

# **Hyperion Energy Center**

## **Best Available Control Technology (BACT) Analysis for Emissions of Carbon Dioxide**

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# Chapter 1. Introduction

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## 1.1 Overview

Hyperion Refining LLC (“Hyperion”) has requested RTP Environmental Associates, Inc. (“RTP”) prepare a Best Available Control Technology (“BACT”) analyze for the increase in carbon dioxide (CO<sub>2</sub>) emissions from the Hyperion Energy Center (“HEC”) in Union County, South Dakota. This report presents the results of that analysis. It is assumed that the reader has access to the air quality permit application submitted to the South Dakota Department of Environment and Natural Resources in December 2007; the facility description and emissions calculations presented in that application are not repeated herein.

The proposed HEC will comprise a greenfield petroleum refinery and an integrated gasification combined cycle (“IGCC”) power plant. 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.

By its nature, petroleum refining requires transforming crude oil into products that can be combusted efficiently in internal combustion engines. To support the refining process, significant energy sources are required to provide process heat, steam, electricity and hydrogen. The HEC is unique in that it is designed to be nearly self-sufficient with regard to generation of hydrogen, steam, and electric power. This self-sufficiency will be achieved using petroleum coke that is produced on site, as a byproduct of the refining process, as the fuel source for the gasification process.

## 1.2 CO<sub>2</sub> Emissions

As with other refineries, the carbon input to the HEC will be primarily in the form of crude oil feedstock and will include other sources such as natural gas. In the HEC, approximately 82 percent of the carbon entering the facility will exit in the form of liquid fuel products, primarily gasoline and diesel fuel. The remaining approximately 18 percent of carbon input will exit as CO<sub>2</sub> emissions resulting from the combustion and chemical processes used to produce the heat, steam, electricity, and hydrogen required by the refinery.

The HEC will produce approximately 19 million short tons per year (STPY) of CO<sub>2</sub>. These emissions will occur primarily from three categories of emissions units:

- Petroleum coke gasification process (approximately 50 percent of total),
- Combustion turbines in the power block (approximately 26 percent of total), and
- Refinery process heaters (approximately 24 percent of total).

Carbon dioxide 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 CO<sub>2</sub>. Full oxidation of fuel carbon to CO<sub>2</sub> 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 CO<sub>2</sub> in the atmosphere.

Table 1.2-1 presents the amount of CO<sub>2</sub> formed when combusting fossil fuels, including the fuels that will be used at the HEC.

<u>FUEL</u>	<u>Pounds CO<sub>2</sub> per Million Btu</u>
Petroleum Coke	225 *
Coal	210 *
Residual Oil	174 *
Refinery Fuel Gas	≈ 120
Natural Gas	117 *
HEC Syngas	≈ 76
* Energy Information Administration at <a href="http://www.eia.doe.gov/oiaf/1605/coefficients.html">http://www.eia.doe.gov/oiaf/1605/coefficients.html</a>	

As the table shows, gaseous fossil fuels contain the least amount of carbon and solid fossil fuels contain the highest amount of carbon. The primary other combustible element in fossil fuels is hydrogen, which when combusted or oxidized becomes water vapor.

Unlike fossil fuel-fired electric power plants, which emit CO<sub>2</sub> from one stack or a small number of stacks located in proximity to one another, petroleum refinery CO<sub>2</sub> emissions are generated and emitted from sources and stacks scattered throughout the facility. As such, full capture of CO<sub>2</sub> emissions from the many stacks located throughout the HEC would be inefficient, challenging, and costly. Additionally, most of CO<sub>2</sub>-emitting units at the HEC combust relatively low-carbon refinery fuel gas and natural gas, yielding exhaust gas CO<sub>2</sub> concentrations half that of solid fuel combustion sources. Table 1.2-2 lists the CO<sub>2</sub>-emitting units at the HEC and the quantities of CO<sub>2</sub> emitted.

### **1.3 Premise for BACT Analysis**

Under federal and South Dakota law and regulations, the requirement for BACT applies to pollutants that are subject to regulation under the federal Clean Air Act. Current regulations do not extend to CO<sub>2</sub>, so BACT is not applicable to CO<sub>2</sub> emissions from the HEC. However, Hyperion and RTP recognize adding CO<sub>2</sub> emissions is an important issue, on which the political, regulatory, and legal framework may be changing. For purposes of this analysis, RTP assumes, *arguendo*, that CO<sub>2</sub> is subject to the BACT requirement applicable to regulated pollutants under 40 CFR § 52.21.

<b>Table 1.2-2. HEC CO<sub>2</sub> Emissions</b>					
# of Units <sup>1</sup>	Fuel	Max. Firing Rate [MMBtu/hr]	Emission Rate Total [ton/yr]	Emission Rate per Unit [ton/yr]	% of Total
	<b>IGCC</b>	(HHV)			
2	CO2 Vent	NA	8,541,956	4,270,978	48%
4	Combustion Turbines	1677.4	3,986,530	996,633	23%
	<b>PROCESS HEATERS</b>				
2	CCR Platforming	824.52	933,155	466,577	5%
2	Hydrocracker Frac Section	675.52	764,524	382,262	4%
1	Oleflex	604.43	342,037	342,037	2%
2	CDU/VDU	530.15	600,002	300,001	3%
2	CCR Platforming	492.85	557,792	278,896	3%
1	NHT with Splitter	246.84	139,684	139,684	1%
2	Delayed Coker Unit	242.46	274,401	137,201	2%
2	Delayed Coker Unit	242.46	274,401	137,201	2%
2	CDU/VDU	214.66	242,946	121,473	1%
1	NHT with Splitter	199.60	112,949	112,949	1%
1	NHT with Splitter	168.78	95,507	95,507	1%
1	DHT	140.55	79,533	79,533	0%
1	CCR Reformate Splitter	138.00	78,090	78,090	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	64.91	73,457	36,729	0%
2	Hydrocracker Rxn Section	64.91	73,457	36,729	0%
	<b>MISCELLANEOUS</b>				
17	SRUs, Flares, etc.	NA	264,110	15,536	1%
			17,661,544		

As with the BACT analyses performed for regulated pollutants, this BACT analysis for CO<sub>2</sub> covers only emissions occurring from emissions units at the HEC. Emissions that will occur offsite due to combustion of the transportation fuels produced at the HEC are not subject to the BACT requirement. Similarly, this analysis does not cover CO<sub>2</sub> emissions that may occur at other sites or facilities to which CO<sub>2</sub>-containing exhaust gases from the HEC may be transferred or transported. This BACT analysis conservatively assumes that any CO<sub>2</sub> that is captured at the HEC and transported offsite for use or disposal, such as through sequestration, will be 100 percent effective. In practice, the effectiveness of such disposition would be less, and some fraction of the CO<sub>2</sub> emissions capture that would be achieved at the HEC would be emitted from transportation pipelines or offsite sources. Those emissions are omitted from this analysis for simplicity, which may have the effect of overstating the environmental benefit of certain CO<sub>2</sub> control options considered in the analysis.

<sup>1</sup> There will actually be 5 combustion turbines, including one spare. Emissions are calculated as if four units will operate continuously at 100 percent capacity; in actuality, all five units will operate at less than 100 percent capacity.

# Chapter 2. BACT Overview

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## 2.1 Best Available Control Technology Definition

The PSD regulations define BACT at 40 CFR § 52.21(b)(12) as follows:

“[BACT] means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.”

## 2.2 Methodology for BACT Analyses

The PSD regulations do not prescribe a procedure for conducting BACT analyses. Instead, the U.S. EPA has consistently interpreted the BACT requirement as containing two core criteria: First, the BACT analysis must include consideration of the most stringent available technologies, *i.e.*, those that provide the “maximum degree of emissions reduction.” Second, any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

U.S. EPA has developed what it terms the “top-down” approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the “top-down” approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down approach was utilized in this BACT analysis.

The five basic steps of a top-down BACT analysis are listed below:

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

## **2.3 BACT Baseline**

The statutory definition of BACT states:

“In no event shall application of ‘best available control technology’ result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of [the Clean Air Act].”

Because CO<sub>2</sub> is not currently regulated under sections 111 or 112 of the Clean Air Act, there are no regulatory CO<sub>2</sub> emission limitations that would establish a control technology “baseline” for this BACT analysis. The performance and costs of identified CO<sub>2</sub> control technologies are therefore compared to uncontrolled baselines in this analysis.

## **2.4 BACT Technical Feasibility Criteria**

In the second step of the BACT analysis, control technologies are evaluated for technical feasibility. Technical infeasibility will be demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option. In addition, the technology must be commercially available for it to be considered as a candidate BACT technology. U.S. EPA’s draft New Source Review Manual summarizes the technical feasibility criteria as follows:

Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.

In general, a technically feasible control technology is one that has been demonstrated to function efficiently on an emissions unit that is identical or similar to the emissions unit under review. For the purposes of assessing technical feasibility, the determination of whether an emissions unit should be considered to be identical or similar is based upon the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emissions unit may not be technically feasible for an apparently similar source depending on differences in physical and chemical gas stream characteristics.

# Chapter 3. BACT for CO<sub>2</sub> Vents

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## 3.1 Step 1 – Identify Control Options

The only identified strategy for mitigating CO<sub>2</sub> emissions from the acid gas removal process at the HEC is carbon capture and storage (“CCS,” also referred to as “carbon capture and sequestration”). As indicated by the name, this technique involves capturing CO<sub>2</sub>, transporting it as necessary, and permanently storing it instead of releasing it into the atmosphere. The process involves three main steps:

- Capturing CO<sub>2</sub> at its source by separating it from other gases produced by an industrial process;
- Transporting the captured CO<sub>2</sub> to a suitable storage location (typically in compressed form); and
- Storing the CO<sub>2</sub> 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. 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.

### 3.1.1 Capture

Isolation of relatively pure CO<sub>2</sub> is inherent to the acid gas removal process at the HEC.

### 3.1.2 Transportation

As discussed in Section 3.1.3, below, 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 CO<sub>2</sub> 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 CO<sub>2</sub> over long distances.

The oldest long-distance CO<sub>2</sub> 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 CO<sub>2</sub> pipelines have been constructed since then, mostly in the mid-continent, Western United States, to transport CO<sub>2</sub> for EOR. These pipelines carry CO<sub>2</sub> 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 CO<sub>2</sub> pipeline operate today in the United States.

Pipeline transportation of CO<sub>2</sub> is typically accomplished with CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> source and where the CO<sub>2</sub> is injected, and booster compressors located as needed along the pipeline. In overall construction, CO<sub>2</sub> 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.

### **3.1.3 Storage**

There are several options being explored and employed for permanent storage of CO<sub>2</sub>. 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 CO<sub>2</sub> with metal oxides to produce stable carbonates, and terrestrial sequestration.

## **3.2 Step 2 – Eliminate Technically Infeasible Control Options**

Capture, compression, and transportation of CO<sub>2</sub> from the acid gas removal process at the HEC are technically feasible. Of the CO<sub>2</sub> storage options listed in Section 3.1.3, only a limited number are technically feasible, as discussed below.

### **3.2.1.1 Geologic Formations**

The geologic formations considered appropriate for CO<sub>2</sub> 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 CO<sub>2</sub> is injected into it. Under high pressure, CO<sub>2</sub> turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO<sub>2</sub> tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO<sub>2</sub> and prevent further upward migration.

There are other mechanisms for CO<sub>2</sub> trapping as well: CO<sub>2</sub> 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 CO<sub>2</sub> storage can be difficult to determine. Research is being performed today which is aimed at developing the ability to characterize a formation before CO<sub>2</sub> injection in order to predict its CO<sub>2</sub> storage capacity. Another area of research is the development of CO<sub>2</sub> injection techniques that achieve broad dispersion of CO<sub>2</sub> throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock.

Several of the major unresolved issues with respect to CO<sub>2</sub> sequestration pertain to the legal framework for closing and remediating geologic 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.<sup>2</sup> Until the financial responsibility issues are defined and codified by the Federal government, companies and most likely states will not undertake commercial geologic CO<sub>2</sub> sequestration activities beyond those states that already have regulations for EOR. There are several types of geologic formations in which CO<sub>2</sub> can be stored, and each has different opportunities and challenges as briefly described below:

#### **3.2.1.1.1 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 CO<sub>2</sub> and makes these formations excellent sequestration opportunities.

As a value-added benefit, CO<sub>2</sub> injected into a depleting oil reservoir can enable recovery of additional oil and gas. When injected into a depleted oil bearing formation, the CO<sub>2</sub> 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 CO<sub>2</sub> 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.<sup>3</sup> There are no known oil or gas reservoirs providing CO<sub>2</sub> 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.<sup>4</sup> These oil fields provide a sequestration opportunity that is considered technically feasible for the HEC.

#### **3.2.1.1.2 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 CO<sub>2</sub>, which preferentially adsorbs onto the surface of the coal, releasing the methane. Two or three molecules of CO<sub>2</sub> are adsorbed for each molecule of methane released, thereby providing an excellent storage sink for CO<sub>2</sub>. Like depleting oil reservoirs, unmineable coal beds are a good early opportunity for CO<sub>2</sub> storage.

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<sup>2</sup> 40 CFR Parts 144 and 146: Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO<sub>2</sub>G4) Geologic Sequestration (GS) Wells.

<sup>3</sup> “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](http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/National%20Perspectives.pdf)

<sup>4</sup> *Ibid.* Page 69.

One potential barrier to injecting CO<sub>2</sub> into unmineable coal seams is swelling. When coal adsorbs CO<sub>2</sub>, it swells in volume. In an underground formation swelling can cause a sharp drop in permeability, which not only restricts the flow of CO<sub>2</sub> 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 CO<sub>2</sub> sequestration potential exists in unmineable coal seams identified by the RCSPs.<sup>5</sup> 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.<sup>6</sup> Although CO<sub>2</sub> sequestration in unmineable coal seams may be technically feasible, it is much less developed and proven relative to EOR. As such, CO<sub>2</sub> 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 any closer to HEC as the EOR sites.

#### **3.2.1.1.3 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 CO<sub>2</sub> storage capacity. The RCSPs estimate a range of 3,300 to 12,000 billion metric tons of sequestration potential in saline formations.<sup>7</sup> 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 CO<sub>2</sub>. Saline formations contain minerals that could react with injected CO<sub>2</sub> 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.<sup>8</sup> 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.<sup>9</sup> Although CO<sub>2</sub> sequestration in saline formations may be technically feasible, it is much less developed and proven in comparison to EOR. As such, CO<sub>2</sub> 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.

#### **3.2.1.1.4 Basalt formations**

Basalts are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> emissions. This CO<sub>2</sub>

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<sup>5</sup> Ibid. page 14.

<sup>6</sup> Ibid. page 63.

<sup>7</sup> Ibid. page 20.

<sup>8</sup> Ibid, page 15

<sup>9</sup> Ibid. page 63.

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.

### 3.2.1.2 Terrestrial Ecosystems

Terrestrial sequestration is the enhancement of CO<sub>2</sub> 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 CO<sub>2</sub> 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 10 to 19 million tons per year of CO<sub>2</sub>.

Carbon can be sequestered in terrestrial ecosystems by:<sup>10</sup>

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 CO<sub>2</sub>, so storing biomass is storing atmospheric carbon. Dry biomass is roughly 50% 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 CO<sub>2</sub> concentrations, while providing additional 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 CO<sub>2</sub> emissions be reduced in other ways to acceptable levels 50-100 years from now.

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<sup>10</sup> “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.

However, due to the undemonstrated cost and effectiveness of terrestrial ecosystem sequestration options for storing 10 to 18 million tons per year of CO<sub>2</sub> over the life of the HEC, this sequestration option is considered technically infeasible and will not be further evaluated as BACT.

### **3.3 Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options**

The only technically feasible strategy for mitigating CO<sub>2</sub> 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 CO<sub>2</sub> emission reduction of approximately 8.5 million tons per year.

### **3.4 Step 4 - Evaluate More Effective Control Options**

The exhaust stream from the CO<sub>2</sub> vent will be suitable for transporting by pipeline, with a purity of approximately 98 percent CO<sub>2</sub>, but will need to be dried and boosted in pressure from 900 pounds per square inch to 2000 pounds per square inch.<sup>11</sup> These requirements would increase the electrical load on the IGCC power plant by 267 megawatts (“MW”), which would significantly increase fuel and energy use and would increase air emissions by approximately 175 tons of PM-2.5, 86 tons of NO<sub>x</sub>, 50 tons of SO<sub>2</sub>, 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 CO<sub>2</sub> CCS is approximately \$43 per ton CO<sub>2</sub> sequestered.

It has been assumed for this analysis that the recovered CO<sub>2</sub> 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 \$10 to \$16 per metric tonne of CO<sub>2</sub> for EOR but does not include long term monitoring and maintenance costs.<sup>12</sup> Assuming the cost benefit of EOR, this reduces the avoided cost of CO<sub>2</sub> for CCS \$10 per ton, making the net levelized annual cost approximately \$33 per ton of CO<sub>2</sub>.

In RTP’s experience, there is no precedent for determining the costs that are reasonable for CO<sub>2</sub> 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 \$2/metric tonne of CO<sub>2</sub>, or approximately \$1.80 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

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<sup>11</sup> Compressing captured CO<sub>2</sub> to pipeline pressure (1,200–2,000 pounds per square inch (psi)) represents a large parasitic load. [http://www.netl.doe.gov/technologies/carbon\\_seq/core\\_rd/co2capture.html](http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html).

<sup>12</sup> *IPCC Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change. 2005. Page 345.

with the adverse energy and environmental impacts of CCS, this control option does not represent BACT.

### **3.5 Step 5 - Establish BACT**

Because no control option more effective than the baseline has been identified as BACT for CO<sub>2</sub> emissions from the acid gas removal process at the HEC, no emission limitation is appropriate. Appendix A presents the basis for the impacts analysis for the HEC combustion turbines and process heaters.

# Chapter 4. BACT for Combustion Turbines and Process Heaters

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## 4.1 Step 1 – Identify Control Options

There are two broad strategies for reducing CO<sub>2</sub> emissions from stationary combustion processes such as the combustion turbines and process heaters at the HEC. The first is to minimize the production of CO<sub>2</sub> through the use of low-carbon fuels and through aggressively energy-efficient design. As shown in Table 4.1-1, the use of gaseous fuels, such as natural gas and refinery gas, reduces the production of CO<sub>2</sub> during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly efficient operation requires less fuel for process heat, which directly impacts the amount of CO<sub>2</sub> produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce CO<sub>2</sub> production and the costs to recover it.

The second strategy for CO<sub>2</sub> emission reduction is CCS. Unlike the exhaust stream associated with the acid gas removal process, the inherent design of the the combustion turbines and process heaters at the HEC produce a dilute CO<sub>2</sub> stream that requires capture.

The CO<sub>2</sub> 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 CO<sub>2</sub> exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing CO<sub>2</sub> from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO<sub>2</sub> from the combustion exhaust gases. Because the air used for combustion contains nearly 80 percent nitrogen, the CO<sub>2</sub> concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

## 4.2 Step 2 – Eliminate Technically Infeasible Control Options

### 4.2.1 Low-Carbon Fuels

Numerous fuels are available for use at the HEC. Several of these fuels will be produced at the refinery as a result of the petroleum refining process. Historically, petroleum refineries have

burned wide range of fuels, including high-carbon fuels such as residual oil and petroleum coke, in sources such as boilers and process heaters. As Table 1.2-1 shows, combustion of refinery gas and natural gas yields 40 to 50 percent less CO<sub>2</sub> than does combustion of coal and petroleum coke and approximately 30 percent less CO<sub>2</sub> than does combustion of residual oil. Combustion of the syngas produced at the HEC IGCC power plant yields approximately 65 percent less CO<sub>2</sub> than does combustion of coal and petroleum coke and approximately 55 percent less CO<sub>2</sub> than does combustion of residual oil. Accordingly, the preferential burning of these low-carbon gaseous fuels to meet the refinery's energy needs is an extremely effective CO<sub>2</sub> control technique. This control technique is technically feasible for all process heaters and combustion turbines at the HEC and is an inherent part of the facility's design.

## **4.2.2 Energy Efficiency**

There are numerous strategies for achieving a highly energy-efficient design of a greenfield petroleum refinery. All identified strategies are technically feasible for application to the HEC and all are inherent in the design of the facility. These include the following.

### **4.2.2.1 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 CO<sub>2</sub> emissions is typically 10 to 15 percent. This heat recovery approach is commonly used 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 CO<sub>2</sub> emitted, it increases emissions of NO<sub>x</sub> 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 CO<sub>2</sub> that would be emitted firing additional natural gas or refinery fuel gas to make up the heat lost in the heater flue gas.

### **4.2.2.2 Use of Process Heat to Generate Steam**

One method that petroleum refiners use to be more energy efficient 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 CO<sub>2</sub> that would be emitted if natural gas or refinery fuel gas was used to generate this steam instead.

### **4.2.2.3 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.

#### 4.2.2.4 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 oxygen monitor in the heater stack and damper controls on the combustion air dampers. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only CO<sub>2</sub> emissions but also NO<sub>x</sub> emissions. All of the HEC process heaters and combustion turbines will be equipped with oxygen monitors as part of the continuous emission monitoring system.

#### 4.2.2.5 Cogeneration as a CO<sub>2</sub> Reduction Technique

Cogeneration is the simultaneous production of electric power and thermal energy from a single fuel. 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”), from which steam is made available for use in providing heat to refinery process units. The reduction in CO<sub>2</sub> emissions from employing cogeneration comes from the reduced fuel use at electric utility power plants; thus, the amount of CO<sub>2</sub> reduction is dependent upon the type of electric utility power generation displaced. Where coal-based generation is displaced, CO<sub>2</sub> reductions of 30 percent or more are achievable. 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 a 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.

### 4.2.3 Carbon Capture and Storage

#### 4.2.3.1 CO<sub>2</sub> Capture

There are two pre-combustion CO<sub>2</sub> capture techniques with the potential for use with combustion sources at the HEC: indirect use of oxygen and direct use of oxygen. The indirect approach involves partial combustion of a carbon-containing fuel (e.g., refinery gas, residual oil, or coke) with oxygen and steam to produce a synthesis gas (“syngas”) composed of carbon monoxide (CO) and hydrogen (H<sub>2</sub>). The CO is reacted with steam in a catalytic reactor, called a shift converter, to yield CO<sub>2</sub> and additional H<sub>2</sub>. The CO<sub>2</sub> is then separated, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be combusted in

boilers, furnaces, gas turbines, engines and fuel cells. This approach would work only with new equipment specifically designed to burn hydrogen because existing equipment would not be configured appropriately. The combustion of hydrogen as fuel in boilers, process heaters, and combustion turbines has not been demonstrated at the scale required for petroleum refineries and is considered technically infeasible.

The direct approach to pre-combustion CO<sub>2</sub> separation involves substituting oxygen for air during the combustion process. Because the heaters and combustion turbines at the HEC are designed to use air for combustion, the use of oxygen would require substantial redesign. No commercially proven equipment meeting these design requirements is available. Accordingly, CCS involving pre-combustion CO<sub>2</sub> separation and capture is technically infeasible.

Technical feasibility of post-combustion CO<sub>2</sub> capture technologies is addressed in the following paragraphs.

#### **4.2.3.1.1      *Chemical absorption.***

This is the most common method for CO<sub>2</sub> capture. Monoethanolamine (“MEA”) solvent has the advantage of fast reaction with CO<sub>2</sub> at low partial pressure. The primary concerns with MEA and other amine solvents are corrosion in the presence of O<sub>2</sub> and other impurities, high solvent degradation rates due to reactions with SO<sub>2</sub> and NO<sub>x</sub>, and the large amount of energy required for solvent regeneration. These difficulties can be overcome, and this capture method is technically feasible.

#### **4.2.3.1.2      *Physical absorption (e.g., Selexol®).***

These absorption processes, which are commonly used for CO<sub>2</sub> rejection from natural gas, operate at high pressure and low temperature. Use of physical absorption for CO<sub>2</sub> capture from combustion exhaust gas would entail a significant amount of gas compression capacity and a significant energy penalty. These difficulties can be overcome, and this capture method is technically feasible.

#### **4.2.3.1.3      *Calcium cycle separation.***

This is a quicklime-based capture method that yields limestone. When heated, the limestone releases CO<sub>2</sub>, producing quicklime again for recycling. Work is still required on sorbent stability after regeneration.

#### **4.2.3.1.4      *Cryogenic separation.***

This capture method is based on solidifying the CO<sub>2</sub> component of the exhaust stream by frosting it to separate it out. The low concentration of CO<sub>2</sub> in the exhaust gas from conventional air-based combustion processes, such as the process heaters and combustion turbines at the HEC, renders this technology infeasible for this application.

#### **4.2.3.1.5      *Membrane separation.***

This method is commonly used for CO<sub>2</sub> removal from natural gas at high pressure and high CO<sub>2</sub> concentration. Membrane technology is not fully developed for low CO<sub>2</sub> concentrations and gas flow at the scale required for the HEC.

#### 4.2.3.1.6 Adsorption.

This method involves feeding the exhaust gas through a bed of solid material with high surface areas, such as zeolites or activated carbon. These materials can preferentially adsorb CO<sub>2</sub> while allowing nitrogen and other gases to pass through. The fully saturated bed is regenerated by either pressure swing (low pressure), temperature swing (high temperature), or electric swing (low voltage) desorption. Adsorption would require either a high degree of compression or multiple separation steps to produce high CO<sub>2</sub> concentration from exhaust gas. This capture method is presumed for the purposes of this analysis to be technically feasible, but its capital and operating costs exceed those of available chemical absorption techniques, so adsorption will not be considered further.

#### 4.2.3.2 CO<sub>2</sub> Transportation and Storage

Compression, transportation, and storage of CO<sub>2</sub> from the combustion processes at the HEC are technically feasible, as discussed in Section 3.2 herein.

### 4.3 Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The use of low-carbon fuels and aggressively energy-efficient design to reduce CO<sub>2</sub> emissions from combustion turbines and process heaters is inherent in the design of the HEC and is considered the baseline condition.

The only technically feasible strategy for further controlling CO<sub>2</sub> emissions from the process heaters and combustion turbines at the HEC is CCS. For the purposes of this analysis, chemical absorption is assumed to represent the best capture option 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 and to result in a CO<sub>2</sub> emission reduction of approximately 8.0 million tons per year.

### 4.4 Step 4 - Evaluate More Effective Control Options

Using CCS to reduce CO<sub>2</sub> emissions from the process heaters and combustion turbines at the HEC will have substantial impacts on the facility in many respects, as discussed in detail below.

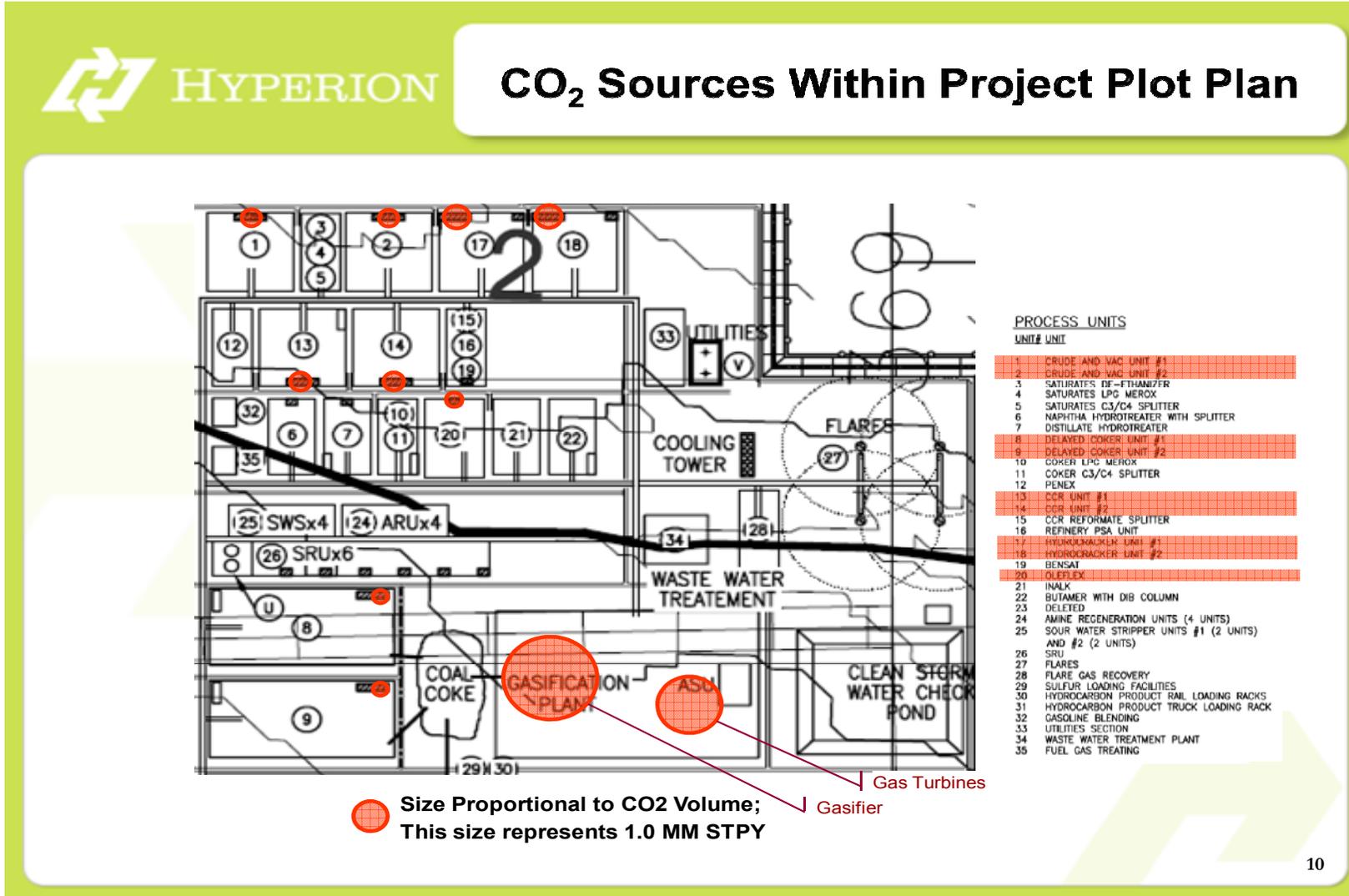
#### 4.4.1 Design Considerations

As shown in Table 1.2-2, emissions of CO<sub>2</sub> from the four combustion turbines and the thirty process heaters are approximately 9 million tons per year. This represents 50 percent of the CO<sub>2</sub> emissions from the HEC, but these combustion sources are scattered throughout the facility. The largest of these sources are the four equal-sized combustion turbines in the IGCC power plant. In order to capture the CO<sub>2</sub> from the combustion turbine exhaust, because these units will be in close proximity, their vents would be ducted together and CO<sub>2</sub> recovery would be accomplished using a single, large solvent scrubbing/regeneration system.

The refinery process heaters are much more numerous and spaced further apart than the turbines. As a result, multiple scrubbers will be installed as it is more economical to pump the solvent throughout the refinery than it is to duct all of the flue gases into a single scrubbing system. The CO<sub>2</sub>-rich solvent from the scrubbers is then pumped to a regeneration system for CO<sub>2</sub> removal and reuse. These systems will be collectively more costly than for the combustion turbine exhaust system due to the need for multiple scrubbers. Of the 30 heaters in the refinery, 26 can be combined into nine combined furnace stacks. These heaters are located in the Delayed Coking Units (2), Continuous Catalytic Reformers (2), the Crude and Vacuum Units (2), the Hydrocracking Units (2), and the Oleflex Unit (1). A scrubbing system would be located at each of these units for CO<sub>2</sub> capture. These scrubbing systems would control approximately 90 percent of the total CO<sub>2</sub> emissions from heaters. The four heaters that are not covered by the scrubbing systems in this analysis represent only two percent of the facility-wide CO<sub>2</sub> emissions from the HEC; these heaters are omitted from the analysis because they are less cost-effective to control than are the other heaters and including them would skew the overall cost-effectiveness analysis. The combined collection and control of the four combustion turbines and 26 process heaters represents approximately 7.4 million tons per year of CO<sub>2</sub> capture.

Figure 4.4-1 shows the HEC plot plan and the location of the nine process heater stacks where the scrubbing systems would be located. (This figure also shows the location of the CO<sub>2</sub> vents from the acid gas removal process as discussed in Chapter 3 herein.) It is assumed that MEA absorption systems will be used to scrub the CO<sub>2</sub> from the combustion turbine and large process heater flue gases. The MEA is regenerated with steam to produce a CO<sub>2</sub>-rich stream. The CO<sub>2</sub> 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.

FIGURE 4.4-1. HEC PLOT PLAN AND THE LOCATION OF THE NINE PROCESS HEATER STACKS AND CO<sub>2</sub> SCRUBBERS



#### **4.4.2 Impacts Analysis**

The use of CCS for the combustion sources at the HEC 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. The estimated 7.4 million tons per year of CO<sub>2</sub> captured from the combustion turbines and 26 process heaters would require the equivalent to 582 MW of electric power and steam generation capacity for capture, drying compression, and transport to a suitable EOR site. If all of the power generation is based on combined cycle combustion turbines firing natural gas, the increase fuel use and would increase air emissions by approximately 381 tons of PM-2.5, 188 tons of NO<sub>x</sub>, 109 tons of SO<sub>2</sub>, 115 tons of CO, and 29 tons of VOC per year. The estimated capital costs for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately \$900 million. The levelized annual cost, including operating cost, is estimated to be approximately \$500 million per year. The resulting avoided cost of CO<sub>2</sub> CCS is approximately \$101 per ton of CO<sub>2</sub> sequestered.

Assuming a \$10 per ton cost benefit of EOR, the avoided cost of CO<sub>2</sub> for CCS becomes \$91 per ton of CO<sub>2</sub> sequestered from the combustion turbines and 26 process heaters.

### **4.5 Step 5 - Establish BACT**

Because no control option more effective than the baseline has been identified as BACT for CO<sub>2</sub> emissions from the combustion turbines and process heaters at the HEC, no emission limitations are appropriate. Appendix B presents the basis for the impacts analysis for the HEC combustion turbines and process heaters.

# APPENDIX A – IMPACTS ANALYSIS FOR HEC CO2 VENT

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PARAMETER	<u>GASIFICATION CO2 VENT</u>	
	<u>BASELINE - No Compression, Transport, Sequestration</u>	<u>Compression+Transport +Sequestration</u>
<b>Environmental Impacts:</b>		
CO2 Emitted, TPY	8,500,000	0.0
CO2 Incremental % Control	Baseline	100%
CO2 Reduced, TPY	Baseline	8,500,000
CO2 from Compression, TPY	Baseline	952,669
Net CO2 Reduced, TPY	Baseline	7,500,000
Increase in NOx, TPY	Baseline	79
Increase in SO2, TPY	Baseline	44
Increase in CO, TPY	Baseline	46
Increase in VOC, TPY	Baseline	12
Increase in PM2.5, TPY	Baseline	155
<b>Energy Impacts:</b>		
Additonal Power Generation, MW	Baseline	267
NG Use MMSCFY	Baseline	15,567
<b>Economic Impacts:</b>		
Total Capital Cost	Baseline	\$649,800,000
Total Annual Cost	Baseline	\$288,700,000
CO2 Capture Cost Effectiveness	Baseline	\$38
CO2 Transport Cost Effectiveness	Baseline	\$5
CO2 EOR Cost Effectiveness	Baseline	-\$10
Total CO2 CCS Cost Effectiveness	Baseline	\$33

<b>HEC ESTIMATED COST OF CO2 CAPTURE BASED ON IPPC REPORT TABLE 3.15 - Gasification CO2 Vent</b>							
<u>Parameter</u>	<u>Units</u>	<u>IGCC</u> <u>low</u>	<u>IGCC</u> <u>high</u>	<u>Parameter</u>	<u>Units</u>	<u>HEC</u>	<u>Comments</u>
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMB/hr steam equivalent MW (see below)
Emission Rate wo Capture	kgCO2/MWh	628	846	Emission Rate wo Capture	ton/year	8,541,956	From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	81	91	Percent Reduction	%	100	Post Rectisol
Emission Rate w Capture	kgCO2/MWh	65	152	Emission Rate w Capture	ton/year	0	
				CO2 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 CO2 w Capture	ton/year	952,669	120 lb CO2/MMBtu for NG
Total Capital wo Capture	US\$/kw	1169	1565	Total Capital wo 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 captial
				Total Annual Costs	Millions \$/yr	\$289	
Cost of CO2 Captured	US\$/tonne CO2	11	32	Cost of CO2 Captured	US\$/st CO2	\$34	
Cost of CO2 avoided	US\$/tonne CO2	13	37	Cost of CO2 avoided	US\$/st CO2	\$38	
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					

# APPENDIX B – IMPACTS ANALYSIS FOR HEC COMBUSTION TURBINES AND PROCESS HEATERS

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PARAMETER	<b>COMBUSTION TURBINES &amp; PROCESS HEATERS</b>	
	<b><u>BASELINE - No CCS</u></b>	<b><u>With CCS</u></b>
<b>Environmental Impacts:</b>		
CO2 Emitted, TPY	8,200,000	800,000
CO2 Incremental % Control	Baseline	90%
CO2 Reduced, TPY	Baseline	7,400,000
CO2 from Compression, TPY	Baseline	1,930,000
Net CO2 Reduced, TPY	Baseline	5,300,000
Increase in NOx, TPY	Baseline	188
Increase in SO2, TPY	Baseline	109
Increase in CO, TPY	Baseline	115
Increase in VOC, TPY	Baseline	29
Increase in PM2.5, TPY	Baseline	381
<b>Energy Impacts:</b>		
Additonal Power Generation, MW	Baseline	582
NG Use MMSCFY		33,991
<b>Economic Impacts:</b>		
Total Capital Cost	Baseline	\$904,100,000
Total Annual Cost	Baseline	\$527,500,000
CO2 Capture Cost Effectiveness	Baseline	\$100
CO2 Transport Cost Effectiveness	Baseline	\$5
CO2 EOR Cost Effectiveness	Baseline	-\$10
Total CO2 CCS Cost Effectiveness	Baseline	\$95

<b>HEC ESTIMATED COST OF CO2 CAPTURE BASED ON IPPC REPORT TABLE 3.15 – Combustion Turbines (4)</b>							
<u>Parameter</u>	<u>Units</u>	<u>IGCC</u> <u>low</u>	<u>IGCC</u> <u>high</u>	<u>Parameter</u>	<u>Units</u>	<u>HEC</u>	<u>Comments</u>
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMlb/hr steam equivalent MW (see below)
Emission Rate wo Capture	kgCO2/MWh	344	379	Emission Rate wo Capture	ton/year	3,986,530	From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	83	88	Percent Reduction	%	85.5	Average of 83 & 88 % MWh
Emission Rate w Capture	kgCO2/MWh	40	66	Emission Rate w Capture	ton/year	578,047	14.5% not captured
				CO2 Captured	ton/year	3,408,484	
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 CO2 w Capture	ton/year	806,105	120 lb CO2/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 captial
				Total Annual Costs	Millions \$/yr	\$262	
Cost of CO2 Captured	US\$/tonne CO2	33	57	Cost of CO2 Captured	US\$/st CO2	\$77	
Cost of CO2 avoided	US\$/tonne CO2	37	74	Cost of CO2 avoided	US\$/st CO2	\$101	
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					

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

<u>Parameters</u>	<u>Units</u>	<u>Grangemouth</u>	<u>HEC</u>	<u>Comments</u>
Refinery Size - CO2 Emitted	Millions st/yr	2.4	4.2	HEC From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	93%	93%	assumed
CO2 Captured	Millions st/yr	2.2	3.9	
Capture Energy Required	MW fired	396	710	HEC ratioed from reference
Capture Energy Required	MMBtu/hr	1,351	2,424	HEC ratioed from reference; equivalent to 357 MW
NG Use for Incremental MW	MM SCFY	11,604	20,819	based on 1020 Btu/scf for NG
Capture Energy CO2	Millions st/yr	0.7	1.3	
Percent Reduction	%	93%	93%	
CO2 Captured	Millions st/yr	0.66	1.18	
Total Captial	Millions US\$	\$149	\$267	HEC ratioed from reference
Annualized Capital Costs	Millions US\$/yr	\$22	\$40	15% of capital costs
Annualized NG Costs @ \$10	Millions US\$/yr	\$118	\$212	\$10 per MMBtu for NG
Annual O&M Costs	Millions US\$/yr	\$7	\$13	5% of total captial
Total Annual Costs	Millions US\$/yr	\$148	\$266	
Cost of CO2 Captured	US\$/st CO2	\$67	\$67	
Cost of CO2 Avoided	US\$/st CO2	\$99	\$99	
REFERENCE: "A Study of Very Large Scale Post Combustion CO2 Capture At a Refining & Petrochemical Complex", Grangemouth, , UK.				

**FACT SHEET**  
**FINAL REVISIONS TO THE NATIONAL AMBIENT AIR QUALITY STANDARDS**  
**FOR NITROGEN DIOXIDE**

**SUMMARY OF ACTION**

- On January 22, 2010, EPA strengthened the health-based National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO<sub>2</sub>). The new standard will protect public health, including the health of sensitive populations – people with asthma, children and the elderly.
- EPA is setting a new 1-hour NO<sub>2</sub> standard at the level of 100 parts per billion (ppb). This level defines the maximum allowable concentration anywhere in an area. It will protect against adverse health effects associated with short-term exposure to NO<sub>2</sub>, including respiratory effects that can result in admission to a hospital.
- In addition to establishing an averaging time and level, EPA also is setting a new “form” for the standard. The form is the air quality statistic used to determine if an area meets the standard. The form for the 1-hour NO<sub>2</sub> standard, is the 3-year average of the 98<sup>th</sup> percentile of the annual distribution of daily maximum 1-hour average concentrations.
- EPA also is retaining, with no change, the current annual average NO<sub>2</sub> standard of 53 ppb.
- This suite of standards will protect public health by limiting people’s exposures to short-term peak concentrations of NO<sub>2</sub> – which primarily occur near major roads – and by limiting community-wide NO<sub>2</sub> concentrations to levels below those that have been linked to respiratory-related emergency department visits and hospital admissions in the United States.
- To determine compliance with the new standard, EPA is establishing new ambient air monitoring and reporting requirements for NO<sub>2</sub>.
  - In urban areas, monitors are required near major roads as well as in other locations where maximum concentrations are expected.
  - Additional monitors are required in large urban areas to measure the highest concentrations of NO<sub>2</sub> that occur more broadly across communities.
  - Working with the states, EPA will site a subset of monitors in locations to help protect communities that are susceptible and vulnerable to NO<sub>2</sub>-related health effects.
- The addition of a new 1-hour NO<sub>2</sub> standard and changes to the NO<sub>2</sub> monitoring network are consistent with the recommendations of the majority of the Clean Air Scientific Advisory Committee (CASAC). CASAC provides independent advice to the EPA Administrator on the relevant scientific and technical information and on the standards.
- These changes will not affect the secondary NO<sub>2</sub> standard, set to protect public welfare. EPA is considering the need for changes to the secondary standard under a separate review.

## **NO<sub>2</sub> AND PUBLIC HEALTH**

- Current scientific evidence links short-term NO<sub>2</sub> exposures, ranging from 30 minutes to 24 hours, with an array of adverse respiratory effects including increased asthma symptoms, more difficulty controlling asthma, and an increase in respiratory illnesses and symptoms.
- Studies also show a connection between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.
- NO<sub>2</sub> concentrations near major roads are appreciably higher than those measured at monitors in the current network. Concentrations in heavy traffic or on freeways can be twice as high as levels measured in residential areas or near smaller roads. Monitoring studies indicate that near-road (within about 50 meters) concentrations of NO<sub>2</sub> can be 30 to 100 percent higher than concentrations away from major roads.
- EPA's NAAQS for NO<sub>2</sub> is designed to protect against exposure to the entire group of nitrogen oxides (NO<sub>x</sub>). NO<sub>2</sub> is the component of greatest concern and is used as the indicator for the larger group of NO<sub>x</sub>. The sum of nitric oxide (NO) and NO<sub>2</sub> is commonly called NO<sub>x</sub>. Other nitrogen oxides include nitrous acid and nitric acid.
- Emissions that lead to the formation of NO<sub>2</sub> generally also lead to the formation of other NO<sub>x</sub>. Control measures that reduce NO<sub>2</sub> can generally be expected to reduce population exposures to all gaseous NO<sub>x</sub>. This may have the co-benefit of reducing the formation of ozone and fine particles both of which pose significant public health threats.
  - NO<sub>x</sub> react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.
  - NO<sub>x</sub> react with volatile organic compounds to form ozone. Children, the elderly, people with lung diseases such as asthma, and people who work or exercise outside are at risk for adverse health effects from ozone. These effects include reduced lung function and increased respiratory symptoms, more respiratory-related emergency department visits and hospital admissions, and increased risk of premature death from heart or lung disease. EPA's NAAQS for ozone are designed to provide protection against these health effects.

## **REVISING THE NO<sub>2</sub> MONITORING NETWORK**

- EPA is setting new requirements for the placement of new NO<sub>2</sub> monitors in urban areas. These include:
  - Near Road Monitoring**
    - At least one monitor must be located near a major road in any urban area with a population greater than or equal to 500,000 people. A second monitor is required

near another major road in areas with either:

- (1) population greater than or equal to 2.5 million people, or
- (2) one or more road segment with an annual average daily traffic (AADT) count greater than or equal to 250,000 vehicles.

These NO<sub>2</sub> monitors must be placed near those road segments ranked with the highest traffic levels by AADT, with consideration given to fleet mix, congestion patterns, terrain, geographic location, and meteorology in identifying locations where the peak concentrations of NO<sub>2</sub> are expected to occur. Monitors must be placed no more than 50 meters (about 164 feet) away from the edge of the nearest traffic lane.

- EPA estimates that the new NO<sub>2</sub> monitoring requirements will result in a network of approximately 126 NO<sub>2</sub> monitoring sites near major roads in 102 urban areas.

#### **Community Wide Monitoring**

- A minimum of one monitor must be placed in any urban area with a population greater than or equal to 1 million people to assess community-wide concentrations.
- An additional 53 monitoring sites will be required to assess community-wide levels in urban areas.
- Some NO<sub>2</sub> monitors already in operation may meet the community-wide monitor siting requirements.

#### **Monitoring to Protect Susceptible and Vulnerable Populations**

- Working with the states, EPA Regional Administrators will site at least 40 additional NO<sub>2</sub> monitors to help protect communities that are susceptible and vulnerable to NO<sub>2</sub>-related health effects.
- All new NO<sub>2</sub> monitors must begin operating no later than January 1, 2013.
  - EPA Regional Administrators have the authority to require additional monitoring in certain circumstances, such as in areas impacted by major industrial point sources or a combination of sources where there is an indication that the standards may be exceeded. The Regional Administrators also have the authority to require additional near-road monitoring in urban areas where multiple peak concentration areas may be caused by a variety of mobile source factors including fleet mix, traffic congestion patterns, or terrain.

### **IMPLEMENTING THE NEW NO<sub>2</sub> STANDARD**

- In this final rule, EPA is outlining the Clean Air Act requirements that states must address to implement the new NO<sub>2</sub> air quality standard.
- The new standard must be taken into account when permitting new or modified major sources of NO<sub>x</sub> emissions such as fossil-fuel fired power plants, boilers, and a variety of other manufacturing operations.
- EPA expects to identify or “designate” areas as attaining or not attaining the new standard by January 2012, within two years of establishing the new NO<sub>2</sub> standard. These designations

will be based on the existing community-wide monitoring network. Areas with monitors recording violations of the new standards will be designated “nonattainment.” EPA anticipates designating all other areas of the country “unclassifiable” to reflect the fact that there is insufficient data available to determine if those areas are meeting the revised NAAQS.

- Once the expanded network of NO<sub>2</sub> monitors is fully deployed and three years of air quality data have been collected, EPA intends to redesignate areas in 2016 or 2017, as appropriate, based on the air quality data from the new monitoring network.

## **BACKGROUND**

- The Clean Air Act requires EPA to set national ambient air quality standards for pollutants considered harmful to public health and the environment. National standards exist for six pollutants: nitrogen dioxide, ozone, particulate matter, carbon monoxide, sulfur dioxide, and lead.
- For each of these pollutants, the Clean Air Act requires EPA to set the health-based or “primary” standards at a level judged to be “requisite to protect the public health with an adequate margin of safety” and establish secondary standards that are “requisite” to protect public welfare from “any known or anticipated adverse effects associated with the pollutant in the ambient air” including effects on vegetation, soils, water, wildlife, buildings and national monuments, and visibility. EPA is considering the need for changes to the secondary NO<sub>2</sub> standard under a separate review.
- The law also requires EPA to review the standards and their scientific basis every five years to determine whether revisions are appropriate.
- Nitrogen dioxide is one of a group of highly reactive gasses known as “oxides of nitrogen.” NO<sub>2</sub> forms quickly from emissions from cars, trucks and buses, power plants, and off-road equipment. In addition to contributing to the formation of ground-level ozone and fine particle pollution, NO<sub>2</sub> is linked with a number of adverse effects on the respiratory system.
- EPA first established standards for NO<sub>2</sub> in 1971, setting both a primary standard (to protect health) and a secondary standard (to protect the public welfare) at 53 ppb, averaged annually. Prior to the current review, the Agency reviewed the standards twice since 1971, but chose not to revise the standards at the conclusion of each review.
- All areas presently meet the 1971 NO<sub>2</sub> NAAQS, with annual NO<sub>2</sub> concentrations measured at community-wide monitors well below the level of the standard (53 ppb). Annual average ambient NO<sub>2</sub> concentrations, as measured at community-wide monitors, have decreased by more than 40 percent since 1980. Currently, the annual average NO<sub>2</sub> concentrations range from approximately 10-20 ppb.
- EPA expects NO<sub>2</sub> concentrations to continue decreasing as a number of mobile source regulations take effect. Tier 2 standards for light-duty vehicles began phasing in during 2004, and new NO<sub>x</sub> standards for heavy-duty engines are phasing in between 2007 and 2010

model years. Current air quality monitoring data reflect only a few years of vehicles entering the fleet that meet these stricter NO<sub>x</sub> tailpipe standards.

## **FOR MORE INFORMATION**

- To download a copy of the final rule, go to EPA's Web site at: <http://www.epa.gov/air/nitrogenoxides>.
- This final rule and other background information are also available either electronically at <http://www.regulations.gov>, EPA's electronic public docket and comment system, or in hardcopy at the EPA Docket Center's Public Reading Room.
- The Public Reading Room is located in the EPA Headquarters, Room Number 3334 in the EPA West Building, located at 1301 Constitution Avenue, NW, Washington, DC. Hours of operation are 8:30 a.m. to 4:30 p.m. eastern standard time, Monday through Friday, excluding Federal holidays.
- Visitors are required to show photographic identification, pass through a metal detector, and sign the EPA visitor log. All visitor materials will be processed through an X-ray machine as well. Visitors will be provided a badge that must be visible at all times.
- Materials for this action can be accessed using Docket ID No. EPA-HQ-OAR-2006-0922.

# North Slope Borough

## OFFICE OF THE MAYOR

P.O. Box 69  
Barrow, Alaska 99723  
Phone: 907 852-2611 or 0200  
Fax: 907 852-0337 or 2595  
email: [edward.itta@north-slope.org](mailto:edward.itta@north-slope.org)



*Edward S. Itta, Mayor*

February 24, 2010

### **Via Electronic Mail**

**[skadowski.suzanne@epa.gov](mailto:skadowski.suzanne@epa.gov)**

Suzanne Skadowski  
Community Involvement Coordinator  
Environmental Protection Agency, Region 10  
(206) 553-6689

**Re: Shell Gulf of Mexico/Shell Offshore Inc.'s Application for a Camden Bay Clean Air Act Permit.**

Dear Ms. Skadowski:

The Environmental Protection Agency (EPA) has solicited comments on a proposed Clean Air Act Permit for Shell Gulf of Mexico/Shell Offshore Inc.'s (Shell) Camden Bay Exploration Plan (hereafter referred to as the "Camden Bay permit"). The North Slope Borough (NSB) is committed to the health and welfare of our residents, who are rightfully concerned about potential impacts associated with offshore oil and gas exploration and development. These impacts may be direct, indirect or cumulative in nature and relate to the quality of the natural environment upon which our residents rely.

We note that EPA has only allowed 30 days for public comment (from February 17, 2009 until March 22, 2010) on the proposed Camden Bay permit. This timeframe is inconsistent with 40 day comment period for the recently re-proposed permit for Shell's Chukchi Exploration Plan (the Chukchi Permit), which opened on January 8, 2010 and closed on February 17, 2010. Given the highly technical and distinct nature of both actions, an equal period of comment time to facilitate meaningful review and comment is thus appropriate.

The 30-day limitation is particularly problematic in that the administrative record underlying the permit is not yet available for review. This lack of information makes an already difficult technical review impossible and prevents us from meaningfully responding to the proposed action. The Camden Bay permit is subject to different statutory and regulatory guidelines than the Chukchi permit, as the proposed exploration is within 25 miles of the coast of Alaska. This exacerbates the difficulty in achieving consistent and informed review.

In light of the current unavailability of the administrative record, the different statutory and regulatory guidelines underlying the proposed action and, perhaps most importantly, the much closer proximity of the proposed Camden Bay exploration activity to the coastal district and communities of the North Slope, we request a minimum extension of **15 days** to review the proposed permit. In reviewing this request, we ask that EPA be guided by the principles of Environmental Justice found in Executive Order 12898 and take into account our interest in being meaningfully involved in this decision-making process.

In addition to this request, we ask that EPA make available as soon as possible the administrative record underlying the Camden Bay proposed permit to facilitate review of the action.

Thank you for your consideration of this request. If you have any questions, feel free to contact me.

Sincerely,

 *Acting Mayor*  
2/24/10  
Edward S. Itta  
Mayor

Cc: Dan Forster, Director, NSB Planning  
Taqulik Hepa, Director, NSB Wildlife  
Karla Kolash, Special Assistant, NSB Mayor  
Andy Mack, Special Assistant, NSB Mayor  
Bessie O'Rourke, Borough Attorney  
Tanya Sanerib, Crag Law



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
REGION 10  
1200 Sixth Avenue, Suite 900  
Seattle, Washington 98101-3140

Reply To  
Attn Of: AWT-107

March 1, 2010

Edward S. Itta, Mayor  
North Slope Borough  
P.O. Box 69  
Barrow, Alaska 99723

Re: Proposed Air Permit to Shell Offshore Inc. for oil and gas exploration on the Beaufort Sea outer continental shelf – Request to Extend the Public Comment Period

Dear Mayor Itta:

Thank you for your February 24, 2010 letter requesting that the U.S. Environmental Protection Agency (EPA) extend the public comment period an additional 15 days on our preliminary decision to issue an air quality permit to Shell Offshore Inc. (Shell) for its Beaufort Sea Exploration Program. Your request is based on the fact that the proposed Beaufort permit is distinct from and subject to different statutory and regulatory guidelines than the proposed permit for Shell's Chukchi Sea Exploration Program, adding difficulty to your technical review. In addition, your letter requests a review of the administrative record for the proposed permit, and an extension of the comment period would facilitate this review. The published comment period for this proposed permit began on February 17, 2010 and is scheduled to close on March 22, 2010.

EPA is denying your request to extend the public comment period. We understand and appreciate your concerns and the points you raise. While we acknowledge that there are differences between Shell's two proposed permits for the Beaufort Sea and the Chukchi Sea, there are also substantial parts that are the same since they both cover the same drilling vessel operating in a similar manner, with similar controls on that equipment. We have carefully evaluated your concerns and the competing interests which we must balance, and we believe it is in the overall best interest to retain the existing comment period. The comment period will close as scheduled on March 22, 2010. Written comments must be postmarked no later than March 22, 2010. We encourage all interested people to participate in the permit decision making process during the comment period. We will carefully consider all comments submitted during the comment period, before we make a final decision on the permit.

Per your request, enclosed is the administrative record for the proposed permit on CD.

I welcome the opportunity to continue working with residents throughout the North Slope Borough to continue improving our public involvement process to reflect the local communities' needs and I look forward to working with you in this regard.

Sincerely,

/s/

Rick Albright, Director  
Office of Air, Waste and Toxics

Enclosures

Exhibit 38  
AEWC & ICAS

Cc: (with enclosures)

Tanya Sanerib, Crag Law

Cc: (without enclosures)

Dan Forster, Director, NSB Planning

Taqulik Hepa, Director, NSB Wildlife

Karla Kolash, Special Assistant, NSB Mayor

Andy Mack, Special Assistant, NSB Mayor

Bessie O'Rourke, NSB Attorney

Jonny Jemming, Assistant NSB Attorney

**Subject:** FW: Air News Release (Region 10): EPA ISSUES AIR PERMIT TO SHELL OFFSHORE, INC., FOR DRILLING EXPLORATION IN ALASKA'S BEAUFORT SEA  
**From:** "Jonathan Jemming" <Jonathan.Jemming@north-slope.org>  
**Date:** Mon, 12 Apr 2010 08:45:15 -0800  
**To:** <tanya@crag.org>

-----Original Message-----

From: U.S. EPA [<mailto:usaepa@govdelivery.com>]

Sent: Mon 4/12/2010 7:28 AM

To: Jonathan Jemming

Subject: Air News Release (Region 10): EPA ISSUES AIR PERMIT TO SHELL OFFSHORE, INC., FOR DRILLING EXPLORATION IN ALASKA'S BEAUFORT SEA

EPA ISSUES AIR PERMIT TO SHELL OFFSHORE, INC., FOR DRILLING EXPLORATION IN ALASKA'S BEAUFORT SEA

Contact: Janis Hastings, EPA/Seattle, 206-553-1582, <mailto:hastings.janis@epa.gov> [hastings.janis@epa.gov](mailto:hastings.janis@epa.gov), Tony Brown, EPA/Seattle 206-553-1203, <mailto:brown.anthony@epa.gov> [brown.anthony@epa.gov](mailto:brown.anthony@epa.gov)

(SEATTLE - April 9, 2010) Shell Offshore, Inc. (Shell) has received a "Prevention of Significant Deterioration" (PSD) air quality permit from the U.S. Environmental Protection Agency. This permit will regulate air emissions from Shell's Frontier Discoverer drillship and its support vessels during exploratory oil and gas drilling on the outer continental shelf (OCS) above the Arctic Circle in Alaska's Beaufort Sea. This permit, similar to one issued last week for the Chukchi, covers drilling-related air emissions from July to December each year.

Rick Albright, Director of EPA's Air, Waste & Toxics office in Seattle, said today's permit announcement reflects the Administration's goal to explore options for increasing domestic oil production in a way that protects the environment.

"This permit ensures that exploration and drilling will occur in a way that protects air quality," said Albright. "We've listened closely to the Arctic communities of Kaktovik, Nuiqsut and Barrow in our effort to craft a permit that is both effective and enforceable."

Air emissions from the Frontier Discoverer's support fleet of two icebreaker ships and a supply ship will be limited by the permit. Also covered are emissions from the Frontier Discoverer's oil spill response fleet. All the engines, generators and an incinerator on the Frontier Discoverer, are covered by the permit.

Because the drillship operations are considered a "major" source under EPA regulations, the permit must ensure that the operations meet the requirements of the Prevention of Significant Deterioration (PSD) program in addition to the requirements of the OCS regulations.

Approval of the PSD permit was based in part on installation of pollution reduction controls in order to implement Best Available Control Technology (BACT) and in order to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and PSD increment. BACT applies only to emission sources on board the Discoverer,

In addition to BACT on the Discoverer, this permit requires Shell to reduce air emissions by utilizing Selective Catalytic Reduction on one of the icebreakers, Catalytic Diesel Particulate Filter on the Nanuq and Ultra Low Sulfur Diesel on all vessels that comprise the project.

EPA proposed the permit for public comment on February 17, 2010. EPA then conducted informational meetings and public hearings in Kaktovik, Nuiqsut and Barrow on March 16, 17, & 18, 2010.

Petitions for review must be received by the EAB no later than May 12, 2010

For more about EPA's work to protect air quality, go to:

<http://yosemite.epa.gov/R10/AIRPAGE.NSF/webpage/Air+Quality>  
<http://yosemite.epa.gov/R10/AIRPAGE.NSF/webpage/Air+Quality>

For electronic documents related to the Shell (Beaufort Sea) Permit, go to:

<http://yosemite.epa.gov/R10/AIRPAGE.NSF/permits/beaufortap>  
<http://yosemite.epa.gov/R10/AIRPAGE.NSF/permits/beaufortap>

Note: If the link above doesn't work, please copy and paste the URL into a browser.

<http://yosemite.epa.gov/opa/admpress.nsf/Press%20Releases%20From%20Region%2010!OpenView> View all Region 10 News Releases

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**SHELL OFFSHORE INC.**

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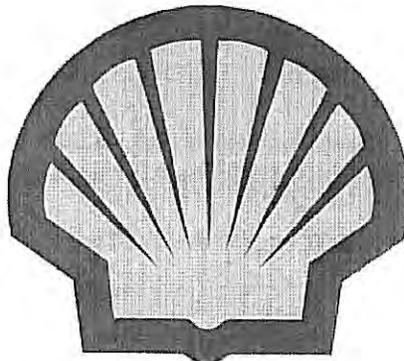
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**BEAUFORT SEA  
REGIONAL EXPLORATION  
OIL DISCHARGE PREVENTION  
AND  
CONTINGENCY PLAN**

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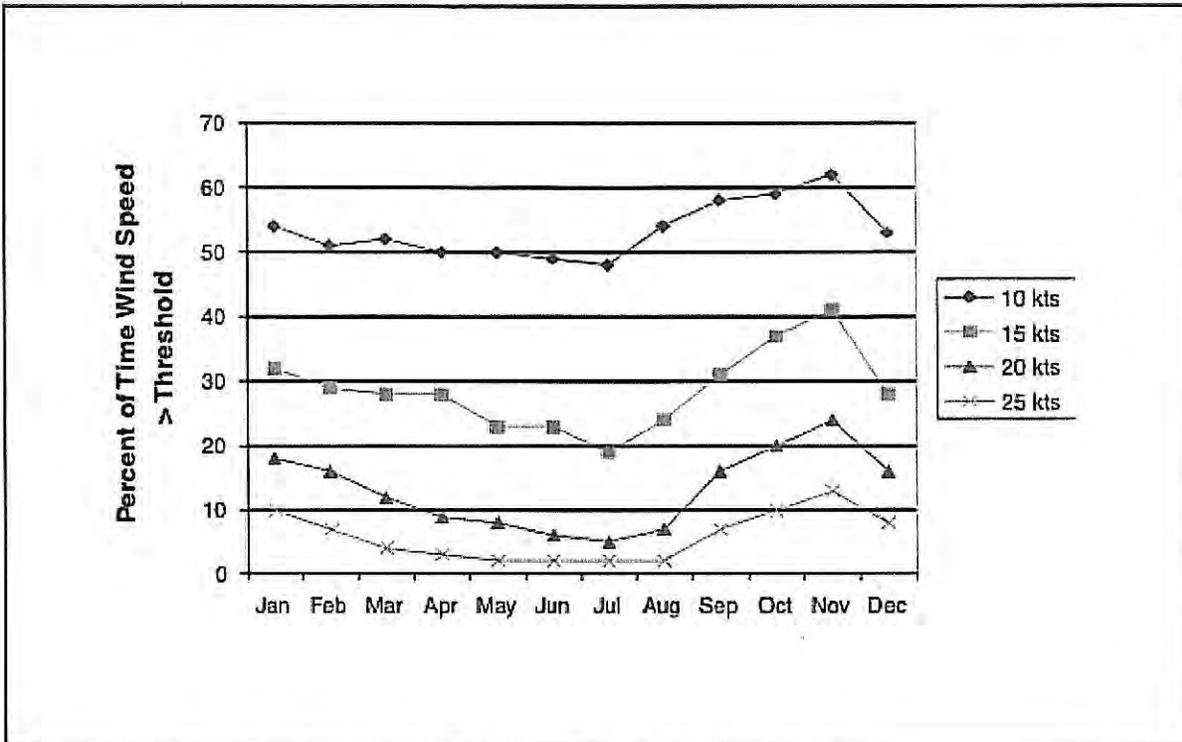
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**SHELL OFFSHORE INC.  
ANCHORAGE, ALASKA**



**SEPTEMBER 2007**

**FIGURE 3-3-3-4  
MONTHLY WIND SPEED EXCEEDANCE**



VAUDREY (2000) BASED ON LONG-TERM DATA FOR THE PRUDHOE BAY AREA

states during the period of maximum open water (mid-August to mid-October) can be estimated from this standard relationship. For example a moderate breeze of 11 to 16 knots (Force 4) will result in a wave height of 3.5 to 5 feet, a condition which would be exceeded approximately 30 percent of the time in September (Figure 3-34), the month with the maximum extent of open water off the Alaskan Beaufort Sea coast.

In the event that a storm surge occurs, critical drilling operations would be curtailed and continuous monitoring of the weather forecast would ensue. For specific limitations on response equipment due to sea states, see *ACS Technical Manual, Tactic L-7*.

**3.4.3 In Situ Burning Response Measures in Ice**

**Introduction**

One of the most important factors that influence drilling activities is the movement and amount of sea ice in the Beaufort Sea. Sea ice can pose a significant challenge for spill response; however, experience has shown that low temperatures and ice can often enhance spill response and reduce environmental impacts. For example:

- Low air and water temperatures often result in greater oil equilibrium thicknesses, thereby reducing spreading rates and areas of coverage. These reductions greatly reduce the potential for impact with natural resources while providing the potential for much higher oil encounter rates for mechanical recovery and burning operations.

- Evaporation rates are reduced, leaving the lighter and more volatile components in the oil longer, thereby enhancing the ease with which the oil could be ignited.
- The wind and sea conditions in the Beaufort Sea are considerably less dynamic than most open-ocean environments; and the presence of ice can actually dampen wave action and limit the fetch over which winds might otherwise create large waves.
- While ice, even in low concentrations, can preclude the effective use of oil containment boom, responders may still operate with short boom extensions and skimmers to maneuver among ice pieces and intercept oil.
- When ice concentrations preclude the use of any boom, the ice will often serve as a natural barrier to the spread of oil and help concentrate the oil for pocket-recovery operations with stationary skimmers. The natural containment of oil against ice will often result in thicknesses that could significantly enhance the efficient removal of oil with burning.
- When high ice concentrations (very close pack) and/or continuous stable ice conditions prevail, any spilled oil (especially from a subsea blowout) will likely become immobilized and encapsulated within the ice and, therefore, isolated from any contact with airborne or waterborne resources.
- Oil locked up and captured within the ice will be preserved physically and chemically so that its unweathered state upon release (deliberately exposed, or naturally released during break-up) will support combustion.

In addition to the above environmental factors, there are other spill source considerations that should be recognized as because they influence the full potential for elimination of spilled oil with burning:

- The spill scenarios associated with Shell's operations in the Beaufort Sea involve the release of oil and gas from a subsea blowout (in contrast to an above-water release such as from a fixed drilling structure). Oil would therefore be released to a relatively small area on the water with initial slicks with widths of typically a few hundred meters or less. Even with the gas-induced flow of oil and water toward the surface and the resulting radial spread of oil outward from the source, the initial area of involvement will be localized and relatively easy to contain and/or deflect with booms.
- Because of the likely release of large quantities of natural gas and vapors from the surfacing oil, it is likely that early ignition of that gas would be desirable as soon as the ~~drillshiping-rig~~ is moved off location. The vapor cloud could be readily ignited using standard ignition procedures, thereby eliminating the accidental ignition of the source when vessels are in close proximity. The early ignition of the source would not only be prudent for safety reasons, it is possible that significant quantities of oil could be eliminated through combustion at or near the source.
- With or without ignition of the blowout, prevailing atmospheric conditions in the Beaufort Sea will support safe operating conditions at or beyond a few hundred meters downwind of the source.

To summarize key points: the nature of oil released to the surface; the oil's limited spread due to reduced temperatures (and possible ice); and the potential for responders to access the oil before it moves far from the source and begins to weather, all enhance the potential for successful recovery and/or burning operations.

### **Key Combustion Processes**

The following discussion summarizes the current state of understanding the scientific principles and physical processes involved with in situ burning of oil on water and ice.

For an oil slick on water or ice to become ignited, the oil must be thick enough to insulate itself from the water beneath it. The igniter can heat the surface of thickened oil to the flash point temperature at which the oil produces sufficient vapors to ignite. The rules of thumb for minimum ignition thickness are listed in Table 3-6.

**TABLE 3-6  
MINIMUM IGNITABLE OIL THICKNESS ON WATER  
(ADAPTED FROM BUIST ET AL., (2003))**

OIL TYPE	MINIMUM THICKNESS
Light Crude and Gasoline	1 mm* (0.04 inches)
Weathered Crude and Middle-Distillate Fuel Oils (Diesel and Kerosene)	2 to 3 mm (0.08 to 0.12 inches)
Residual Fuel Oils and Emulsified Crude Oils	10 mm (0.4 inches)

\*mm – millimeters

The oil removal rate for in situ oil fires is a function of fire size (or diameter), slick thickness, oil type, and ambient environmental conditions. For most large (greater than 3 meter diameter) fires of unemulsified crude oil on water, the “rule-of-thumb” is that the burning consumption rate is 3.5 millimeters per minute (mm/min). Lighter fuels burn faster while heavier oils and emulsions burn slower, as shown in Table 3-7.

**TABLE 3-7  
BURN REMOVAL RATES FOR LARGE FIRES ON WATER  
(ADAPTED FROM BUIST ET AL., (2003))**

OIL TYPE/CONDITION	BURN/REMOVAL RATE
Gasoline >10 mm (0.4 inches) thick	4.5 mm/min (0.18 in/min*)
Distillate Fuels (diesel and kerosene) >10 mm (0.4 inches) thick	4.0 mm/min (0.16 in/min)
Crude Oil >10 mm (0.4 inches) thick	3.5 mm/min (0.14 in/min)
Heavy Residual Fuels >10 mm (0.4 inches) thick	2.0 mm/min (0.08 in/min)
Slick 5 mm thick <sup>1</sup>	90 percent of rate stated above
Slick 2 mm thick <sup>1</sup>	50 percent of rate stated above
Emulsified oil (percent of water content) <sup>2</sup>	Slower than above rates by a factor equal to the water content percent
Estimates of burn/removal rate based on experimental burns and should be accurate to within ±20 percent.	

\* inches per minute

<sup>1</sup> Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

<sup>2</sup> If ignited, emulsions will burn at a slower rate almost proportional to their water content (a 25-percent water-in-crude-oil emulsion burns about 25 percent slower than the unemulsified crude).

Burn rate is also a function of the size of the fire. Crude oil burn rates increase from 1 millimeter per minute (mm/min) with 3-foot diameter fires to 3.5 mm/min for 15-foot fires and greater. In situ burns on meltwater pools typically consume oil at 1 mm/min. For very large fires, on the order of 50 feet in diameter and larger, burn rates may decrease slightly because there is insufficient air in the middle of the fire to support combustion at 3.5 mm/min. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

An in situ oil fire extinguishes naturally when the slick burns down to a thickness that allows enough heat to pass through the slick to the water to cool the surface of the oil, below the temperature required for sustained combustion. The thickness at which an oil fire on water extinguishes is related to the type of oil and initial slick thickness. The rules of thumb are presented in Table 3-8. Other, secondary factors include

environmental effects such as wind (winds greater than 20 knots preclude in situ burning in most cases) current herding of slicks against barriers, and oil weathering.

**TABLE 3-8  
FIRE EXTINGUISHING SLICK THICKNESS  
{(ADAPTED FROM BUIST ET AL., (2003))}**

OIL TYPE/INITIAL SLICK THICKNESS	EXTINGUISHING THICKNESS
Crude Oil up to 20 mm (0.8 inches) thick	1 mm (0.04 inches)
Crude Oil 50 mm (2 inches) thick	2 to 3 mm (0.08 to 0.12 inches)
Distillate Fuels any thickness	1 mm (0.04 inches)

With an estimate of the initial thickness of a fully contained slick, or a measure of the burn time, it is relatively easy to estimate oil removal efficiency by burning. If not all of the slick area is on fire; the calculations need to account for this.

Oil-removal efficiency by in situ burning may be summarized as a function of the following key factors:

- Initial thickness of the slick,
- Thickness of the residue remaining, and
- Amount of the slick's surface that was on fire.

The water current maintains the oil thickness in the apex of a fire-resistant boom under tow, or against an ice edge in wind. When burning in a current, the fire slowly decreases in area until it reaches a size that can no longer support combustion. This herding effect can increase overall burn efficiencies, but it extends the time required to complete each burn.

The residue from a typical, efficient (greater than 85 percent removal) in situ burn of crude oil 10 to 20 mm thick is a semi-solid, tar-like layer that has an appearance similar to the skin on an old can of latex paint that has gelled. For thicker slicks, typical of what might be expected in a towed fire boom (about 150 to 300 mm), the residue can be a solid. Burn residue is usually denser than the original pre-burn oil, and usually does not spread due to its increased viscosity or solid nature.

Most unburned oil or burn residue following combustion would be transported from the vicinity of the blowout by wind or currents. Should any residue remain on the surface in the immediate area, it could be recovered by various means, including the use of booms in open-water conditions downstream of the burn area, or by response personnel using nets, poles, or other simple equipment over the side of small work-boats, subject to safe working conditions, weather, and available time. Disposal of any recovered residue would be in accordance with Appendix D.

Tests indicate that the burn residues from efficient burns of heavier crude oils (less than <32 degrees API gravity API) may sink once the residue cools, but their acute aquatic toxicity is very low or nonexistent. The "In Situ Burning Guidelines for Alaska" (ADEC, U.S. Environmental Protection Agency (EPA), and U.S. Coast Guard (USCG), March 2001) state, "The environmental advantages of in situ burning outweigh the potential environmental drawbacks of burn residue, including the possible environmental harm if the burn residue sinks. Therefore, the on-scene coordinators do not consider the potential impacts of burn residue when deciding whether to authorize an in situ burn." As required under 18 AAC 75.445-(h) and 18 AAC 75.425(e)(3)(G), Shell will also submit an "RRT-Regional Response Team In Situ Burn Application Form" to the Unified Command (See Section 1.7), which will include its plans for residue collection and disposal.

Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 percent to 80 percent range with some up to 90 percent. The oil in the emulsion cannot reach a temperature higher than 100 degrees Celsius (°C) until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used first, mostly to boil the water rather than heat the oil.

The following points summarize the effect of water content on the removal efficiency of weathered crude emulsions:

- Little effect on oil removal efficiency (i.e., residue thickness) for water contents up to about 12.5 percent by volume;
- A noticeable decrease in burn efficiency with water contents above 12.5 percent, the decrease being more pronounced with weathered oils;
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more; and
- Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents; Paraffinic crudes appear to fall into this category.

Fortunately, emulsion formation is slowed dramatically by high ice concentrations and may not be a significant operational factor in planning in situ burns on solid ice or naturally contained in higher concentrations of broken ice.

SL Ross et al. (2003) provides guidelines for burning thin slicks in broken ice with brash and slush, particularly relevant during the break-up and freeze-up shoulder seasons. General rules for minimum ignitable thickness and oil removal rates for burning thin slicks of crude oils on brash and/or slush with broken ice are as follows:

- The minimum ignitable thickness for fresh crude on frazil ice or small brash ice pieces is up to double that on open water, or about 1 to 2 mm,
- The minimum ignitable thickness for evaporated crude oil on frazil ice or small brash ice pieces can be higher than on open water, but is still within the range quoted for weathered crude on water, about 3 mm with gelled gasoline igniters.
- For a given spill diameter, the burn rate in calm conditions is about halved on relatively smooth frazil/slush ice and halved again on rougher, brash ice. Wave action slightly reduces the burn rate on open water, but the halving rule seems to also apply in waves.
- The residue remaining on broken ice in calm conditions is about 50 percent greater than that on open water, or 1.5 mm. The residue remaining on brash or frazil ice in waves is slightly greater than in calm conditions, at about 2 mm.

In summary, in situ burning of oil is efficient and rapid in broken ice conditions under the following conditions:

- The spilled oil is thicker than the minimum required for ignition (a thickness of 2 to 3 millimeters mm results in 50 to 66 percent removal efficiency: ~~10-millimeter-mm~~ thickness, a typical thickness for wind-herded slicks on melt ponds on ice, gives 90 percent removal efficiency);
- Larger areas can be ignited — (a 100-square foot slick on a meltwater pool will burn at 3.5 barrels of oil per hour (boph); a 50-foot diameter, 10-mm thick slick will burn at 300 boph; and a 100-foot diameter slick will burn at 1,200 boph);
- The oil is not more than 25 percent emulsified; and

- Herding in a current and enlarging fire diameters can increase burning rates.

The potential for efficient oil spill response (with or without burning) is strongly tied to the nature and amount of ice present. The following section addresses the seasonal ice conditions in Shell's area of interest in the Beaufort Sea during the proposed drilling season.

### Seasonal Ice Conditions

The following general description of the ice environment applies to the nearshore and offshore marine environments in the Alaskan Beaufort Sea, from shore out to the approximate 100-foot isobath representative of Shell's drilling locations. Descriptions cover typical conditions ~~as well as~~ and the variability in ice coverage and timing of the seasonal ice cycles. The focus is on a chronology most applicable to Shell's exploration program, starting with the first evidence of ice melt and clearing along the coast, and ending with the establishment of a stable fast ice cover nearshore and very close pack (9/10 or more) offshore in the November/December period. A brief description of the overall morphology and dynamics of winter ice conditions offshore is provided for completeness. See Dickins and Oasis (2006), Vaudrey (2000), and Atwater (1991) for further details.

#### May

The major river systems (Colville, Kuparuk, Sagavanirktok, and Colville) overflow the nearshore sea ice between mid-May and early June (average last week in May), based on 16 years of analysis presented in Atwater (1991). In any given year, the different rivers tend to flood within three to four days of each other. The maximum seaward extent of the floodwater reaches the 20-foot isobath between Stump Island and Northstar and the 10-foot isobath off Endicott and Niakuk.

The ice overflow along the coast triggers a rapid progression of local ice decay and break-up, fanning out in shallow water east and west from the major river ~~Δ~~deltas and eventually leading to an almost continuous open corridor from Harrison Bay to Camden Bay (see June below).

Ice concentrations in the offshore area (outside of the fast ice zone) in May are classified as very close pack ice of 9 to 9.5/10 (90 to 95 percent ice coverage). Recent analysis for the period 1996-2004 by Eicken et al. (2006) shows water depths at the fast ice edge in May off Flaxman Island ranging from 56 ~~feet~~ to more than 150 feet (averaging 98 feet). At this time, a broad open flaw lead often separates the fast ice inshore from the mobile pack ice offshore. This lead is highly variable in width and ~~E~~east/west extent and tends to become much less prevalent towards the end of May, and into June and July.

#### June

June 1 to July 15: Within the overflow zones, previously bottom-fast (grounded) ice in shallow water (less than 6-foot depth) lifts off the seabed and rapidly melts in place. The sea ice overflow often peaks at this time curtailing routine ice road operations. The influx of relatively warm water discharge into the inshore lagoons leads to early opening along shore in June, several weeks ahead of break-up offshore. First open water appears offshore of the Sagavanirktok and Kuparuk ~~R~~rivers in the period June 6 to June 13 and expands to include the lagoon side of West Dock (PM1) by June 17 on average. Fast ice beyond the overflow zones and outside the Barrier Islands is still intact at this time and often more than 5 feet thick in the first half of the month. Melt ponds usually cover less than 10 percent of the floating fast ice.

June 15 to July 25: Nearshore lagoon areas between Oliktok and West Dock, and in shallow waters off the Sagavanirktok delta, are mostly free of ice, and ice is starting to fracture and open south of the Endicott causeway. Further to the east, the initial clearing associated with flooding from the Staines and

West Canning Rivers expands around Brownlow Point to become contiguous with the much larger clearing off the Canning Delta. This connection generally occurs by late June.

The fast ice, still intact outside of the Barrier Islands gradually melts but is typically still 4 to 5 feet thick in many areas. The soft ice surface at this time is often 25 percent covered by melt-water pools that are rapidly deepening and expanding, with visible cracks and fractures. Ice deterioration is accelerated in areas where the surface is contaminated with dirt either left from drainage of overflow waters, or windblown off the nearby land (Vaudrey 2000).

Air temperatures at this time of year average 35 degrees-°F and range from 20 to 40 degrees-°F. The wind is variable, but blows 60 percent of the time from the E-east and NE-northeast, averaging 10 knots.

The fast ice can still support heavy equipment and low ground-pressure response vehicles up to the third week of June. The ability to achieve continued mobility on deteriorating sea ice with specific equipment is illustrated in ACS *Technical Manual*, Tactic L-7, based on field trials by Coastal Frontiers (2001).

The offshore area (100-foot water depth and beyond) still experiences 9/10<sup>th</sup> or greater ice concentration until the last week of June in most years.

## July

July 1: By the beginning of July, the open-water areas, which that originated from the Colville and the Kuparuk Rivers typically join to form a continuous band of open water stretching from the south shore of Atigaru Point in Harrison Bay to West Dock (Dickins and Oasis, 2006). By this time, the open water areas, which initially formed off the Shaviovik, Kadleroshik, and Sagavanirktok Rivers further west, have also joined to become a continuous coastal pathway of open water. The last nearshore area to clear (one to two weeks later) tends to be the coastal section between Point Thomson and Bullen Point (a coastal area not directly impacted by river overflow). The fast ice at this time is broken and mobile with drifting thick floes of variable concentration out to approximately 5 miles from shore.

In deeper water (Northstar vicinity or 30-foot water depths and beyond), the fast ice is still intact but badly deteriorated and vulnerable to break-up and fracturing by wind action. The ice at this time can still be 3 to 4 feet thick with many visible cracks and approximately 40 to 50 percent of the surface covered by meltwater pools and holes.

July 1 to July 7 (Typical): Break-up begins with fracturing and movement in the remaining floating landfast ice outside the Barrier Islands. The onset of break-up with fast ice in a severely weakened state is usually triggered by a wind event acting on parts of the sheet separated by natural lines of weakness indicated by a series of deep melt ponds or old thermal or stress cracks (Vaudrey in Dickins et al. 2000).

Pack ice concentrations in deeper water offshore (100 feet and vicinity) are typically in the range of 7-8/10<sup>th</sup>, a 20-percent reduction from the full winter concentration.

July 8 to July 12: Remaining fast ice remnants outside the Barrier Islands, off the Sagavanirktok River Delta and in Prudhoe Bay, survive as drifting floes in less than 7/10<sup>th</sup> concentration. As the winds shift direction, the broken ice floes and pans move back and forth in belts and patches of varying concentrations, all the while melting with a reduction in average floe size. First-year ice continues to deteriorate and break into smaller floes, creating large, highly variable openings in the remaining ice cover (Dickins et al. 2000).

July 15 to July 30: Ice-free water exists from shore out to Northstar and sites in equivalent water depths off the Endicott causeway and further east into Mikkelsen Bay. Ice invasions in the nearshore areas after this date are possible, but unlikely (Vaudrey, 2000). Ice concentrations in deeper water steadily diminish

through melting and wave and floe interactions over a period of two to three weeks. Remaining broken ice at this time moves back and forth in response to wind shifts, in belts and patches of varying concentrations. By the end of July or the first week of August, the study area typically becomes open water (defined as less than 1/10th ice concentration) out to water depths in the 40- to 65-foot range. Nearshore ice floe diameters rapidly shrink as the remaining fast ice decays and clears, starting out at 500 to 1,000 feet in the early stages and becoming ice cakes 30 to 40 feet in diameter by the third week in July.

Conditions in deeper water sites in the last half of July are highly variable, ranging from open water in unusually mild years (2 two years in ten) to a more typical condition of 7 to 8/10<sup>th</sup> thick first-year ice with floe sizes in the medium to big category (300 to 1,500 feet to and 1500 to 6500 feet). Periods of intermediate concentrations (4 to 6/10<sup>th</sup>) can occur in mid- to late July, but these conditions tend to be short lived.

#### August to September

Offshore, the first half of August typically encompasses the last stages of break-up, with open drift ice concentrations ranging from 2 to 6/10<sup>th</sup>. Extreme years can see variable patches of close pack ice in high concentrations during this period. Floe sizes range from small to medium for the predominantly first-year ice (60 to 300 feet to and 300 to 1,500 feet). Multi-year ice is often present in trace amounts (a few percent in coverage or much less than 1/10th) and rarely occurs in significant concentrations in the vicinity of Shell's drilling locations at this time of year (maximum reported 4/10th in two of the last ten years). (Source: Canadian Ice Service charts). Summer multi-year floe sizes tend to be larger than the surviving first-year pack (up to thousands of feet in diameter).

The nearshore area previously covered in stable ice, the winter fast ice zone, is completely open by the beginning of August in most years. Once established, open-water conditions in the coastal nearshore lagoon areas and adjacent to the Barrier Islands (typically in less than 10-foot water depths) generally prevail until freeze-up (see below). For example, there are no reported instances of drift ice entering the lagoon areas between Brownlow Point and Bullen Points during the summer months of August or September. The median duration of open water in the lagoon areas is 12 weeks, with a variability of up to two weeks representing summers better or worse than average in terms of break-up and freeze-up (Dickins, 1984). Immediately outside of the Barrier Islands (out to approximately the 50-foot-ft water depth), the duration of open water drops by about two weeks, and in some summers can be further reduced by several weeks through temporary pack ice invasions.

In the vicinity of the Shell's drilling locations, the average duration of open water (defined as 1/10th or less pack ice) is 7.5 weeks, with the most consistent period of continuous open water beginning mid-August and ending with first complete coverage of new ice in deep water in mid- to late October (based on a review of historical ice charts from 1997 to 2006).

Air temperatures average 40 degrees-°F in July and August, dropping to 30 degrees-°F in September. Wind blows from the E-east and NE-northeast 50 percent of the time, and W-west and southwest/SW 20 percent of the time, averaging 13 knots.

#### October

Freeze-up begins along shore in shallow water on October 4, ±8 days (Vaudrey, 2000). Ice becomes fast for the season within one week following freeze-up in the nearshore lagoons and at coastal locations such as Point McIntyre 2 and Niakuk. In deeper water north of the Barrier Islands (10 to 50 feet), the first continuous sheet forms on average by October 15 (Dickins and Oasis, 2006). By late October, ice movements inshore of the 30-foot water depth are infrequent, and the sheet is considered relatively

stable. Air temperatures at freeze-up range from 5°F to 15 degrees°F. Daylight in October is typically 9 to 10 hours per day (longer if twilight is included).

Additional time is required for the young fast ice sheet to gain sufficient thickness and stability to be judged safe for over-ice operations. Depending on location, the total time from initial freeze-up to being able to commence on-ice operations with response equipment ranges on average from 40 to 43 days at coastal or nearshore locations such as Niakuk and Endicott, to 55 days at the Northstar Production Island (Vaudrey, 2000).

#### November to December

An expanding fast ice zone, increasing in stability as the ice grows, characterizes this period. The young floating fast ice sheet outside the Barrier Islands is still vulnerable to break-up by storm events and positive surges in water levels until December in extreme years. At the nilas stage (defined as new ice less than 10 centimeters ~~em~~-thick) a moderate storm with winds over 20 knots can quickly break up the entire ice sheet.

For grey and grey-white ice between 4 and 12 inches, there is potential for break-up and/or substantial deformation and movement in strong winds over 27 knots. Storms of this severity in October and November are uncommon, on the order of two events during a ten-year period (Vaudrey, 2000).

The risk of substantial ice movements decreases sharply once the ice is greater than 12 inches. Extreme cases have been documented where portions of the land-fast ice have experienced substantial movement in early winter, but these are considered rare events. Vaudrey (2000) recounts only one year in 12 when a 20-inch thick ice sheet (a condition reached by late November in most years) moved 100 to 200 feet in the vicinity of Northstar. Movements of this magnitude would not result in visible open water, with the ice motion being absorbed by ridging and rubble formation.

During December when the floating fast ice reaches between 1.5 to 3 feet thick, ice motions are reduced to a range of 10 to 15 feet, based on measurements in 20 feet of water off the Barrier Islands to the west of Prudhoe Bay (Vaudrey, 1996).

The fast ice edge in early winter expands seaward from an average water depth of 15 feet in October and November, to 40 to 45 feet in December. (Eicken et al., 2006 based on data at 146 deg W Long.)

Beyond the fast ice edge and active shear zone, the pack ice can be divided into a highly active, often constantly deforming transition zone (seasonal pack) comprised of mostly first-year ice of highly variable age and thickness, and a more homogeneous polar pack with predominantly old (multi-year) ice. The polar pack edge (50 percent or greater coverage of multi-year ice) occurs in much deeper water well north of all of the proposed drilling locations.

In the early winter period (November to December) the transitional pack ice zone in the vicinity of the 100-foot water depth is comprised almost totally of first-year ice. No multi-year ice beyond trace amounts (much less than 10 percent coverage) was reported in the October to December time frame over the past ten years (1997-2006). The early winter pack ice consists of a mix of ice ages, from young ice less than 12 inches thick to thin first-year ice up to 27 inches. Once the ice begins to raft and rubble in November, level ice becomes the exception and much of the ice surface will represent some form of deformation process including the active formation of pressure ridges in December.

Pack ice moves in a meandering, net westerly drift in response to wind and currents. As the winter progresses and the pack becomes thicker and more consolidated, there are periods when little or no ice movement occurs in deep water. For example, a long-term ice drift record over ~~7~~-seven seasons shows that the monthly incidence of no ice motion typically increases from around 20 percent in November to

between 30 and 40 percent in December (Melling and Reidel, 2004). During these periods of static offshore ice, the boundary between the fast ice and pack ice zones can become blurred and indistinct. In these situations, mapping the boundary becomes a matter of interpreting the significance of a particular lead or crack.

When the pack ice is in its more typical dynamic drift mode, the fast ice boundary is clearly defined by a zone of massive shear and compression ridges stretching for hundreds of miles off the Alaskan North Coast. Many of these ridges can be grounded in water depths out to 80 feet with dramatic surface elevations up to 50 feet in some cases. The most active shear zone of severe ice deformation tends to be fairly narrow and concentrated between about 50 and 70 feet of water with no distinct east/west trends in severity (in some years it can extend into greater depths). In some areas a string of known shoals (e.g. Stamukhi off Oliktok) act to nucleate islands of grounded ice with dramatic fields of severe ridges and rubble (Kovacs, 1976; Reimnitz, 1984).

#### January to April

During the winter period of active ice growth, the fast ice continues to expand seaward reaching beyond 70 feet of water by February. The maximum fast ice extent occurs during the months of March to May when the water depths at the average edge position (off Flaxman Island) reach 100 feet, much deeper than the 60 feet boundary often discussed in earlier references (Eicken et al., 2006).

During the winter, east/west oriented leads (shore following) are common within the seasonal pack ice zone in water depths from 100 to 150 feet. Many of these leads will have widths ranging from hundreds of meters to miles and continue without blockage for long distances. In one study (Dickins, 1979), over half of all satellite images collected in the March to May time period showed distinct leads in this zone, becoming more frequent from west to east. Eicken et al. (2006) provides an extensive analysis of lead distributions, orientations, and dimensions within the pack ice zone.

The net mid-winter pack ice drift off the North Slope is to the west. On an hourly basis, pack ice motion tends to be episodic and meandering. In general, ice speeds are at a maximum (5 to 7 nm per day) with large expanses of young ice offshore in November and December, and decrease as the ice pack thickens and becomes more consolidated through January and February. Average pack ice drift speeds reach their minimum in March and April with typical values of 1.5 to 2.7 nm per day (Melling and Riedel, 2004). Four buoys were deployed by the USCG in the Beaufort nearshore between 1980 and 1985 in the winter period with high ice concentrations. Most of the buoy drift tracks of interest fell between 142°W and 150°W longitude in water depths from 60 to 200 feet. Results are summarized in Dickins (1984). The general movement trend and net drift was predominantly to the northwest, but there were also substantial periods when the buoys moved in other directions. For 40 to 60 percent of the recorded periods, the ice appeared to move without a persistent sense of direction (wallowing, meandering, or static). Vaudrey (2000) summarized the available historical ice movement data from a range of sources utilizing satellite drifter buoys from 1975 to 1996. Table 3-9 below shows daily averages for longer-term ice movements. Short-term ice drift speeds (over periods of 2 to 6 hours) can be significantly higher, in the range of 1 to 2 knots using 4 to 5 percent of the wind speed, as a rule of thumb.

**TABLE 3-9  
EXCEEDANCE PROBABILITY DISTRIBUTION OF ICE DRIFT SPEEDS**

SEASON	PERCENT > NET DAILY ICE MOVEMENT RATE (knots)							AVERAGE
	>0.2	>0.4	>0.6	>0.8	>1.0	>1.5	>2.0	SPEED (knots)
Freeze-Up	50.0	17.7	8.1	3.8	1.9	0.4	0.3	0.3
Break-Up	34.0	14.4	6.2	2.8	0.8	0	0	0.2

**Operational Preparedness**

Shell Oil and its contractor, ASRC Environmental Energy Services (AES), together with Alaska Clean Seas (ACS) maintain a comprehensive inventory of equipment to initiate and sustain in situ burning operations throughout the proposed drilling season. The Shell Beaufort and Chukchi Seas Regional Tactics Manual, AES' Response Tactics Manual and the ACS' Technical Manual contain specific tactical guidelines for the offshore operations with and without ice. Many of these tactics (e.g., Regional Tactics OR-1B, OR-2B, and OR-4B from AES and ACS Tactic R-20 from ACS) illustrate ways to intercept oil with an open-apex U-boom configuration so that thin or scattered oil slicks can be concentrated for recovery or captured downstream of the open-apex for burning within a fire boom.

Some of the tactics within each manual are specific with guidelines for implementing and sustaining burning on open water and in the presence of ice (e.g., AES' Regional Tactic OR-7 and ACS' Tactics B-3, B-4, B-5, B-6 and B-7). These tactics are incorporated in Shell's Beaufort Sea Regional Exploration Oil Discharge Prevention and Contingency Plan here by reference here, along with shoreline concepts for burning nearshore in Section 1.6.12, (Shoreline Cleanup) of the Shell C-plan.

ACS conducts in situ burn training seven to eight times a year at different North Slope locations. Typical courses involve at least an one hour of classroom instruction and an one hour of field exercises involving basic combustion theory, guidelines for safe operating procedures, and gelled fuel mixing and Heli-Torch deployment. Shell/AES personnel are also instructed on these same guidelines and procedures as they relate to the potential use of controlled burning offshore. ACS and AES maintain an inventory of specialized response equipment to support a large-scale burn operation as follows:

**TABLE 3-10  
INVENTORY OF IN SITU BURNING EQUIPMENT (ACS AND AES)**

EQUIPMENT	QUANTITY
<b>ACS</b>	
Fire Boom (20", 30" and 40" skirts)	19,000 feet
Heli-Torch (55 gal.)	6
Heli-Torch (300 gal.)	2
Heli-Torch SureFire gel	1,200 lb.
Air Deployable Igniters	>1,400
Heli-Torch Batch Mixers (gelled fuel)	2
<b>AES</b>	
HydroFire Boom (500' per system)	2
Cooling Water Pumps and Hoses	2

In addition, ACS and AES maintain all appropriate logistical support for controlled burning, including boom-tending vessels, helicopters, and vessels to transport and deploy equipment and ignition systems, and fire extinguishers.

Regulatory approval must first be obtained before using in situ burning, depending on whether the burning operations will be conducted in federal or state waters. The ACS *Technical Manual* (Tactics Description-B-1) contains steps that should be followed in reaching the decision to use in situ burning. As part of the approval process the "Alaska-Regional Response Team Application for In Situ Burning Application Form" will be submitted to the Unified Command according to the ARRT Unified Plan for Alaska, Appendix- 2, Annex F, *In Situ Burning Guidelines for Alaska*. An incident-specific burn plan is contained within the application.

Once relevant state and federal approval have been obtained, the following steps are normally taken to implement the response:

- Use towed open-apex boom configuration(s), as necessary, to concentrate and release oil directly into fire-resistant booms. Conventional boom may be used for this operation.
- Collect and contain the oil using fire-resistant booms. Re-locate the contained oil a safe distance from the open-apex configuration and other vessels.
- In light ice cover (with ice-deflection/management support), collect and contain oil using fire-resistant booms.
- In higher ice concentrations, locate naturally occurring pools of thick oil.
- As appropriate, use fire monitors and/or prop-wash to gently direct oil into heavier concentrations against ice floes or densely packed ice cakes. Wind may provide such desired herding of oil naturally.
- Ignite the oil using the Heli-Torch or hand-held igniters, following established safety procedures to avoid flashback or ignition of any ongoing spill source.
- Monitor the burn, maintaining constant watch on the fire and smoke plume. Maintain a careful assessment of fire boom condition (if used) and other safety hazards and issues as appropriate.
- Make every effort to recover and dispose of the burn residue.

Safety procedures and planning in accordance with established guidelines are emphasized throughout the training, preparation, and conduct of in situ burning operations.

In situ burns are monitored to ensure that fire does not spread to any uncontained oil nearby and that burns are conducted at safe operating distances from all vessels and personnel on location. Personnel and equipment used in conducting the operation are kept at safe distances from the spill source (ongoing natural gas normally already ignited). The safe working distances from an in situ fire on water depend on the size of the fire and the exposure time, and are summarized in Table 3-11.

**TABLE 3-11  
SAFE WORKING DISTANCES FROM THE FIRE**

PERSONNEL EXPOSURE TIME	PERSONNEL MINIMUM DISTANCE FROM FIRE (FIRE DIAMETERS)
Indefinite	4
30 minutes	3
5 minutes	2

Aerial ignition with gelled fuel from a Heli-Torch, or with other ignition devices, is coordinated, taking into account prevailing weather conditions, oil pool size and distribution, and the need for strict adherence to established safety practices.

ACS and AES personnel practice the techniques involved with controlled in situ burning at sea that could involve several vessels and aircraft working in close proximity.

### **Effectiveness of In Situ Burning in Open Water and in Ice**

The consensus of research on spill response with in situ burning of oil on open water and with ice is that burning is an effective technique with removal rates of 85 percent to 95 percent in most situations (Shell et al. 1983; SL Ross 1983; SL Ross and DF Dickins 1987; Allen 1990; Allen 1991; Allen and Ferek 1993; and Singaas et al. 1994). A considerable amount of research has demonstrated the success of in situ burning in broken ice. The research includes several smaller-scale field and tank tests (SL Ross et al. 2003; Shell et al. 1983; Brown and Goodman 1986; Buist and Dickins 1987; Smith and Diaz 1987; Bech et al. 1993; and Guénette and Wighus 1996) and one large field test (Singaas et al. 1994). Most of the tests involved large volumes of oil placed in a static test field of broken ice resulting in substantial slick thicknesses for ignition. Tests in unrestricted ice fields or in moving ice have indicated that the efficacy of in situ burning is sensitive to ice concentration and dynamics, and thus, the tendency for the ice floes to naturally contain the oil, the thickness (or coverage) of oil in leads between floes, and the presence or absence of brash or frazil ice which can absorb the oil.

The feasibility and efficiency of burning oil from a subsea blowout in the Beaufort Sea will depend in large part upon the nature of the oil as it surfaces and upon the nature and amount of ice present (if any). Studies within Shell have revealed that oil and gas from a subsea blowout (best represented by gas and oil flow rate characteristics from nearby reservoirs) could result in the atomization of oil due to turbulence from the gas plume. With this type of release, small droplets of oil would rise, along with the expanding gas, toward the surface where induced currents would then carry the oil droplets out radially from the source. Little, if any, emulsification is expected during the transport of oil toward the surface; however, within hours (depending upon the actual oil, wind/sea conditions) emulsification could reach levels that would make ignition difficult to impossible. The potential emulsification of the oil, together with the initial distribution of the oil droplets are factors that must be considered as one considers the potential use of in situ burning for the elimination of oil at or immediately downstream of the blowout.

The following information addresses the practicality of burning in open water and with varying concentrations of ice while recognizing the effects currents (primarily wind-driven) could have upon the distribution of oil and, therefore, the feasibility of collecting and igniting the oil.

### **Open Water with Current**

The initial distribution of the surfacing oil droplets in open water could involve a surface area with a diameter of several hundred meters. The outer reaches of this area would involve a relatively small percentage of the total blowout release as the largest droplets would surface more quickly near the center, and the smallest droplets would rise more slowly, riding with the induced currents to the outer regions of the slick. Depending on the current moving over the blowout, the oil droplets could surface into a clean (or relatively clear) water surface, where their initial spread would result in slicks that are too thin to support combustion (likely on the order of a tenth of a millimeter). Under these conditions (open water with current), combustion could effectively consume the free gas surfacing at the blowout; however, the relatively thin slicks would not support sustained combustion of the oil (typically requiring a 2 to 3 mm layer thickness). Authorization for ignition of the gas cloud directly over the blowout would normally be

requested as early as possible to avoid any risk of exposure to personnel on location and any accidental ignition that could expose personnel and equipment to fire.

Burning of the oil in this situation would require containment or deflection with boom to concentrate and thicken the oil while it is relatively fresh and unemulsified. Towed open-apex boom configurations could be used downstream of the blowout to thicken and release concentrated bands of oil into fire boom being towed in a U-configuration. Once such fire booms reach their holding capacity, they could be moved a safe distance from the open-apex, where ignition and sustained combustion could be quite successful. While burning the contained oil, a second fire boom could be positioned downstream of the open-apex to collect oil for a second burn. The elimination of oil at the first boom could easily be completed in time to relieve the second collection effort before the fire boom reaches its holding capacity.

### **Open Water with Little or No Current**

Should oil and gas be released from the seabed with little or no current, it is likely that authorization would have been secured (as in the previous scenario) to ignite the free gas directly over the blowout to avoid harmful exposures to personnel and any accidental ignition of the gas plume. Without current to sweep surfaced oil away from the blowout, there would be an accumulation of oil droplets at the surface allowing for the build up and re-coalescence of those droplets into a layer that could support combustion. In this case, it is likely that the heat generated by the burning of free gas would be sufficient to ignite vapors from the surfacing oil, thereby enlarging the burn area and removing a substantial portion of the blowout.

In this situation, it would not be necessary to use fire boom or to position personnel and equipment anywhere near the surfacing oil. The efficiency of removal by burning, however, could be improved if it was safe to deploy fire boom in a U-configuration at and immediately downstream of the surfacing oil and gas. The positioning of fire boom in this mode could be carried out safely if there was at least a light wind and/or a slight current that could carry the burning oil back into the apex of the U-configuration. Two boom-towing boats could be positioned well upstream of the surfacing oil and gas (using longer than normal tow lines) at a distance that would preclude any unsafe exposure to heat and smoke from the fire. Effective burning could be carried out without personnel, boats, and boom when the surfacing oil is held naturally at and near the spill source. In fact, the heated air rising above the blowout would produce a thermally-induced wind along the surface working radially in toward the fire. Even a very light breeze of this kind could help reduce spreading of the oil and maintain oil thickness for improved combustion. If currents less than 1 knot and/or light winds were available to move the burning oil away from the source, boom-tending boats could work at a safe distance from the burning source, and substantially improve the efficiency of burn.

### **Low-to-Moderate Ice Concentrations (with and without current)**

Even at ice concentrations of a couple of tenths, there could be sufficient ice (depending upon the size and distribution of the ice pieces) to reduce the effectiveness of conventional fire booms for the collection of oil. If the distribution of ice is such that ice could not be avoided or deflected away from the opening of a boom configuration, and ice could therefore accumulate to high concentrations within the boom, then boom could not be used effectively. Often, however, low ice concentrations are present as discontinuous wind-consolidated strips separated by broad open-water areas that may allow for the limited use of boom to capture oil. In more scattered ice concentrations, responders could access oil at low speeds and encounter rates between ice floes. At such low ice concentrations, there are times when burning could be conducted with fire boom.

Should broken ice (from as little as 2 to 3/10<sup>th</sup>s to as high as 7 to 8/10<sup>th</sup>s concentration) move into and over the blowout, the ice could actually help in a number of ways. The ice would tend to dampen waves,

reduce surface spreading radially over the blowout, and promote re-coalescence of the surfacing oil droplets in the reduced water surface between ice cakes or floes. Under these conditions, there would be an increased potential for the accumulation of oil on water at thicknesses that could support sustained combustion.

As long as the ice concentrations do not become excessive (>greater than 8 to 9/10<sup>ths</sup>) and/or the ice ~~is seen~~ under pressure, there should remain sufficient oil-on-water area to support combustion. ~~And~~ Also, as in the previous open-water scenarios, if water movement over the blowout drops to little or no current, the increased accumulation of oil between oil floes would only enhance the overall efficiency of burn. Induced radial currents over and adjacent to the blowout may prevent much of the oil from sticking to the underside of ice cakes and small floes. Most oil would therefore be exposed for combustion while it is fresh and relatively unemulsified. Should the natural floes be large enough to entrap some of the oil beneath them and keep the oil from surfacing, efforts could be initiated with icebreakers well upstream of the blowout to break such ice into smaller pieces or deflect large floes away from the blowout. Ice management is a proven technique that can completely modify the composition of the ice moving over a drilling location. For example, the successful 2004 coring program at 88°N saw two icebreakers work to maintain the drill ~~shiping~~ vessel on location in high concentrations of 7- to 9-foot ice. Floes drifting towards the drill site were over 3,000 feet in diameter. By the time they arrived, the icebreakers had reduced the average ice piece size to between 35 and 43 feet (Keinonen et al., 2006). In addition to managing the floe sizes, oil could be dislodged from the underside of ice (before it becomes encapsulated within the ice) using prop-wash from vessels on location.

Another approach that could enhance combustion with moving ice concentrations involves the use of large ice deflection barriers such as a barge with tug assist or a vessel with dynamic positioning. Shell has conducted extensive mathematical and ice-tank modeling efforts to show that such large-scale deflection of ice appears safe and feasible for the creation of a relatively ice-free surface downstream of the deflection operation. Pending the results of full-scale trials with ice, it is likely that moving broken ice and early freeze-up ice (new ice, nilas) could be deflected with a barge or vessel positioned side-ways to the current/ice flow. Temporary paths of relatively open water several hundred feet wide could be created downstream of the deflection system to facilitate the use of conventional containment and recovery tactics and/or the use of fire boom in a conventional burn mode.

#### **High Ice Concentrations and Continuous Layers of New Ice in Early Winter**

The movement of a continuous layer of new ice or very high ice concentrations of ice over a subsea blowout could reduce the effective use of in situ burning. There could be a reduction in the air/water surface area to accumulate oil and allow for efficient sustained combustion. This could be remedied in two ways: one involving the natural processes, and the other involving ice management. Experience has shown that large gas accumulations beneath ice will accumulate and rupture continuous ice layers (Dickins and Buist, 1981) during early freeze-up. The ice would likely break up, and move out and away from the blowout, rafting and accumulating to create a natural barrier within which burning of the oil and free gas could take place. The other remedy involves the use of large ice deflection systems upstream of the blowout as described above. Such deflection would provide an opening for burning on ice until prevented by excessive ice thickness. If the ice was continuous (even at relatively thin layers of say 3" to 6" inches) tank test results suggest that it would be necessary to use ice-breakers forward of the deflection system. As long as the ice could be broken, and it is not too thick or pressured, it is possible that a relatively ice-free path could be opened just forward (or upstream) of the blowout. Oil (even widely scattered particles) surfacing within the cleared path downstream of the deflection system would soon be trapped within the downstream opening bounded on each side by ice. Even if bounded by broken ice and



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
WASHINGTON D.C. 20460

OFFICE OF THE ADMINISTRATOR  
SCIENCE ADVISORY BOARD

September 29, 2006

EPA-CASAC-LTR-06-003

Honorable Stephen L. Johnson  
Administrator  
U.S. Environmental Protection Agency  
1200 Pennsylvania Avenue, NW  
Washington, DC 20460

Subject: Clean Air Scientific Advisory Committee Recommendations Concerning the  
Final National Ambient Air Quality Standards for Particulate Matter

Dear Administrator Johnson:

We, the seven members of the Clean Air Scientific Advisory Committee (CASAC or Committee), are writing to express our serious scientific concerns regarding the public health and welfare implications of EPA's final primary (health effects) and secondary (welfare effects) National Ambient Air Quality Standards (NAAQS) for airborne particulate matter (PM). As you know, the CASAC is mandated by the Clean Air Act to provide scientific advice on the setting of these standards that are intended to protect both public health and public welfare, and in the case of the protection of public health, to do so with "an adequate margin of safety." The Committee has conscientiously fulfilled its duty in providing our best scientific advice and recommendations to the Agency. Regrettably, however, EPA's final rule on the NAAQS for PM does not reflect several important aspects of the CASAC's advice.

In its letter dated June 6, 2005, the CASAC recommended that the 24-hour standard for  $PM_{2.5}$  be decreased from 65 micrograms per cubic meter ( $\mu\text{g}/\text{m}^3$ ) to 30–35  $\mu\text{g}/\text{m}^3$ . We are pleased with the Agency's decision in the final PM NAAQS rule to decrease the daily primary  $PM_{2.5}$  standard to a level consistent with the CASAC's recommendation (35  $\mu\text{g}/\text{m}^3$ ), as this decrease will provide additional health protection in some cities. In addition, we recommended a decrease in the annual primary  $PM_{2.5}$  standard from 15  $\mu\text{g}/\text{m}^3$  to 13–14  $\mu\text{g}/\text{m}^3$ . However, the CASAC is concerned that EPA did not accept our finding that the annual  $PM_{2.5}$  standard was not protective of human health and did not follow our recommendation for a change in that standard.

The CASAC recommended changes in the annual fine-particle standard because *there is clear and convincing scientific evidence that significant adverse human-health effects occur in response to short-term and chronic particulate matter exposures at and below 15  $\mu\text{g}/\text{m}^3$ , the level of the current annual  $PM_{2.5}$  standard.* The CASAC affirmed this recommended reduction in the annual fine-particle standard in our letter dated March 21, 2006 concerning the proposed rule for the PM NAAQS, in which 20 of the 22 members of the CASAC's Particulate Matter

Review Panel — including all seven members of the chartered (statutory) Committee — were in complete agreement. While there is uncertainty associated with the risk assessment for the PM<sub>2.5</sub> standard, this very uncertainty suggests a need for a prudent approach to providing an adequate margin of safety. *It is the CASAC's consensus scientific opinion that the decision to retain without change the annual PM<sub>2.5</sub> standard does not provide an "adequate margin of safety ... requisite to protect the public health" (as required by the Clean Air Act), leaving parts of the population of this country at significant risk of adverse health effects from exposure to fine PM.*

*Significantly, we wish to point out that the CASAC's recommendations were consistent with the mainstream scientific advice that EPA received from virtually every major medical association and public health organization that provided their input to the Agency, including the American Medical Association, the American Thoracic Society, the American Lung Association, the American Academy of Pediatrics, the American College of Cardiology, the American Heart Association, the American Cancer Society, the American Public Health Association, and the National Association of Local Boards of Health. Indeed, to our knowledge there is no science, medical or public health group that disagrees with this very important aspect of the CASAC's recommendations.* EPA's recent "expert elicitation" study (*Expanded Expert Judgment Assessment of the Concentration-Response Relationship Between PM<sub>2.5</sub> Exposure and Mortality*, September 21, 2006) only lends additional support to our conclusions concerning the adverse human health effects of PM<sub>2.5</sub>.

Furthermore, the CASAC was completely surprised at the decision in the final PM NAAQS to revert to the use of PM<sub>10</sub> as the indicator for coarse particles. In our September 15, 2005 letter, the CASAC recommended a new indicator of PM<sub>10-2.5</sub>, which EPA put forward in its proposed rule for the PM NAAQS. The option of retaining the existing daily PM<sub>10</sub> standard of 150 µg/m<sup>3</sup> was not discussed during the advisory process, and in fact the CASAC views this as highly-problematic since PM<sub>10</sub> includes both fine and coarse particulate matter. The Committee acknowledges the need for the Agency to increase its understanding of the health risks of coarse particles and is concerned that ongoing dependence on PM<sub>10</sub> sampling as an imprecise measure of coarse particulate matter will provide inadequate information on coarse PM concentrations, compositions and exposures in both urban and rural areas. However, the CASAC agrees that having a standard for PM<sub>10</sub> is better than no standard at all for coarse particles, and was pleased with the Agency's decision against offering exemptions to specific industries (*i.e.*, agricultural, mining) in its regulation of coarse particles.

With respect to the secondary PM standard, the decision was made "to revise the current PM secondary standards by making them identical in all respects to the revised suite of primary PM standards." In our June 6, 2005 letter, the CASAC affirmed the recommendation of Agency staff regarding a separate secondary fine particle standard to protect visibility. This sub-daily secondary PM<sub>2.5</sub> standard is a better indicator of visibility impairment than the 24-hour primary standard. The CASAC wishes to emphasize that continuing to rely on primary standards to protect against all PM-related adverse environmental and welfare effects assures neglect, and will allow substantial continued degradation, of visual air quality over large areas of the country.

In summary, the Agency has rejected the CASAC's expert scientific advice with regard to lowering the level of the annual primary fine particle (PM<sub>2.5</sub>) standard and establishing a new

coarse particle (PM<sub>10-2.5</sub>) standard — both of which are consistent with the recommendations of the nationally-recognized science, medical and public health groups such as those cited above — and, in addition, EPA has not followed our advice in setting a separate secondary PM<sub>2.5</sub> standard. We note that, since the CASAC's inception in the late 1970s, the Agency has always accepted the Committee's scientific advice with regard to final NAAQS decisions. In view of this, we question whether you have appropriately given full consideration to CASAC's expert scientific advice — obtained through open, public processes — in your final decisions on the PM NAAQS.

The CASAC shares a common goal with EPA to protect the public health and welfare. We earnestly hope that the Agency's future consideration of the CASAC's scientific advice with respect to standard-setting for the criteria air pollutants will prove more fruitful in achieving that very important goal.

Sincerely,

*/Signed/*

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Scientist Emeritus  
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Frederick J. Miller, Ph.D.  
Cary, NC  
Consultant

Dec. 1, 2000

MEMORANDUM

SUBJECT: EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting

FROM: Gary S. Guzy //signed//  
General Counsel  
Office of General Counsel (2310A)

TO: Steven A. Herman  
Assistant Administrator  
Office of Enforcement and Compliance Assistance (2201A)

Robert Perciasepe  
Assistant Administrator  
Office of Air and Radiation (6101A)

Timothy Fields, Jr.  
Assistant Administrator  
Office of Solid Waste and Emergency Response (5101)

J. Charles Fox  
Assistant Administrator  
Office of Water (4101)

This memorandum analyzes a significant number of statutory and regulatory authorities under the Resource Conservation and Recovery Act, the Clean Water Act, the Safe Drinking Water Act, the Marine Protection, Research, and Sanctuaries Act, and the Clean Air Act that the Office of General Counsel believes are available to address environmental justice issues during permitting. The use of EPA's statutory authorities, as discussed herein, may in some cases involve new legal and policy interpretations that could require further Agency regulatory or interpretive action. Although the memorandum presents interpretations of EPA's statutory authority and regulations that we believe are legally permissible, it does not suggest that such actions would be uniformly practical or feasible given policy or resource considerations or that there are not important considerations of legal risk that would need to be evaluated. Nor do we assess the relative priority among these various avenues for addressing environmental justice concerns. We look forward to working with all your offices to explore these matters in greater detail.

The MPRSA, commonly known as the Ocean Dumping Act, 33 USC § 1401 ff., establishes a permitting program that covers the dumping of material into ocean waters. The ocean disposal of a variety of materials, including sewage sludge, industrial waste, chemical and biological warfare agents, and high level radioactive waste, is expressly prohibited.

EPA issues permits for the dumping of all material other than dredged material. 33 U.S.C. § 1412(a). The Army Corps of Engineers issues permits for the dumping of dredged material, subject to EPA review and concurrence. 33 U.S.C. § 1413(a). (As a practical matter, EPA issues very few ocean dumping permits because the vast majority of material disposed of at sea is dredged material.) EPA also is charged with designating sites at which permitted disposal may take place; these sites are to be located wherever feasible beyond the edge of the Continental Shelf. 33 U.S.C. § 1412(c)(1).

When issuing MPRSA permits and designating ocean dumping sites, EPA is to determine whether the proposed dumping will "unreasonably degrade or endanger human health, welfare, amenities, or the marine environment, ecological systems, or economic potentialities." 33 USC § 1412(a), (c)(1). EPA also is to take into account "the effect of... dumping on human health and welfare, including economic, esthetic, and recreational values." 33 U.S.C. § 1412(a)(B), (c)(1). Thus, in permitting and site designation, EPA has ample authority to consider such factors as impacts on minority or low-income communities and on subsistence consumers of sea food that would result from the proposed dumping. In addition, the MPRSA provides specifically that EPA is to consider land-based alternatives to ocean dumping and the probable impact of requiring use of these alternatives "upon considerations affecting the public interest." 33 U.S.C. § 1412(a)(G). This authorizes EPA to take impacts on minority populations or low-income populations into account in evaluating alternative locations and methods of disposal of the material that is proposed to be dumped at sea.

## **V. Clean Air Act (CAA)**

There are several CAA authorities under which EPA could address environmental justice issues in permitting:

### **A. New Source Review (NSR)**

NSR is a preconstruction permitting program. If new construction or making a major modification will increase emissions by an amount large enough to trigger NSR requirements, then the source must obtain a permit before it can begin construction. The NSR provisions are set forth in sections 110(a)(2)(C), 165(a) (PSD permits), 172(c)(5) and 173 (NSR permits) of the Clean Air Act.

Under the Clean Air Act, states have primary responsibility for issuing permits, and they can customize their NSR programs within the limits of EPA regulations. EPA's role is to

approve State programs, to review, comment on, and take any other necessary actions on draft permits, and to assure consistency with EPA's rules, the state's implementation plan, and the Clean Air Act. Citizens also play a role in the permitting decision, and must be afforded an opportunity to comment on each construction permit before it is issued.

The NSR permit program for major sources has two different components—one for areas where the air is dirty or unhealthy, and the other for areas where the air is cleaner. Under the Clean Air Act, geographic areas (e.g., counties or metropolitan statistical areas) are designated as “attainment” or “nonattainment” with the National Ambient Air Quality Standards (NAAQS)—the air quality standards which are set to protect human health and the environment. Permits for sources located in attainment (or unclassifiable) areas are called Prevention of Significant Deterioration (PSD) permits and those for sources located in nonattainment areas are called NSR permits.

A major difference in the two programs is that the control technology requirement is more stringent in nonattainment areas and is called the Lowest Achievable Emission Rate (LAER). On the other hand, in attainment or PSD areas, a source must apply Best Available Control Technology (BACT) and the statute allows the consideration of cost in weighing BACT options. Also, in keeping with the goal of progress toward attaining the national air quality standards, sources in nonattainment areas must always provide or purchase “offsets”—decreases in emissions which compensate for the increases from the new source or modification. In attainment areas, PSD sources typically do not need to obtain offsets. However, PSD does require an air quality modeling analysis of pollution that exceeds allowable levels; this impact must be mitigated. Sometimes, these mitigation measures can include offsets in PSD areas.

1. Under the Clean Air Act, section 173(a)(5) provides that a nonattainment NSR permit may be issued only if: "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification." For example, this provision authorizes consideration of siting issues. Section 165(a)(2) provides that a PSD permit may be issued only after an opportunity for a public hearing at which the public can appear and provide comment on the proposed source, including "alternatives thereto" and "other appropriate considerations." This authority could allow EPA to take action to address the proper role of environmental justice considerations in PSD/NSR permitting.
2. In addition to these statutory provisions, EPA directly issues PSD/NSR permits in certain situations (e.g., in Indian country and Outer Continental Shelf areas) and, through the EAB, adjudicates appeals of PSD permits issued by States and local districts with delegated federal programs. In such permit and appeal decisions, it is possible to consider environmental justice issues on a case-by-case basis, without waiting to issue a generally applicable rule or guidance document. EPA already considers environmental

justice issues on a case-by-case basis in issuing PSD permits consistent with its legal authority.

3. The EPA Environmental Appeals Board (EAB) has addressed environmental justice issues in connection with PSD permit appeals on several occasions. The EAB first addressed environmental justice issues under the CAA in the original decision in Genessee Power (September 8, 1993). In that decision the EAB stated that the CAA did not allow for consideration of environmental justice and siting issues in air permitting decisions. In response, the Office of General Counsel filed a motion for clarification on behalf of the Office of Air and Radiation (OAR) and Region V. OGC pointed out, among other things, that the CAA requirement to consider alternatives to the proposed source, and the broad statutory definition of “best available control technology” (BACT), provided ample opportunity for consideration of environmental justice in PSD permitting. In an amended opinion and order issued on October 22, 1993, the EAB deleted the controversial language but did not decide whether it is permissible to address environmental justice concerns under the PSD program. 4 E.A.D. 832, 1993 WL 484880, <<http://www.epa.gov/eab/disk4/genessee.pdf>>. However, in subsequent decisions, Ecoeléctrica, 7 E.A.D. 56, 1997 WL 160751 (1997) <<http://www.epa.gov/eab/disk11/ecoelect.pdf>>, and Puerto Rico Electric Power Authority, 6 E.A.D. 253, 1995 WL 794466 (1995) <<http://www.epa.gov/eab/disk9/prepa.pdf>>, the EAB stated that notwithstanding the lack of formal rules or guidance on environmental justice, EPA could address environmental justice issues. In 1999 in Knauf Fiber Glass, 8 E.A.D. PSD Appeal Nos. 98-3 through 98-20, 1999 WL 64235 (Feb. 4, 1999) <<http://www.epa.gov/eab/disk11/knauf.pdf>>, the EAB remanded a PSD permit to the delegated permitting authority (the Shasta County Air Quality Management District) for failure to provide an environmental justice analysis in the administrative record in response to comments raising the issue.
4. In the 1990 CAA Amendments, Congress provided that the PSD provisions of the Act do not apply to hazardous air pollutants (HAPs), see CAA section 112(b)(6), so the role of hazardous air pollutant impacts as environmental justice issues in PSD permitting is not straightforward. Thus, BACT limits are not required to be set for HAPs in PSD permits. However, the Administrator ruled prior to the 1990 Amendments that in establishing BACT for criteria pollutants, alternative technologies for criteria pollutants could be analyzed based on their relative ability to control emissions of pollutants not directly regulated under PSD. EPA believes that the 1990 Amendments did not change this limited authority, and EPA believes it could be a basis for addressing environmental justice concerns. In addition, EPA may have authority to take into account – and to require States to do so in their PSD permitting – effects of HAPs that are also criteria pollutants, such as VOCs.

**B. Title V**

Title V of the CAA requires operating permits for stationary sources of air pollutants and prescribes public participation procedures for the issuance, significant modification, and renewal of Title V operating permits. Unlike PSD/NSR permitting, Title V generally does not impose substantive emission control requirements, but rather requires all applicable requirements to be included in the Title V operating permit. Other permitting programs may co-exist under the authority of the CAA, such as those in State implementation plans (SIPs) approved by EPA.

1. Because Title V does not directly impose substantive emission control requirements, it is not clear whether or how EPA could take environmental justice issues into account in Title V permitting – other than to allow public participation to serve as a motivating factor for applying closer scrutiny to a Title V permit’s compliance with applicable CAA requirements. EPA believes, however, that in this indirect way, Title V can, by providing significant public participation opportunities, serve as a vehicle by which citizens can address environmental justice concerns that arise under other provisions of the CAA.
2. Under the 40 CFR Part 70/71 permitting process, EPA has exercised its CAA authority to require extensive opportunities for public participation in permitting actions. State permitting authorities also have the flexibility to provide additional public participation.
3. Other permitting processes under the CAA such as SIP permitting programs can include appropriate public participation measures, and these can be used to promote consideration of environmental justice issues. For example, EPA regulations require that “minor NSR programs” in SIPs provide an opportunity for public comment prior to issuance of a permit (40 CFR § 51.161(b)(2)). (Note, however, that many state programs do not at present meet this requirement.)

### **C. Solid Waste Incinerator Siting Requirements**

The CAA provides specific authority to EPA to establish siting requirements for solid waste incinerators that could include consideration of environmental justice issues. CAA section 129(a)(3) provides that standards for new solid waste incinerators include "siting requirements that minimize, on a site specific basis, to the maximum extent practicable, potential risks to public health or the environment." These would be applicable requirements for Title V purposes. The new source performance standards (NSPS) for large municipal waste combustors (40 CFR part 60, subpart Eb) and hospital/medical/infectious waste incinerators (40 CFR part 60, subpart Ec) both currently contain such requirements. In the large municipal waste combustor NSPS, the specific requirement in section 129(a)(3) was incorporated and requirements for public notice, a public meeting and consideration of and response to public comments were added. However, to reduce the burden on the much smaller entities which typically own and operate hospital/medical/infectious waste incinerators, that NSPS only incorporates the specific section 129(a)(3) requirement. EPA is subject to a court ordered deadline for

taking final action on NSPS for commercial/industrial waste incinerators, and has proposed to follow the approach to the siting analysis adopted in the hospital/medical/infectious waste NSPS in that rule.

**D. 40 CFR Part 71 Tribal Air Rule**

The Part 71 federal operating permit rule establishes EPA's Title V operating permits program in Indian country. Where sources are operating within Indian country, and Tribes do not seek authorization to implement Title V programs, the Part 71 rule clarifies that EPA will continue to implement federal operating permit programs. These Title V permit programs are limited to Title V and other applicable federal CAA requirements and are not comprehensive air pollution control programs. Thus, the opportunities for addressing environmental justice issues may be similar to those discussed in section B above.

cc: Michael McCabe  
Barry Hill  
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