases is rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 to 1250 °F, with the optimal range being 850 to 1,100 °F. Below approximately 600 °F, a greater catalyst volume would be required to achieve the same reduction. To achieve this temperature range in process heaters fired with refinery fuel gas, the catalyst would need to be installed in the heater upstream of any waste heat recovery or air preheat equipment.

Installation of oxidation catalyst in flue gas containing more than trace levels of SO₂ will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as

increasing the conversion of SO₂ to SO₃. The increased conversion of SO₂ to SO₃ will increase condensible particulate matter emissions and increase flue gas system corrosion rates. In addition, for heaters equipped with SCR for NO_x control, the presence of SO₃ in the exhaust gas will result in plugging or deactivation of the SCR catalyst. For these reasons, catalytic oxidation of CH₄ is not considered technically feasible for the refinery fuel gas fired process heaters.

3.3.3 Low-Carbon Fuels

The process heaters at the HEC petroleum refinery will be fueled with refinery fuel gas, which, as shown in Table 3-1, is a low-carbon fuel. The only identified fuels with lower CO₂ formation rates are syngas, pressure swing adsorption (“PSA”) tail gas, and natural gas. Production of additional syngas or PSA tail gas at the HEC petroleum refinery would lead to overall increases in GHG emissions from the refinery, so these fuels do not represent options for reducing GHG emissions. Natural gas is commercially available and would yield slightly reduced CO₂ emission rates from the process heaters, but displacing refinery fuel gas from use as fuel in process heaters would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring. Thus, there are no control options involving the use of low-carbon fuels in process heaters that represent technically feasible options for reducing GHG emissions relative to the proposed use of refinery fuel gas.

3.3.4 Energy Efficiency

Each of the strategies for energy-efficient design identified in Section 3.2.4 herein is technically feasible for application to the HEC petroleum refinery and is inherent in the design of the facility.

3.3.5 Carbon Capture and Storage

As discussed in Chapter 2 herein, there are available and technically feasible methods for compression, transport, and storage of concentrated CO₂ streams. Options for capturing CO₂ emissions from process heaters fired with refinery fuel gas, which would be required as an element of CCS as a GHG emission control option, are discussed below.

3.3.5.1 Pre-Combustion CO₂ Capture

The pre-combustion technique for CO₂ separation involves substituting pure oxygen for air in the combustion process. This “oxyfuel” process has not yet been tested or demonstrated in a large-scale facility such as the process heaters at the HEC petroleum refinery.²⁷ Accordingly, CCS involving pre-combustion CO₂ separation and capture is not technically feasible for the process heaters at the HEC petroleum refinery.

3.3.5.2 Post-Combustion CO₂ Capture

There are a number of methods and processes that could be used to capture CO₂ from dilute exhaust gases produced by petroleum refinery process heaters. The technical feasibility of these post-combustion CO₂ capture technologies is addressed in the following paragraphs. These

²⁷ Page 73 of Strategies for the Commercialization and Development of Greenhouse Gas Intensity-Reducing Technologies and Practices, January 2009; <http://www.climatechange.gov/Strategy-Intensity-Reducing-Technologies.pdf>

processes are divided into three areas: separation with sorbents and solvents, cryogenic separation, and membrane separation.

3.3.5.2.1 *Separation with sorbents and solvents.*

There are many sorbents and solvents under development for the separation of CO₂ from combustion flue gases through physical and/or chemical absorption/adsorption. These processes are similar in that they have a CO₂ capture section and a sorbent/solvent regeneration section. The most commercial of these processes use monoethanolamine (“MEA”) as the solvent. Monoethanolamine solvent has the advantage of fast reaction with CO₂ at low partial pressure. The primary concerns with MEA and other amine solvents are corrosion in the presence of O₂ and other impurities, high solvent degradation rates due to reactions with SO₂ and NO_x, and the large amount of energy required for solvent regeneration.²⁸ Because the HEC process heaters will be fueled exclusively with refinery fuel gas, it is anticipated that the MEA based systems are technically feasible.

Available physical absorption processes include UOP’s Selexol™ process and Lurgi’s Rectisol™ process. These processes are commonly used for CO₂ rejection from natural gas and synthesis gases. Use of physical absorption for CO₂ capture from combustion exhaust gas would entail a significant amount of gas compression capacity resulting in high energy use. Although the use of a physical absorption process is technically feasible, these processes would have higher costs relative to using MEA or other amine based solvents.

Extensive research work is ongoing evaluating the use of solid sorbents as a means of chemical absorption and the development of solvent sorbents that may have lower costs relative to MEA systems. For example DOE/NETL’s post-combustion CO₂ control technology research and development includes projects directed at the use of solid sorbents. Solid sorbents can be used to capture CO₂ from flue gas through chemical adsorption, physical adsorption, or a combination of the two effects. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. DOE/NETL is currently funding multiple post-combustion CO₂ emission control projects within each of these approaches. These research and development efforts are being performed both externally by research organizations and academic institutions, and internally through NETL’s Office of Research and Development (ORD), specifically the Separations and Fuels Processing Division and the Office of Computational Dynamics.²⁹ However, these processes have not been commercially developed and as such are not considered available or technically feasible.

3.3.5.2.2 *Cryogenic separation.*

The cryogenic CO₂ capture (CCC) process includes the following process steps:

- Dry and cool the combustion flue gases,
- Compresses the cooled and dried flue gases,

²⁸ Examples of processes that are commercially demonstrated on combustion flue gases include Fluor’s Econamine FG PlusSM and Mitsubishi Heavy Industries’ KS-1 CO₂ Recovery Process.

²⁹ Department of Energy National Energy Research Laboratory at <http://www.netl.doe.gov/technologies/coalpower/ewr/co2/PostCombustion.html>

- Further cool the compressed flue gases to a temperature slightly above the point where CO₂ forms a solid,
- Further cools compressed flue gases by expansion which precipitates the CO₂ as a solid,
- Further pressurize the CO₂ to a liquid, and
- Reheat the CO₂ and the remaining flue gas by cooling the incoming flue gases.

The final result is the CO₂ in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. The CO₂ capture efficiency for the CCC process depends primarily on the pressure and temperature at the end of the expansion process, and can be as high as 99 percent.³⁰ As with the other CO₂ separation technologies, this process has not been commercially demonstrated on gas streams having low CO₂ concentrations and containments and is therefore not considered to be technically feasible for application to the HEC petroleum refinery.

3.3.5.2.3 Membrane separation.

This method is commonly used for CO₂ removal from natural gas at high pressure and high CO₂ concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO₂ from flue gas. Membrane technology is not fully developed for low CO₂ concentrations and gas flow at the scale required for the process heaters at the HEC petroleum refinery and is not considered technically feasible for this application.³¹

3.3.6 Eliminating SCR

Elimination of SCR from the design of the process heaters at the HEC petroleum refinery is technically feasible and would be expected to result in lower N₂O emission rates.

3.4 Step 3 – Characterize Control Effectiveness of Technically Feasible Control Options

The use of good combustion practices, low-carbon fuels, and energy-efficient design to reduce GHG emissions from process heaters is inherent in the design of the HEC petroleum refinery and is considered the baseline condition. The only technically feasible strategies for further controlling GHG emissions from the process heaters at the HEC petroleum refinery are CCS, for reductions in CO₂ emissions, and elimination of SCR, for reductions in N₂O emissions.

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best CO₂ capture option, and the use of depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 93 percent effective, resulting in a GHG emission reduction of approximately 4.5 million tons CO₂e per year.

³⁰ "Cryogenic CO₂ Capture to Control Climate Change Emissions." Stephanie Burt *et. al*; Brigham Young University Provo, UT 84602.

³¹ See, for example, U.S. Department of Energy National Energy Research Laboratory at www.netl.doe.gov/technologies/coalpower/ewr/co2/PostCombustion.html.

No data are available to quantify the effect of SCR on N₂O formation in process heater exhaust gas. For the purposes of the following analysis, it is conservatively assumed that 100 percent control of N₂O emissions would be achieved by eliminating SCR from the design of the twenty heaters. This control option is therefore assumed for the purposes of the following analysis to be capable of achieving a GHG emission reduction of approximately 2,400 tons CO₂e per year. Of course, the GHG emission reduction actually achievable is far less than 100 percent and 2,400 tons CO₂e per year; these conservative estimates are used for comparative purposes only.

3.5 Step 4 – Evaluate More Effective Control Options

Eliminating SCR and using CCS to reduce GHG emissions from the process heaters at the HEC petroleum refinery would have substantial impacts on the facility in many respects, as discussed in detail below.

3.5.1 Elimination of SCR

In issuing the final PSD permit for the HEC in August 2009, DENR determined that a NO_x emission limit of 0.006 lb/MMBtu heat input, based on the use of low-NO_x burners in combination with SCR, represented BACT for twenty of the refinery fuel gas-fired process heaters. Assuming that the achievable NO_x emission level with only low-NO_x burners for NO_x control at these heaters would be 0.025 lb/MMBtu heat input, elimination of SCR would result in an increase in allowable NO_x emissions of 661 tons per year. This increase significantly outweighs the reduction in N₂O emissions that could be achieved by eliminating SCR, and RTP considers this to be an unacceptable, adverse environmental impact. Elimination of SCR therefore does not represent BACT for GHG emissions.

3.5.2 Carbon Capture and Storage

3.5.2.1 Design Considerations

As shown in Table 1.2-1, emissions of CO₂ from the thirty process heaters are approximately 4.9 million tons per year. This represents approximately 27 percent of the CO₂ emissions from the HEC, but these process heaters are scattered throughout the facility. As a result, multiple scrubbers would be installed in order to implement this control option, as it would be more economical to pump the solvent to various locations throughout the refinery than it would be to duct all of the flue gases into a single MEA scrubbing system. The CO₂-rich solvent from the scrubbers would then be pumped to a regeneration system for CO₂ removal and reuse. Specifically, the exhaust streams from the thirty process heaters would be combined into ten combined furnace stacks located in the Delayed Coking Units (2), Continuous Catalytic Reformers (2), the Crude and Vacuum Units (2), the Hydrocracking Units (2), the Naphtha and Distillate Hydrotreating Units (1), and the Oleflex Unit (1). An MEA scrubbing system would be located at each of these units for CO₂ capture.

Figure 3-1 shows the HEC plot plan and the locations of the MEA scrubbing systems. (This figure also shows the location of the CO₂ vents from the acid gas removal process as discussed in Chapter 2 herein.) It is assumed that MEA absorption systems would be used to scrub the CO₂

from the process heater flue gases. The MEA is regenerated with steam to produce a CO₂-rich stream. The CO₂ stream would need to be dried, compressed from low pressure up to 2000 pounds per square inch, and transported by an approximately 300 mile-long pipeline to an appropriate storage site, as discussed in Section 2.5 herein.

3.5.2.2 Impacts Analysis

The use of CCS for the process heaters at the HEC petroleum refinery would entail significant, adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable EOR site the approximately 4.5 million tons per year of CO₂ available for capture from the process heaters would require the equivalent of 815 MW of electric power and steam generation capacity. If all of the power generation is based on combined-cycle combustion turbines firing natural gas, the increase in fuel use would increase annual emissions of conventional air pollutants by approximately 268 tons of PM-2.5, 132 tons of NO_x, 77 tons of SO₂, 81 tons of CO, and 21 tons of VOC. The estimated capital costs for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately \$307 million. The levelized annual costs, including operating costs, are estimated to be approximately \$305 million per year. The resulting cost of CCS is approximately \$104 per ton of CO₂ sequestered. (See Appendix B for details regarding these impacts.) This cost effectiveness assumes that the revenue from EOR is equal to the long term cost of monitoring, operating, and maintaining the storage facility. These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the process heaters at the HEC petroleum refinery.

3.6 Step 5 – Establish BACT

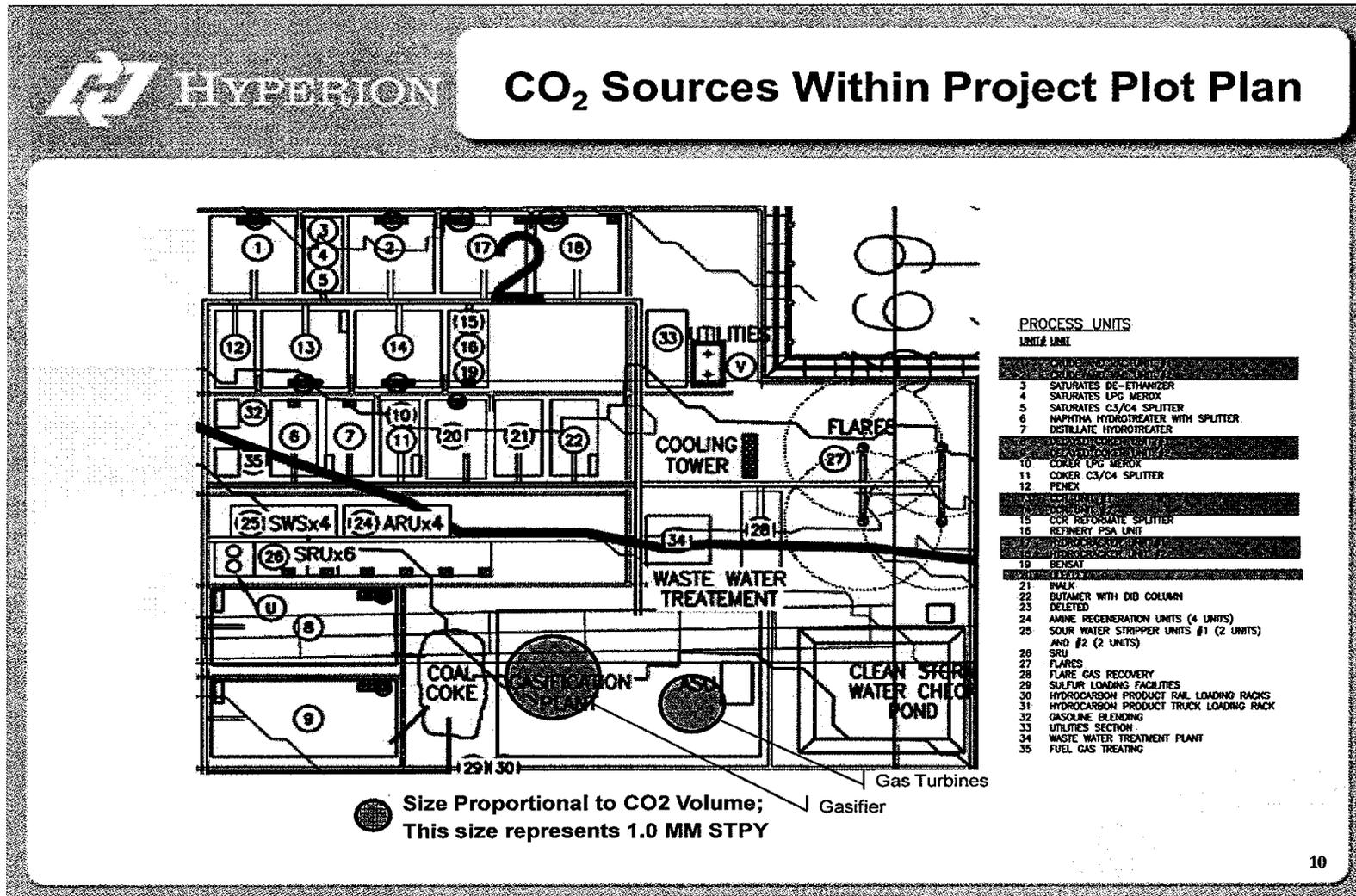
No control option more effective than the inherent design has been identified as BACT for GHG emissions from the process heaters at the HEC petroleum refinery. RTP proposes that BACT for process heaters at the HEC petroleum refinery be established based on the following design elements and work practices:

- Use of low carbon refinery fuel gas;
- Use of good combustion practices to ensure complete combustion and to minimize energy use;
- Use of combustion air preheating at large process heaters making up approximately 70 percent of process heater heat input;
- Use of process heat to generate steam;
- Use of process heat integration between and in process units;
- Use of continuous excess air monitoring; and
- Use of cogeneration for process steam and electricity requirements.

RTP proposes that a single GHG emission limit be established for all process heaters at the HEC petroleum refinery. The proposed emission limit is 33.4 tons CO₂e per thousand barrels crude charge on an annual average basis. This proposed limit reflects the potential GHG emissions of

4.88 million tons CO₂e per year, as reflected in Table 1-1 herein, and the nominal refinery crude charge capacity of 400,000 barrels per day.

FIGURE 3-1. HEC PLOT PLAN AND THE LOCATION OF THE TEN PROCESS HEATER STACKS AND CO₂ SCRUBBERS



Chapter 4. GHG BACT For Combined Cycle Gas Turbines

As described in Section 2.1.2 of the December 2007 permit application for the HEC petroleum refinery and IGCC power plant, Hyperion is considering two configurations for the power plant: a “maximum coke design case” and a “natural gas design case.” In the former case, the combustion turbines and heat recovery steam generators will be fed with cleaned syngas and PSA tail gas, both derived from petroleum coke and/or coal. Ultra low sulfur distillate fuel oil will be used as startup and backup fuel, with a maximum of 500 equivalent hours per year for each unit. In the latter case, the combustion turbines will be fired with natural gas and the heat recovery steam generators will be fired with PSA offgas derived from petroleum coke. These fossil fuel-fired combustion sources will emit three GHG’s: CH₄, CO₂, and N₂O.

Methane is emitted from combustion devices burning syngas, PSA tail gas, distillate fuel oil, and natural gas as a result of incomplete combustion. Although CH₄ emissions can be reduced by operating the combustion devices at higher flame temperatures, higher excess oxygen levels, and increased residence time, these techniques for reducing CH₄ emissions can increase NO_x emissions. Consequently, achieving low CH₄ and NO_x emission rates is a balancing act in the combustor design and operation.

Carbon dioxide will be emitted from the combined-cycle gas turbines because it is a combustion product of any carbon-containing fuel. However, relative to many other types of fossil fuel-fired power plants, the fuels to be burned at the HEC are low-carbon fuels and will produce exhaust streams that are dilute in CO₂ concentration. Thus, as discussed in detail below, full capture of CO₂ emissions from this plant is inefficient, challenging, and costly.

Nitrous oxide will be emitted from the combined cycle gas turbines in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process and due to catalytic reduction reactions in the SCR systems used for NO_x control.³²

4.1 BACT Baseline.

There are no applicable NSPS or NESHAP rules that would establish a baseline GHG emission rate for the combined-cycle gas turbines at the HEC.

³² See, for example, EPA Air Pollution Control Cost Manual, 6th Ed. EPA-452/B-02-001. Section 4.2, Chapter 2, “Selective Catalytic Reduction.” U.S. EPA. October 2000.

4.2 Step 1 – Identify Control Options

The potentially available control technologies for CH₄ emissions from combined-cycle gas turbines fired with syngas, PSA tail gas, distillate fuel oil, and natural gas are the same as those discussed, with respect to CO and VOC emissions from combined-cycle gas turbines, in Sections 4.13.3 and 4.13.4 of the December 2007 permit application for the HEC. These are as follows:

- Good Combustion Practices
- EM_xTM
- Oxidation Catalyst

Each of these technologies, as discussed below, is designed to oxidize CH₄ and other carbon-containing compounds in fuel to form CO₂. For the purposes of this BACT analysis, for the reasons discussed in Section 3.2 herein, RTP has concluded that the identified control options are considered as providing beneficial environmental impacts through oxidation of CH₄ and other carbon-containing compounds in fuel to form CO₂.

The potentially available control technologies for CO₂ emissions from combined-cycle gas turbines fired with natural gas, syngas, PSA offgas, distillate fuel oil, and natural gas are energy-efficient design in order to minimize the amount of fuel combusted; the use of low-carbon fuels in order to minimize the formation of CO₂ from fuel combustion; and CCS, as discussed in Section 2.2 herein.

The only identified control technologies for the control of N₂O from combined-cycle gas turbines are aggressively energy-efficient design, in order to minimize the amount of fuel combusted, and elimination of SCR.

4.2.1 Good Combustion Practices

Good combustion practices for combined-cycle gas turbines fired with syngas, PSA offgas, distillate fuel oil, and natural gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation practices;
- High temperatures and low oxygen levels in the primary combustion zone; and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CH₄ emissions. Combustion efficiency is related to the three “T’s” of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed

into the combined-cycle gas turbines to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through unit design and operation.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels will result in relatively high CH₄ levels and can also affect NO_x formation. Increased excess air levels will reduce the emissions of CH₄ up to the point that so much excess air is introduced that the overall combustion temperatures begin to drop significantly. If combustion temperatures drop significantly, then unit efficiency is negatively affected. Low excess air levels lower combustion temperatures and do not allow sufficient oxygen to allow efficient combustion of CH₄ but does reduce the formation of thermal NO_x. Combustion turbines and heat recovery steam generators operate within a narrow range of excess air levels due to the interrelationships between oxygen levels, combustion efficiency, formation of NO_x, and products of incomplete combustion such as CH₄.

4.2.2 Oxidation Catalyst

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH₄ emissions. This technology utilizes excess air present in the combustion exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Reactants are introduced into a catalytic bed, with the optimum temperature range for these systems being approximately 850 °F to 1,100 °F. No chemical reagent addition is required.

4.2.3 Low-Carbon Fuel

Table 3-1 presents the amount of CO₂ formed when combusting fossil fuels, including the fuels that will be used at the HEC.

<u>Fuel</u>	<u>Pounds CO₂ per Million Btu</u>
Petroleum Coke	225 *
Coal	210 *
Residual Oil	174 *
Diesel	161 *
HEC Refinery Fuel Gas	≈ 129
Natural Gas	117 *
PSA Tail Gas	≈ 100
HEC Syngas	≈ 50
* Energy Information Administration at http://www.eia.doe.gov/oiaf/1605/coefficients.html	

As shown in Table 4-1, the use of gaseous fuels, such as syngas and natural gas, reduces the production of CO₂ during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils).

4.2.4 Energy Efficient Design

A highly efficient power plant at a petroleum refinery such as the HEC reduces the amount of fuel used to produce the heat and electrical power required for the refining process. This reduction in fuel corresponds directly to the amount of GHG produced. Elements of a highly energy-efficient design for the IGCC power plant at the HEC will include the following.

4.2.4.1 Continuous Excess Air Monitoring and Control

Excessive amounts of combustion air in heat recovery steam generators results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. This requires the installation of an oxygen monitor in the stack and damper controls on the combustion air dampers. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only GHG emissions but also NO_x emissions. The combined-cycle gas turbines at the HEC IGCC power plant will be equipped with oxygen monitors as part of the continuous emission monitoring system.

4.2.4.2 Cogeneration as a CO₂ Reduction Technique

The HEC will make use of IGCC to cogenerate steam and electricity using a low value fuel, petroleum coke generated at the refinery. This approach is more energy efficient than purchasing electricity from an electric utility and generating steam by burning coke, residual oil, or natural gas.

4.2.5 Carbon Capture and Storage

As discussed in Chapter 2 herein, CCS can be used to reduce atmospheric emissions of CO₂ after formation. However, unlike the exhaust stream associated with the acid gas removal process, the inherent design of the combined-cycle gas turbines at the HEC will produce a number of dilute CO₂ streams, such that separation of CO₂ from other exhaust gas constituents (*i.e.*, “capture”) is much more difficult and costly.

The CO₂ emissions from the combustion sources at the HEC can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO₂ exhaust gas is generated.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO₂ from the combustion exhaust gases. Because the air used for combustion contains 79 percent nitrogen and because the fuels that will be

combusted at the IGCC power plant are low-carbon fuels, the CO₂ concentration in the exhaust gases is less than 5 percent.

In addition to these capture techniques, in order to provide effective reduction of CO₂ emissions, methods of compression, transport, and storage also would be required. Available methods are discussed in Chapter 2 herein.

4.2.6 Eliminating SCR

Use of SCR in order to achieve the BACT emission limits for NO_x is expected to contribute to N₂O emissions from the combined-cycle gas turbines. Eliminating this control technology would be expected to result in lower N₂O emission rates.

4.3 Step 2 – Eliminate Technically Infeasible Control Options

Four of the five categories of control options identified in Section 3.2 are technically feasible for application to the process heaters at the HEC petroleum refinery for control of GHG emissions.

4.3.1 Good Combustion Practices

Good combustion practices, as described in Section 4.2.1 herein, are technically feasible and are inherent in the design of the combined-cycle gas turbines at the HEC IGCC power plant.

4.3.2 Oxidation Catalyst

Oxidation catalyst is a technically feasible option for control of GHG emissions from, and is already planned for use in, the combined-cycle gas turbines at the HEC IGCC power plant.

4.3.3 Low-Carbon Fuels

The combined-cycle gas turbines at the HEC IGCC power plant will be fueled with low-carbon fuels. There are no control options involving the use of low-carbon fuels in these units that represent technically feasible options for reducing GHG emissions relative to the proposed fuel mix.

4.3.4 Energy Efficiency

Each of the strategies for energy-efficient design identified in Section 4.2.4 herein is technically feasible for application to the HEC IGCC power plant and is inherent in the design of the facility.

4.3.5 Carbon Capture and Storage

As discussed in Chapter 2 herein, there are available and technically feasible methods for compression, transport, and storage of concentrated CO₂ streams. Options for capturing CO₂ emissions from combined-cycle gas turbines, which would be required as an element of CCS as a GHG emission control option, are discussed below.

4.3.5.1 Pre-Combustion CO₂ Capture

The pre-combustion technique for CO₂ separation involves substituting pure oxygen for air in the combustion process. This “oxyfuel” process has not yet been tested or demonstrated in a large-scale facility.³³ Accordingly, CCS involving pre-combustion CO₂ separation and capture is not technically feasible for the combined-cycle gas turbines at the HEC IGCC power plant.

4.3.5.2 Post-Combustion CO₂ Capture

There are a number of methods and processes that could be used to capture CO₂ from dilute exhaust gases produced by the combined-cycle gas turbines at the HEC IGCC power plant. As discussed in Section 3.3.5.2 herein, capture using physical or chemical absorption techniques are assumed for the purposes of this analysis to be technically feasible.

4.3.6 Eliminating SCR

Elimination of SCR from the design of the combined-cycle gas turbines at the HEC IGCC power plant is technically feasible and would be expected to result in lower N₂O emission rates.

4.4 Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The use of good combustion practices, oxidation catalyst, low-carbon fuels, and energy-efficient design to reduce GHG emissions from combined-cycle gas turbines is inherent in the design of the HEC IGCC power plant and is considered the baseline condition. The only technically feasible strategies for further controlling GHG emissions from the combined-cycle gas turbines are CCS, for reductions in CO₂ emissions, and elimination of SCR, for reductions in N₂O emissions.

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best CO₂ capture option, and the use of depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 90 percent effective, resulting in a GHG emission reduction of approximately 3.1 million tons CO₂e per year.

No data are available to quantify the effect of SCR on N₂O formation in gas turbine exhaust gas. For the purposes of the following analysis, it is conservatively assumed that 100 percent control of N₂O emissions would be achieved by eliminating SCR from the design of IGCC power plant. This control option is therefore assumed for the purposes of the following analysis to be capable of achieving a GHG emission reduction of approximately 2,000 tons CO₂e per year. Of course, the GHG emission reduction actually achievable is far less than 100 percent and 2,000 tons CO₂e per year; these conservative estimates are used for comparative purposes only.

³³ Page 73 of Strategies for the Commercialization and Development of Greenhouse Gas Intensity-Reducing Technologies and Practices, January 2009; <http://www.climatechange.gov/Strategy-Intensity-Reducing-Technologies.pdf>

4.5 Step 4 - Evaluate More Effective Control Options

Eliminating SCR and using CCS to reduce GHG emissions from the combined-cycle gas turbines at the HEC IGCC power plant would have substantial impacts on the facility in many respects, as discussed in detail below.

4.5.1 Elimination of SCR

In issuing the final PSD permit for the HEC in August 2009, DENR determined that NO_x emission limits of 2.0 to 6.0 parts per million by volume, based on the use of SCR, represented BACT for the combined-cycle gas turbines. Assuming that the achievable NO_x emission level with only low-NO_x burners for NO_x control at these heaters would be 0.057 lb/MMBtu heat input, elimination of SCR would result in an increase in allowable NO_x emissions of 1,150 tons per year. This increase significantly outweighs the reduction in N₂O emissions that could be achieved by eliminating SCR, and RTP considers this to be an unacceptable, adverse environmental impact. Elimination of SCR therefore does not represent BACT for GHG emissions.

4.5.2 Carbon Capture and Storage

4.5.2.1 Design Considerations

As shown in Table 1.2-1, emissions of CO₂ from the combined-cycle gas turbines at the HEC IGCC power plant are approximately 3.5 million tons per year. This represents approximately 19 percent of the CO₂ emissions from the HEC. As reflected in Figure 3-1, the exhaust from all five turbines would be ducted to a single MEA scrubbing system and a single exhaust stack. The CO₂-rich solvent from the scrubber would then be pumped to a regeneration system for CO₂ removal and reuse.

It is assumed that MEA absorption systems will be used to scrub the CO₂ from the combustion turbine and large process heater flue gases. The MEA is regenerated with steam to produce a CO₂-rich stream. The CO₂ stream will need to be dried, compressed from low pressure up to 2000 pounds per square inch, and transported by an approximately 300 mile-long pipeline to an appropriate storage site.

4.5.2.2 Impacts Analysis

The use of CCS for the combined-cycle gas turbines at the HEC IGCC power plant would entail significant, adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable EOR site the approximately 3.5 million tons per year of CO₂ available for capture from the combined-cycle gas turbines would require the equivalent of 226 MW of electric power and steam generation capacity. If all of the power generation is based on combined-cycle combustion turbines firing natural gas, the increase in fuel use would increase annual emissions of conventional air pollutants by approximately 148 tons of PM-2.5, 73 tons of NO_x, 42 tons of SO₂, 44 tons of CO, and 11 tons of VOC. The estimated capital costs

for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately \$637 million. The levelized annual costs, including operating costs, are estimated to be approximately \$262 million per year. The resulting cost of CCS is approximately \$124 per ton of CO₂ sequestered. (See Appendix C for details regarding these impacts.) This cost effectiveness assumes the revenue from EOR is equal to the long term cost of monitoring, operating, and maintaining the storage facility. These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the combined-cycle gas turbines at the HEC IGCC power plant.

4.6 Step 5 - Establish BACT

No control option more effective than the inherent design has been identified as BACT for GHG emissions from the combined-cycle gas turbines at the HEC IGCC power plant. RTP proposes that BACT for these turbines at the HEC petroleum refinery be established based on the following design elements and work practices:

- Use of good combustion practices to ensure complete combustion and to minimize energy use;
- Use of process heat to generate steam;
- Use of process heat integration between and in process units;
- Use of continuous excess air monitoring; and
- Use of cogeneration for process steam and electricity requirements.

RTP proposes that a single GHG emission limit be established for all combined-cycle gas turbines at the HEC IGCC power plant. The proposed emission limit is 23.9 tons CO₂e per thousand barrels crude charge on an annual average basis. This proposed limit reflects the potential GHG emissions of 3.48 million tons CO₂e per year, as reflected in Table 1-1 herein, and the nominal refinery crude charge capacity of 400,000 barrels per day.

Chapter 5. GHG BACT for Small Combustion Sources

In addition to the thirty process heaters in the petroleum refinery and the five combined-cycle gas turbines in the IGCC power plant, the HEC will include six flares, four emergency generators, two fire water pumps, four thermal oxidizers, and eight gasifier startup burners. As shown in Table 1-1, these small combustion sources will emit *de minimis* quantities of three GHG's: CH₄, CO₂, and N₂O. As shown in Table 1-1, total GHG emissions from these units are 20,600 tons CO₂e per year.

5.1 BACT Baseline

There are no applicable NSPS or NESHAP rules that would establish baseline GHG emission rates for the small combustion sources at the HEC petroleum refinery and IGCC power plant.

5.2 Step 1 – Identify Control Options

The only identified control technology for CH₄ emissions from small combustion sources is oxidation catalyst. This technology, as discussed below, is designed to oxidize CH₄ and other carbon-containing compounds in fuel to form CO₂. For the purposes of this BACT analysis, for the reasons discussed in Section 3.2 herein, RTP has concluded that this control option is considered as providing beneficial environmental impacts through oxidation of CH₄ and other carbon-containing compounds in fuel to form CO₂.

The only identified control technology for CO₂ emissions from the small combustion sources is CCS, as discussed in Section 2.2 herein.

No control technologies were identified for the control of N₂O from small combustion sources.

5.2.1 Oxidation Catalyst

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH₄ emissions. This technology utilizes excess air present in the combustion exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Reactants are introduced into a catalytic bed, with the optimum temperature range for these systems being approximately 850 °F to 1,100 °F. No chemical reagent addition is required.

5.2.2 Carbon Capture and Storage

As discussed in Chapter 2 herein, CCS can be used to reduce atmospheric emissions of CO₂ after formation. However, unlike the exhaust stream associated with the acid gas removal process, the inherent design of the small combustion sources at the HEC produce a number of dilute CO₂ streams, such that separation of CO₂ from other exhaust gas constituents (*i.e.*, “capture”) is much more difficult and costly.

The CO₂ emissions from the combustion sources at the HEC can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO₂ exhaust gas is generated.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO₂ from the combustion exhaust gases. Because the air used for combustion contains 79 percent nitrogen and because refinery fuel gas is a low-carbon fuel, the CO₂ concentration in the exhaust gases is approximately 5 percent or less.

In addition to these capture techniques, in order to provide effective reduction of CO₂ emissions, methods of compression, transport, and storage also would be required. Available methods are discussed in Chapter 2 herein.

5.3 Step 2 – Eliminate Technically Infeasible Control Options

Neither of the options for control of GHG emissions identified in Section 5.2 is technically feasible for application to the small combustion sources at the HEC.

5.3.1 Oxidation Catalyst

For the same reasons discussed in Section 4.2.3.3 of the initial permit application for the HEC, oxidation catalyst is not a technically feasible option for control of GHG emissions from the thermal oxidizers at the HEC petroleum refinery. Oxidation catalyst also is not feasible for application to flares due to their physical configuration, extremely high heat release rate in emergency use, and intermittent use. Oxidation catalyst is presumed for the purposes of this analysis to be feasible for application to gasifier startup burners and emergency engines.

5.3.2 Carbon Capture and Storage

Pre-combustion techniques for CO₂ separation have not yet been tested or demonstrated in facilities similar to the small combustion sources at the HEC. This capture technology is not technically feasible for the small combustion sources.

Post-combustion CO₂ capture technologies are not feasible for application to flares due to physical configuration, extremely high heat release rate in emergency use, and intermittent use.

Post-combustion CO₂ capture using MEA scrubbing is presumed for the purposes of this analysis to be feasible for application to gasifier startup burners, emergency engines, and thermal oxidizers. This capture technology could be applied in combination with technically feasible methods for compression, transport, and storage of concentrated CO₂ streams, as discussed in Chapter 2 herein.

5.4 Step 3 – Characterize Control Effectiveness of Technically Feasible Control Options

The only technically feasible strategy for further controlling GHG emissions from the small combustion sources at the HEC petroleum refinery is CCS as applied to gasifier startup burners, emergency engines, and thermal oxidizers.

5.5 Step 4 – Evaluate More Effective Control Option

Using CCS to reduce GHG emissions from the gasifier startup burners, emergency engines, and thermal oxidizers at the HEC would have substantial adverse impacts on the facility, is not practical, and does not represent BACT.

As shown in Table 1.2-1, emissions of CO₂ from these small combustion sources total approximately 10,000 tons per year. These emissions, from 16 separate stacks scattered throughout the facility, primarily from units that operate only intermittently, represent only 0.06 percent of the GHG emissions from the HEC.

Multiple scrubbers would be installed in order to implement this control option, as it would be more economical to pump the solvent to various locations throughout the refinery than it would be to duct all of the flue gases into a single MEA scrubbing system. The CO₂-rich solvent from the scrubbers would then be pumped to a regeneration system for CO₂ removal and reuse. The resulting CO₂ stream would be dried, compressed from low pressure up to 2000 pounds per square inch, and transported by an approximately 300 mile-long pipeline to an appropriate storage site, as discussed in Section 2.5 herein.

The use of CCS for the small combustion sources at the HEC petroleum refinery would entail significant, adverse energy, environmental, and economic impacts for procurement and installation and due to the steam and electric load requirements of these systems. As was discussed with respect to CCS for process heaters in Section 3.5.2.2 herein, these adverse impacts are disproportionate to the environmental benefit achievable. In particular, the cost effectiveness would be significantly lower (*i.e.*, the cost per ton of carbon stored would be much higher than \$124 per ton) due to the small scale and intermittent operation of the small combustion sources). Therefore, CCS does not represent BACT for the small combustion sources at the HEC petroleum refinery.

5.6 Step 5 – Establish BACT

No control option more effective than the inherent design has been identified as BACT for GHG emissions from the small combustion sources at the HEC petroleum refinery.

RTP proposes that a single GHG emission limit be established for all of the small combustion sources at the HEC petroleum refinery and IGCC power plant. The proposed emission limit is 0.2 tons CO₂e per thousand barrels crude charge on an annual average basis. This proposed limit reflects the potential GHG emissions of 22,200 tons CO₂e per year, as reflected in Table 1-1 herein, and the nominal refinery crude charge capacity of 400,000 barrels per day.

Chapter 6. GHG BACT for Equipment Leaks

The proposed HEC petroleum refinery and IGCC power plant includes piping and a large number of connectors, valves, pumps, compressors, and similar components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of CH₄ and CO₂ emissions due to leakage from rotary shaft seals, connection interfaces, valve stems, and similar points.

6.1.1 BACT Baseline

There are no applicable NSPS or NESHAP rules that would establish a baseline GHG emission rate for equipment leaks in the HEC petroleum refinery or IGCC power plant. However, GHG emissions from equipment leaks will occur by the same mechanisms as VOC emissions from equipment leaks, and the leak detection and repair (“LDAR”) program required pursuant to 40 CFR 63 subparts H and CC will provide effective control of GHG emissions. (In fact, subpart H prescribes the use of CH₄ as the reference compound in conducting required monitoring for leaks pursuant to EPA Reference Method 21, so the LDAR program already established as BACT for VOC emissions actually relies on this GHG as the basis for the monitoring and control requirements.)

The baseline requirements for the LDAR program applicable to the HEC petroleum refinery and IGCC power plant as set forth in 40 CFR 63 subparts H and CC include requirements for monitoring to detect leaks and for attempting and completing repairs of leaking components in the following categories:

- Pumps in light liquid service;
- Compressors;
- Pressure relief devices in gas/vapor service;
- Sampling connection systems;
- Open-ended valves or lines;
- Valves in gas/vapor service and in light liquid service;
- Pumps, valves, connectors, and agitators in heavy liquid service;
- Instrumentation systems;
- Pressure relief devices in liquid service;
- Surge control vessels and bottoms receivers; and
- Closed-vent systems and control devices.

6.1.2 Step 1 – Identify All Control Options

Potential enhancements to the baseline LDAR program work practice requirements include the following:

- Use a more stringent definition of a “leaking” component (*i.e.*, a lower threshold concentration as measured at the potential leak interface). This has the effect of accelerating or broadening the repair obligations for leaking components to include components that would not require repair under the NESHAP rules;
- Increased leak monitoring frequencies, which has the effect of accelerating the identification and repair of leaking components; and
- Enforceable limits on the number of leaking components.

6.1.3 Step 2 – Eliminate Technically Infeasible Control Options

All of the identified control options are technically feasible.

6.1.4 Step 3 – Characterize Control Effectiveness of Technically Feasible Control Options

The most effective of the identified control strategies is a combination of the identified control options. Specifically, this includes an LDAR program with enhanced work practices relative to the NESHAP, plus enforceable limits on percent leaking components.

Other control strategies not involving all of these enhanced work practices, or not including enforceable limits on leaking components, would be less effective.

6.1.5 Step 4 – Evaluate More Effective Control Options

The most effective identified control strategy for GHG emissions from equipment leaks, as reflected in Section 14 of the PSD permit issued to the HEC in August 2009, is proposed as BACT. This system will not result in any adverse energy or environmental impacts. Accordingly, no evaluation of alternative control options is warranted.

6.1.6 Step 5 – Establish BACT

The proposed BACT for GHG emissions from equipment leaks at the HEC covers both the petroleum refinery and the IGCC power plant. The proposed program includes all requirements of 40 CFR 63 subparts H and CC, which are applicable to the petroleum refining process units but not otherwise applicable to the IGCC power plant, and the following additional provisions:

- Leak definitions of 100 ppmv for valves and connectors in gas/vapor and light liquid service and 500 ppmv for all other components;
- Inclusion of flanges and screwed connectors in the LDAR program;
- Eliminating the provisions for designating pumps in light liquid service as “unsafe to monitor” and for monitoring these pumps with less frequency than other pumps;
- Eliminating the provisions providing for reduced monitoring frequency for valves in gas/vapor service or light liquid service;

- Underground process pipelines will contain no buried valves such that fugitive emission monitoring is rendered impractical;
- Requirements for a first attempt at repair of all leaking components within 24 hours;
- Generally requiring successful repair of leaking components in VOC service within 7 days, with delays subject to enforceable limitations on leaking components as described below; and
- Delay of repair for equipment in VOC service will be allowed only if such delay would not cause the percent leaking components to exceed any of the following:
 - 1.0 percent of the total number of pumps in light liquid service and compressors on a source-wide basis;
 - 1.0 percent of the total number of pressure relief devices on a source-wide basis;
 - 0.3 percent of the total number of connectors in gas/vapor service and connectors in light liquid service on a source-wide basis; and
 - 0.3 percent of the total number of valves in gas/vapor service and valves in light liquid service, determined on a source-wide basis.

These proposed emission limits are substantially more stringent than the BACT baseline discussed in Section 6.1.1 and are as stringent as any limits imposed on or achieved by any petroleum refinery or IGCC power plant of which RTP is aware.

APPENDIX A – IMPACTS ANALYSIS FOR HEC CO₂ VENT

PARAMETER	IGCC CO ₂ VENT	
	<u>BASELINE - No Compression, Transport, Sequestration</u>	<u>Compression+Transport+S equestration</u>
Environmental Impacts:		
CO ₂ Emitted, millions TPY	8.5	0.0
CO ₂ Incremental % Control	Baseline	100%
CO ₂ Reduced, millions TPY	Baseline	8.5
CO ₂ from Compression, millions TPY	Baseline	1.0
Net CO ₂ Reduced, millions TPY	Baseline	7.5
Increase in NO _x , TPY	Baseline	79
Increase in SO ₂ , TPY	Baseline	44
Increase in CO, TPY	Baseline	46
Increase in VOC, TPY	Baseline	12
Increase in PM2.5, TPY	Baseline	155
Energy Impacts:		
Additional Power Generation, MW	Baseline	267
NG Use, millions scf/yr	Baseline	15,567
Economic Impacts:		
Total Capital Cost	Baseline	\$649,800,000
Total Annual Cost	Baseline	\$288,700,000
CO ₂ Capture Cost Effectiveness	Baseline	\$38
CO ₂ Transport Cost Effectiveness	Baseline	\$5
CO ₂ EOR Cost Effectiveness	Baseline	-\$10
Total CO ₂ CCS Cost Effectiveness	Baseline	\$33

HEC ESTIMATED COST OF CO ₂ CAPTURE BASED ON IPCC REPORT TABLE 3.15 – IGCC CO ₂ Vent							
Parameter	Units	IGCC low	IGCC high	Parameter	Units	HEC	Comments
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMB/hr steam equivalent MW (see note below)
Emission Rate wo Capture	kgCO ₂ /MWh	628	846	Emission Rate w/o Capture	ton/year	8,541,956	From Table 1-1
Percent Reduction	%	81	91	Percent Reduction	%	100	Post Rectisol
Emission Rate w/ Capture	kgCO ₂ /MWh	65	152	Emission Rate w/ Capture	ton/year	0	
				CO ₂ Captured	ton/year	8,541,956	
Capture Energy Required	% MWh	14	25	Capture Energy Required	MW	267	Average of 14 & 25 % MWh
				NG Use for Incremental MW	MM SCFY	15,566	6,796 Btu/kwh
				Incremental CO ₂ w/ Capture	ton/year	952,669	120 lb CO ₂ /MMBtu for NG
Total Capital w/o Capture	US\$/kw	1169	1565	Total Capital w/o Capture	Millions \$	\$1,870	Average of 1169 and 1565 US\$/kw
Total Capital w/ Capture	US\$/kw	1414	2270	Total Capital w/ Capture	Millions \$	\$2,520	Average of 1414 and 2270 US\$/kw
						\$650	delta US\$
				Annualized Capital Costs	Millions \$/yr	\$97	15% of capital costs
				Annualized NG Costs	Millions \$/yr	\$159	\$10 per MMBtu for NG
				Annual O&M Costs	Millions \$/yr	\$32	5% of total capital
				Total Annual Costs	Millions \$/yr	\$289	
Cost of CO ₂ Captured	US\$/tonne CO ₂	11	32	Cost of CO ₂ Captured	\$/t CO ₂	\$34	
Cost of CO ₂ avoided	US\$/tonne CO ₂	13	37	Cost of CO ₂ avoided	\$/t CO ₂	\$38	
Note 1:	2.4	MMlb/hr steam at 720 °F/600 psig					
	1,420	Btu/lb enthalpy of 720 °F/600psig steam					
	196	minus Btu/lb enthalpy for saturated steam at 5 psig					
	2938	MMBtu/hr steam					
	861	MW in form of steam					

APPENDIX B – IMPACTS ANALYSIS FOR HEC PROCESS HEATERS

PARAMETER	<u>PROCESS HEATERS</u>	
	<u>BASELINE - No CCS</u>	<u>With CCS</u>
Environmental Impacts:		
CO ₂ Emitted, millions TPY	4.9	0.3
CO ₂ Incremental % Control	Baseline	93%
CO ₂ Reduced, millions TPY	Baseline	4.5
CO ₂ from Compression, millions TPY	Baseline	1.5
Net CO ₂ Reduced, millions TPY	Baseline	3.1
Increase in NO _x , TPY	Baseline	137
Increase in SO ₂ , TPY	Baseline	77
Increase in CO, TPY	Baseline	81
Increase in VOC, TPY	Baseline	21
Increase in PM _{2.5} , TPY	Baseline	268
Energy Impacts:		
Additional Power Generation, MW	Baseline	815
NG Use MMSCFY		23,886
Economic Impacts:		
Total Capital Cost	Baseline	\$307,000,000
Total Annual Cost	Baseline	\$305,000,000
CO ₂ Capture Cost Effectiveness	Baseline	\$99
CO ₂ Transport Cost Effectiveness	Baseline	\$5
Total CCS Cost Effectiveness	Baseline	\$104

HEC ESTIMATED COST OF CO₂ CAPTURE BASED ON CO₂ CAPTURE PROJECT -Refinery Process Heaters

Parameters	Units	Grangemouth	HEC	Comments
Refinery Size - CO ₂ Emitted	Millions st/yr	2.4	4.9	HEC From Table 1-1. HEC CO ₂ Emissions
Percent Reduction	%	93%	93%	assumed
CO ₂ Captured	Millions st/yr	2.2	4.5	
Capture Energy Required	MW fired	396	815	HEC ratioed from reference
Capture Energy Required	MMBtu/hr	1,351	2,781	HEC ratioed from reference; equivalent to 357 MW
NG Use for Incremental MW	MM SCFY	11,604	23,886	based on 1020 Btu/scf for NG
Capture Energy CO ₂	Millions st/yr	0.7	1.5	
Percent Reduction	%	93%	93%	
CO ₂ Captured	Millions st/yr	0.66	1.36	
Total Captial	Millions US\$	\$149	\$307	HEC ratioed from reference
Annualized Capital Costs	Millions US\$/yr	\$22	\$46	15% of capital costs
Annualized NG Costs @ \$10	Millions US\$/yr	\$118	\$244	\$10 per MMBtu for NG
Annual O&M Costs	Millions US\$/yr	\$7	\$15	5% of total capital
Total Annual Costs	Millions US\$/yr	\$148	\$305	
Cost of CO ₂ Captured	US\$/st CO ₂	\$67	\$67	
Cost of CO ₂ Avoided	US\$/st CO ₂	\$99	\$99	
REFERENCE: "A Study of Very Large Scale Post Combustion CO ₂ Capture At a Refining & Petrochemical Complex", Grangemouth, , UK.				

APPENDIX C – IMPACTS ANALYSIS FOR HEC IGCC COMBINED-CYCLE GAS TURBINES

PARAMETER	GAS TURBINES	
	BASELINE - No CCS	With CCS
Environmental Impacts:		
CO ₂ Emitted, millions TPY	3.5	0.5
CO ₂ Incremental % Control	Baseline	86%
CO ₂ Reduced, millions TPY	Baseline	3.0
CO ₂ from Compression, millions TPY	Baseline	0.8
Net CO ₂ Reduced, millions TPY	Baseline	2.2
Increase in NO _x , TPY	Baseline	73
Increase in SO ₂ , TPY	Baseline	42
Increase in CO, TPY	Baseline	44
Increase in VOC, TPY	Baseline	11
Increase in PM _{2.5} , TPY	Baseline	148
Energy Impacts:		
Additional Power Generation, MW	Baseline	226
NG Use MMSCFY		13,172
Economic Impacts:		
Total Capital Cost	Baseline	\$637,000,000
Total Annual Cost	Baseline	\$262,000,000
CO ₂ Capture Cost Effectiveness	Baseline	\$119
CO ₂ Transport Cost Effectiveness	Baseline	\$5
Total CCS Cost Effectiveness	Baseline	\$124

HEC ESTIMATED COST OF CO ₂ CAPTURE BASED ON IPCC REPORT TABLE 3.15 – Gas Turbines (4)							
Parameter	Units	IGCC low	IGCC high	Parameter	Units	HEC	Comments
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMBt/hr steam equivalent MW (see below)
Emission Rate wo Capture	kgCO ₂ /MWh	344	379	Emission Rate wo Capture	ton/year	3,480,306	From Table 1.2-2. HEC CO ₂ Emissions
Percent Reduction	%	83	88	Percent Reduction	%	85.5	Average of 83 & 88 % MWh
Emission Rate w Capture	kgCO ₂ /MWh	40	66	Emission Rate w Capture	ton/year	504,644	14.5% not captured
				CO ₂ Captured	ton/year	2,975,661	
Capture Energy Required	% MWh	11	22	Capture Energy Required	MW	226	Average of 11 & 22 % MWh
				NG Use for Incremental MW	MM SCFY	13,172	6,796 Btu/kwh
				Incremental CO ₂ w Capture	ton/year	806,105	120 lb CO ₂ /MMBtu for NG
Total Capital wo Capture	US\$/kw	515	724	Total Capital wo Capture	Millions \$	\$847	Average of 515 and 724 US\$/kw
Total Capital w Capture	US\$/kw	909	1261	Total Capital w Capture	Millions \$	\$1,484	Average of 909 and 1261 US\$/kw
						\$637	delta US\$
				Annualized Capital Costs	Millions \$/yr	\$96	15% of capital costs
				Annualized NG Costs	Millions \$/yr	\$134	\$10 per MMBtu for NG
				Annual O&M Costs	Millions \$/yr	\$32	5% of total capital
				Total Annual Costs	Millions \$/yr	\$262	
Cost of CO ₂ Captured	US\$/tonne CO ₂	33	57	Cost of CO ₂ Captured	US\$/st CO ₂	\$88	
Cost of CO ₂ avoided	US\$/tonne CO ₂	37	74	Cost of CO ₂ avoided	US\$/st CO ₂	\$121	
Note 1:	2.4	MMlb/hr steam at 720 oF/600 psig					
	1,420	Btu/lb enthalpy of 720F/600psig steam					
	196	minus Btu/lb enthalpy for saturated steam at 5 psig					
	2938	MMBtu/hr steam					
	861	MW in form of steam					



RTP ENVIRONMENTAL ASSOCIATES, INC.®

October 18, 2010

Mr. Kyrik Rombough
Natural Resources Engineering Director
South Dakota Department of Natural Resources
523 East Capitol
Pierre, South Dakota 57501-3182

Subject: In-Stack NO₂ to NO_x Ratio for Emergency Generators at the Proposed HEC Facility

Dear Mr. Rombough,

An in-stack NO₂/NO_x ratio of 0.21 was employed for the diesel engine exhaust in the September 2010 (Addendum 2) modeling analysis conducted for the Hyperion Energy Center (HEC). This ratio was developed based upon an analysis of diesel engine exhaust, "Diesel Exhaust Oxidant Potential Assessed by the NO₂/NO Concentration Ratio", Air Resource Board of California – Diesel Nitrogen Dioxide Working Group, April 30, 2004. Since submittal of the Addendum 2 modeling, RTP Environmental has determined that the in-stack ratio was not calculated correctly. The correct in-stack NO₂/NO_x ratio is 0.32. The ratio is calculated as the average of the four NO₂/NO_x ratios for each pair of emission test results as shown in Table 1 of the diesel exhaust paper and the attached table. The revised ratio will be employed and the Addendum 2 modeling resubmitted for your review.

Please call me at (919) 845-1422 x41 if you have any questions or require additional information.

Sincerely,

David Keen
RTP Environmental

Diesel Engine Exhaust Concentrations (ppm)				
	Emission Test Scenario			
Pollutant	A/B	C/D	E/F	G/H
NOx	423	406	467	484
NO2	24	106	191	260
NO2/NOx	0.06	0.26	0.41	0.54
Average	0.32			

From "Diesel Exhaust Oxidant Potential Assessed by the NO2/NO Concentration Ratio"