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October 20, 2009

Via Electronic Mail

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Shell Chukchi OCS Air Permit
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Re: Shell Gulf of Mexico/Shell Offshore Inc.'s Application for a Chukchi Sea Clean Air Act Permit.

Dear Ms. Helm and Mr. Nair:

Thank you for the opportunity to comment on Shell's Clean Air Act (CAA) permit application materials, EPA's proposed permit and statement of basis for that permit. Because of our unified interest in minimizing the impacts of air pollution and global warming in our Arctic communities and surrounding environment these comments are signed and submitted jointly on behalf of the Alaska Eskimo Whaling Commission (AEWC), the Inupiat Community of the Arctic Slope (ICAS), and the North Slope Borough (NSB).

At the outset, we wish to express our sincere thanks to you and your fellow staff at EPA for visiting the North Slope and meeting with representatives from each of our organizations to discuss this proposed permit. Your efforts demonstrate a good faith effort to meaningfully consider our comments and concerns. We are encouraged by your efforts and submit these comments to assist you in your ongoing review of Shell's proposed action. We hope that you will permit the proposed emissions only when their impact to the health and welfare of our people is minimized to the greatest extent possible and we have provided these unified comments to assist you in doing so.

As you know, the AEWC is a non-profit organization representing Inupiat whaling captains in Northern Alaska. AEWC represents the eleven bowhead whale subsistence hunting villages of Barrow, Nuiqsut, Kaktovik, Pt. Hope, Kivalina, Wales, Savoonga, Gambell, Little Diomede,

Exhibit 3
AEWC & ICAS

Wainwright, and Pt. Lay. Our whaling captains and their communities rely upon the health of the Chukchi and other seas to provide for marine life, which in turn sustain our people and our culture. On behalf of our whaling captains, AEWC is responsible for protecting the bowhead whale and the subsistence way of life that the Arctic Ocean supports. The AEWC's Inupiat and Siberian Yupik whaling captains have thousands of years of traditional knowledge about the Arctic ecosystem, and AEWC is also well versed in the current science regarding the health and status of the natural resources of the Arctic.

ICAS is a regional tribal government for eight villages on the North Slope that depend upon the marine mammals that live and migrate through the Chukchi and Beaufort Seas. The Chukchi Sea is a unique place with great cultural significance for the Inupiat who hunt and fish in this area. We have previously experienced oil and gas activities in the Arctic that caused direct conflicts with subsistence activities and the resources that have sustained the Inupiat people since time immemorial. Thus, history has taught us that areas that are important to Inupiat subsistence activities and cultural preservation are put at risk by offshore oil and gas activities and require careful review.

The NSB has the largest territorial and coastal jurisdiction of any municipal government in the United States, an area larger than the State of Minnesota. The Borough has multiple interests at stake in Shell's proposed Chukchi Sea Exploration Plan underlying this CAA permit. First and foremost are the NSB's interests related to the health and welfare of our residents, who are rightfully concerned about potential health impacts associated with oil and gas development on the North Slope. These impacts may be direct, indirect or cumulative in nature and relate to the contamination and degradation of the natural environment upon which its residents rely.

Our communities include those that are onshore from Shell's proposed operations and those that rely upon the resources from the Chukchi Sea that will be impacted by Shell's proposal. The Chukchi Sea is a unique and diverse marine environment and Shell's proposed air emissions threaten this environment and the life it supports. Ocean-going vessels such as those Shell is proposing to use have been recognized as major contributors to global climate change as a result of their carbon dioxide (CO_2) emissions, and as significant emitters of pollutants harmful to human health, such as nitrogen oxides (NOx), sulfur oxides (SOx), and particulate matter (PM).[1] Indeed, EPA recognized that

> in 2001 marine diesel engines with per-cylinder displacement of 30 liters or more (a group roughly corresponding to the engines covered by the new IMO [International Maritime Organization] standards) contributed 6% of the NOx coming from all mobile sources in the U.S., as well as 10% of the PM, and 40% of the SOx. We further estimate that without new emission controls, these contributions would have increased by 2030 to 34% of the NOx coming from all mobile sources in the U.S., 45% of the PM, and 94% of the SOx.[2]

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[1] The International Council On Clean Transportation, Air Pollution and Greenhouse Gas Emissions from Ocean-going Ships: Impacts, Mitigation Options and Opportunities for Managing Growth (2007) (available at: http://www.theicct.org/documents/MarineES_ Final_Web.pdf).

[2] EPA, Program Announcement: International Maritime Organization Adopts Program to Control Air Emissions from Oceangoing Vessels (2008) (available at: http://www.epa.gov/ oms/regs/nonroad/marine/ci/420f08033.pdf).

We are rightfully concerned about the ramifications of these emissions and the purpose and need for the overall action as proposed, given the significance of its potential and disproportionate impacts on our people.

The people who will be affected by Shell's air emissions live in isolated areas, enjoy a lifestyle and diet that is radically different from other U.S. populations, have markedly higher rates of pulmonary disease than the general U.S. population (and therefore are substantially more vulnerable to morbidity and mortality from air pollution), and may have genetic predispositions to disease that differ from other U.S. populations. A human health impact assessment and more thorough ambient air modeling, and baseline emission assessments are needed to assure that human health is protected. Such analyses should acknowledge that abundant public health data demonstrate that vulnerable populations such as those along the North Slope experience disproportionately high mortality rates.

We commend EPA for improving its implementation of the OCS permitting process over the process that was followed in 2007 by requiring Best Available Control Technologies (BACT) on the Discoverer emission sources, establishing more rigorous monitoring, and implementing record keeping and reporting requirements. However, as demonstrated in the attached comments, considering the significant emissions posed by this action, we have identified a number of areas where additional revision is required in the proposed permit to conform to the CAA and its regulations. These areas include:

(1) the need for EPA to regulate the carbon dioxide (CO_2) emissions from Shell's proposed operations;

(2) the need to apply Best Available Control Technologies (BACT) to all the vessels and engines associated with Shell's proposed activities at the drill site;

(3) the need to more thoroughly apply BACT to those vessels and engines that are currently being regulated;

(4) the need to comply with several other environmental laws before a permit is issued to Shell; and

(5) the need for Shell to complete, and for EPA to review its permit application and rectify and reconcile the inconsistent statements made regarding its plans for the Chukchi Sea.

Until these areas of concern are resolved, we ask that a permit not be issued for the proposed offshore oil and gas exploration emissions. There are demonstrated and required means for the considerable reduction of air emissions associated with this action. These means should be implemented, to assure compliance with federal law, and most importantly, to avoid unnecessary impacts to the health and welfare of our people. Thank you again for the opportunity to comment. Please feel free to contact us if you have

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questions regarding any of our comments.

Sincerely,

Harry Brower
AEWC
Chairman

Doreen Lampe
ICAS
Chairwoman

Edward S. Itta
North Slope Borough
Mayor

CC'd By First Class or Electronic Mail:

Senator Lisa Murkowski
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Representative Don Young
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AEWC, ICAS, AND NORTH SLOPE BOROUGH COMMENTS REGARDING SHELL GULF OF MEXICO AND SHELL OFFSHORE INC.'S APPLICATION FOR AN OCS PSD PERMIT UNDER THE CLEAN AIR ACT FOR ITS CHUKCHI SEA OPERATIONS.

At the outset, Shell's application has been amended, corrected, and supplemented numerous times since it was originally submitted in December 2008, making the application very cumbersome for us to review. Our people have had to wade through thousands of pages of proposals, corrections and correspondence between Shell and EPA to determine how Shell's operations have been modified and to locate technical support data. While we disagree with the determination that Shell's permit application is complete (for the reasons discussed below), we also believe that Shell never submitted a final permit application that embodies all the revisions it agreed to make. A final complete application needs to be submitted for us to review and comment upon.[1]

Most recently, on September 18, 2009, over a month into the public comment period, Shell provided additional corrections and supplements to its already complicated application and proposed submitting data at a later, yet to be determined date.[2] As evidenced by Shell's latest revisions and as stated above Shell has thus not submitted a complete, final permit application ripe for public review and comment. We therefore request that Shell be required to correct and consolidate its permit application into one complete document that is made available to the public for review. In conjunction with such a submission we ask that EPA "[p]repare a new draft permit, appropriately modified, under § 124.6," "a revised statement of basis under sec. 124.7"[3] and provide 30 days for the public to comment on the amended draft permit and accompanying materials.[4]

[1] With respect to Shell's PSD permit for its Beaufort Sea proposed operations, EPA stated "[i]ncorporating by reference components of the Chukchi Sea permit application in the Beaufort Sea application will slow EPA's review of the application, complicate the public review process, and lead to possible errors" and asked Shell to "submit a revised application that includes the relevant portions of the information [Shell] submitted for the" Chukchi. Letter from Richard Albright, EPA to Susan Childs, Shell (Sept. 4, 2009). We request that EPA ask Shell to submit a revised application here as it did with Shell's Beaufort application.

[2] *See* Shell, Sept. 18, 2009 Submission (available at: http://yosemite.epa.gov/R10/airpage.nsf/Permits/chukchiap/$FILE/chukchi_shell_comments_091709.pdf).

[3] 40 C.F.R. § 124.15(b)(1)-(2)

[4] *See, e.g., In re: Indeck-Elwood L.L.C.*, PSD APPEAL 03-04, Slip Op. at 30, 13 E.A.D. --- (Sept. 27, 2006) (remanding permit where the issuing agency added a "permit condition after the close of the public comment period" that "changed the substance of the PSD permit" including by "potentially" allowing "different emission characteristics").

STATUTORY AND FACTUAL BACKGROUND.

Statutory Background.

The prevention of significant deterioration (PSD) program was added to the Clean Air Act (CAA) in 1977. The PSD program helps ensure that national ambient air quality standards (NAAQS) are attained. It requires new major stationary sources to obtain preconstruction permits in areas where the NAAQS have been attained (attainment areas).[5] In 1990, Congress decided to regulate air pollution in the Outer Continental Shelf (OCS) by amending the CAA to include the OCS program which regulates offshore entities by requiring them "to attain and maintain Federal and State ambient air quality standards and to comply with the" PSD program.[6] EPA has promulgated regulations to control air pollution on the outer continental shelf (OCS) for this purpose.[7]

Under the PSD program if an OCS source is located 25 miles beyond a state's seaward boundary that source is "subject to the New Source Performance Standards (NSPS), in 40 C.F.R Part 60."[8] If the OCS source qualifies as "a major stationary source," then the standards promulgated under "Section 112 of the CAA if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of Part C of Title I of the CAA" – i.e., the NESHAPs – apply to the source.[9] The potential for the OCS source to emit NSR pollutants[10] must be calculated and the OCS source must apply for a Title V operating permit.[11]

The "PSD program includes a requirement" that the permit applicant evaluate "the effect that the proposed emissions are expected to have on air quality related values such as visibility, soils, and vegetation."[12] Before issuing a Prevention of Significant Deterioration (PSD) permit to a major new stationary source (source), the EPA must conduct a Best Available Control Technology (BACT) analysis for each pollutant that the source has the potential to emit pollutants in significant quantities.[13]

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[5] 42 U.S.C. § 7475.
[6] 42 U.S.C. § 7627(a)(1).
[7] *See* 40 C.F.R. part 55.
[8] EPA, Region 10, Statement of Basis for Proposed Outer Continental Shelf Prevention of Deterioration Permit No. R10OCS/PSD-AK-09-01 Shell Gulf of Mexico Inc. Frontier Discoverer Drillship Chukchi Sea Exploration Drilling Program at 12 (Aug. 14, 2009) (hereafter "EPA Stmt of Basis"); *see also* 42 U.S.C. § 7627(a)(1) (EPA "shall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States . . . to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of part C of subchapter I of this chapter").
[9] *Id.* (internal citations omitted).
[10] Here the relevant NSR pollutants are CO, NOx, PM, $PM_{2.5}$, PM_{10}, SO_2, VOC, and CO_2.
[11] *See* 40 C.F.R. § 71.5(a)(1)(i).
[12] EPA Stmt of Basis at 13.
[13] 42 U.S.C. § 7475(a)(4).

Factual Background.

The communities along the North Slope of Alaska compared to many communities in the United States have fewer combustion sources.[14] While these communities are recipients of air pollution from other areas, they are relatively pristine areas. Shell has proposed a massive oil and gas exploration undertaking involving a drill ship, a fleet of support vessels including two ice breakers and aircraft traveling to and across the Arctic Ocean from July through October. Among the other known impacts associated with this action, the exploration activities will emit tons of health harming and climate changing pollutants into the air.

According to EPA's calculations, in a given year Shell's proposed operations would result in emissions that are equivalent to the following number of passenger vehicles driving 12,000 miles/year:

- For $PM_{2.5}$ the total project emissions are 184 tons/year. This is equivalent to 3,311,978 cars driving 12,000 miles per year.

- For PM_{10} the total project emissions are 210 tons/year. This is equivalent to 3,527,977 cars driving 12,000 miles per year.

- For SO_2 the total project emissions are 181 tons/year. This is equivalent to 2,042,315 cars driving 12,000 miles per year.

- For NOx the total project emissions are 1965 tons/year. This is equivalent to 211,916 cars driving 12,000 miles per year.

- For CO the total project emissions are 762 tons/year. This is equivalent to 3,336 cars driving 12,000 miles per year.[15]

These numbers demonstrate the significance of Shell's proposed operations on the fragile Arctic environment of the Chukchi Sea. The numbers assume that Shell's operations are stretched out over a full year, instead of the six or fewer months in which they will actually take place. Moreover, the calculations are for one year and not the three years or longer in which Shell will be operating.[16]

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[14] *See, e.g.*, EPA Stmt of Basis at 74 (noting that "Wainwright is a rural area with few combustion sources").

[15] EPA Region 10 Chukchi Q&A sheet received by NSB, August, 2009 (Appendix I).

[16] Shell is planning to drill two exploration wells in the Beaufort and three wells in the Chukchi Sea for 2010, but states that in a given year "two wells are to be drilled." Shell, Exploration Plan 2010 Exploration Drilling Program, OCS Lease Sale 193, Chukchi Sea, Alaska, Environmental Impact Analysis, at 285 (July, 2009) (hereafter "Shell EP EIA"). Shell thus is contemplating work in the Arctic that will last at least three years. *See, e.g.*, Shell EP EIA at 355 ("Shell is committed to a CAA process and will demonstrate this by making a good-faith effort to negotiate an agreement *every year it has planned activities*." (emphasis added)); Shell, Exploration Plan 2010 Exploration Drilling Program, OCS Lease Sale 193, Chukchi Sea, Alaska, Lease

Additionally, prior oil and gas operations have impacted air quality. As EPA notes, "[o]zone levels" and the levels of "ozone precursors (i.e., NOx and VOC)" in areas where "oil and gas operations are currently located" are "higher than the levels that have been collected at the Wainwright monitoring site."[17] Thus, demonstrating the impacts such operations can have.

Shell is proposing "to operate the Discoverer drillship and associated fleet in the Chukchi Sea" and seeks "a portable major source permit to allow for operation of the Discoverer and its associated fleet at" one or more of Shell's leases that it obtained during Lease Sale 193.[18] Shell is proposing a "maximum of 168 drilling days (5.5 months), beginning in July of each year" and "[d]rilling is planned to begin no earlier than July of 2010 and continue seasonally (i.e. July to December each year) until the resources under Shell's current leases are adequately defined."[19]

It is noteworthy that Shell is also currently proposing operations for the Beaufort Sea in 2010 during the same timeframe as its Chukchi Sea operations and the company owns many more leases in these areas. Thus, the overall, cumulative impacts of Shell's proposed and likely future operations on the air quality of the North Slope must be accounted for.

COMMENTS

I. EPA Needs To Address Carbon Dioxide And Other Greenhouse Gas Emissions In The Draft Permit.

Before issuing a PSD permit, the Clean Air Act requires that the EPA conduct a BACT analysis and include emissions limitations for "each pollutant subject to regulation" under the Act.[20] Carbon dioxide is a pollutant under the CAA,[21] and as described below is regulated under the Act and therefore needs to be included in the BACT analysis.

A. Shell Will Emit Significant Amounts of CO_2 and Other Greenhouse Gases That Must be Regulated as Part Of Shell's Permit.

The proposed permit for Shell's Chukchi Sea exploratory drilling program does not address carbon dioxide (CO_2) or other greenhouse gases (GHGs) to be emitted from the proposed OCS sources. However, greenhouse gas emissions from oil and gas sources can be significant. The Arctic has already witnessed temperature increases that are twice as large as global averages and is poised to continue warming temperatures at greater levels than the rest of the world.[22] The effects of global warming are acute in the Arctic where melting glaciers and rising sea levels

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Stipulations at 2 (July 2009) ("The lessee shall maintain a record of all personnel who attend the program onsite for so long as the site is active, *not to exceed 5 years*." (emphasis added)).

[17] EPA Stmt of Basis at 76.

[18] EPA Stmt of Basis at 5.

[19] *Id.* at 9.

[20] 42 U.S.C. § 7475(a)(4).

[21] *Massachusetts v. EPA*, 549 U.S. 497 (2007).

[22] *See* International Panel on Climate Change, Climate Change: 2007 Synthesis Report, at 30 (available at: http://www1.ipcc.ch/ipccreports/assessments-reports.htm).

threaten local species and coastal communities. In the Exploration Plan for the Chukchi exploration, Shell noted that the US Fish and Wildlife Service has recognized that climate change threatens the survival of marine mammals who depend upon sea ice.[23] Reducing greenhouse gas emissions is imperative to slowing and stopping these dramatic events from further harming the people and ecosystem of the Arctic.[24]

The Discoverer drillship and its associated support vessels will contribute large amounts of heat-trapping carbon dioxide, an estimated 20,000 tons, to the air each year from the Discoverer itself and about 55,000 tons per year from the Discoverer and its support vessels.[25] Its annual carbon dioxide emissions would be akin to the annual carbon dioxide emissions from 11,000 cars.[26] Marine diesel engines – such as those employed by Shell – when looked at cumulatively significantly degrade air quality, which is why there is an international agreement to reduce these emissions.[27]

Methane (CH_4) emissions will also result from vented sources during Shell's exploration drilling program. Methane is of particular concern as a greenhouse gas since it is over 20 times more effective at trapping heat in the atmosphere than carbon dioxide over the same 100-year period.[28] In fact, the CO_2 and CH_4 emissions from Shell's exploratory operations are hardly insignificant when considering the grave impacts to the Arctic Region from changes to the climate.

EPA has recognized the need for regulation of these emissions announcing on September 30, 2009 a proposal requiring large industrial facilities that emit at least 25,000 tons of greenhouse

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[23] Shell, Exploration Plan 2010 Exploration Drilling Program, OCS Lease Sale 193, Chukchi Sea, Alaska at 373 (July 2009) (hereafter "Shell 2010 Exploration Plan").

[24] In Shell's 2010 Exploration Plan the corporation highlights MMS's position that Shell's CO_2 emissions represent an "extremely small amount" of global greenhouse gases and thus the cumulative effects of Shell's CO_2 emissions are insubstantial. However, this position ignores the importance of incremental regulatory steps toward redressing harms caused by global warming. In *Massachusetts v. EPA*, the Supreme Court rejected the argument that mobile source emissions were such an insignificant amount of global greenhouse gases that regulation of those emissions could not redress the petitioners' injury from global warming because of the importance of incremental steps. 549 U.S. at 524-525.

[25] Shell EP EIA at 36.

[26] Based on EPA MOBILE6.2 fuel economy numbers, an average passenger vehicle emits approx. 5 metric tons of CO_2 equivalent per year. "Emission Facts: Greenhouse Gas Emissions from a Typical Passenger Vehicle", EPA420-F-05-004 February 2005 (available at: http://www.epa.gov/otaq/climate/420f05004.htm) (Appendix I).

[27] EPA, Program Announcement: International Maritime Organization Adopts Program to Control Air Emissions from Oceangoing Vessels (2008) (available at: http://www.epa.gov/oms/regs/nonroad/marine/ci/420f08033.pdf) (Appendix I).

[28] EPA Methane Information (available at: http://www.epa.gov/methane/index.html) (Appendix I) ("Methane is of particular concern as a greenhouse gas since it is over 20 times more effective at trapping heat in the atmosphere than carbon dioxide over the same 100-year period.").

gases a year to obtain construction and operating permits covering these emissions.[29] These permits must demonstrate the use of best available control technologies and energy efficiency measures to minimize greenhouse gas emissions. EPA has also finalized a rule to require mandatory reporting of greenhouse gas emissions, such as carbon dioxide, from "large sources" in the United States.[30] Under the rule, EPA proposes to require facilities that emit 25,000 metric tons or more per year of greenhouse gas emissions to submit annual reports to EPA. These reporting standards should apply to the current proposal because Shell is proposing to emit approximately 55,000 tons of CO_2 per year.[31]

EPA must regulate these significant CO_2 emissions from Shell's operations.[32] In Alaska, the oil and gas industry emits 15.3 million metric tons of CO_2 emissions each year.[33] By conducting CO_2 and GHG BACT analyses for Alaskan oil and gas sources that emit PSD thresholds of CO_2 and other GHGs, the agency could reduce a significant amount of these pollutants that are emitted. In doing so, the EPA would take an important step toward slowing the acute effects of global warming in the Arctic.

B. Carbon Dioxide is a Pollutant Subject to Regulation Under the CAA and Therefore Must be Included in Shell's Permit.

CO_2 and other greenhouse gases clearly fall within the Clean Air Act's definition of "air pollutant." The CAA defines "air pollutant" to include "*any* physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters the ambient air."[34] Further, the CAA specifically includes carbon dioxide in a list of "air pollutants." Section 103(g) of the CAA directs EPA to conduct a research program concerning "[i]mprovements in nonregulatory strategies and technologies for preventing or reducing multiple air pollutants, including . . . . . ***carbon dioxide***, from stationary sources, including fossil fuel power plants."[35]

EPA is required to regulate emissions of air pollutants, including carbon dioxide, under a number of the Clean Air Act's major substantive provisions, when, in EPA's judgment, such emissions cause or contribute to air pollution which "may reasonably be anticipated to endanger public health or welfare."[36] Examples include: section 111 establishing new source performance standards for categories of stationary sources; and section 202 establishing standards for emissions from new motor vehicles. EPA requires that major sources monitor, record, and report

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[29] *See* Fact Sheet -- Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (available at: http://www.epa.gov/NSR/fs20090930action.html) (Appendix II).
[30] *See* Background information on the Proposed Mandatory GHG Reporting Rule (available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html) (Appendix II).
[31] Shell EP EIA at 36.
[32] Shell EP EIA at 36.
[33] Shell EP EIA at 53.
[34] 42 U.S.C. § 7602(g) (emphasis added).
[35] 42 U.S.C. § 7403(g)(1) (emphasis added).
[36] 42 U. S. C. § 7521(a)(1).

emissions of CO_2 pursuant to section 821 of the CAA.[37] Further, the Act's definition of "welfare," specifically includes effects on "climate" and "weather."[38] Section 165(a)(2) of the CAA provides that a major emitting facility is "subject to the best available control technology for each pollutant subject to regulation under [the Clean Air Act] emitted from, or which results from, such facility."[39]

Additionally, EPA approved a State Implementation Plan ("SIP") revision for Delaware that includes actual emissions limitations of CO_2 for generators.[40] Moreover, EPA is currently in the process of increasing its regulations of CO_2 and other greenhouse gases. Recently, the EPA released a draft endangerment finding for CO_2 – *i.e.*, the first necessary step toward establishing NAAQS for a pollutant – and is taking public comment on how to manage CO_2 within the PSD program.[41] In conjunction with the National Highway Traffic Safety Administration, EPA has issued draft regulations to control greenhouse gas emissions from mobile sources.[42]

Recently, the Environmental Appeals Board (EAB) remanded two PSD permits where the permitting agencies failed to articulate a rationale basis for not conducting a BACT analysis for CO_2.[43] In both *Deseret* and *Northern Michigan*, the EAB determined that the permitting authorities had not provided sufficient information in the administrative record as to why a BACT analysis was not required for CO_2. In doing so, the EAB rejected the permitting authorities' arguments as to why CO_2 is not subject to regulation.

In *Deseret*, EPA Region 8 argued it was constrained by the historical agency interpretation that "subject to regulation" meant a pollutant had an actual emission limitation or control, which were not present in section 821's monitoring and reporting requirements. Region 8 also argued that section 821 is not actually part of the CAA because it was not written into the U.S. Code.[44] The

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[37] *See*, 40 C.F.R. § 75. Section 821 of Pub.L. 101-549 stated that: "(a) Monitoring.--The Administrator of the Environmental Protection Agency shall promulgate regulations within 18 months after the enactment of the Clean Air Act Amendments of 1990 to require that all affected sources subject to Title V of the Clean Air Act shall also monitor carbon dioxide emissions according to the same timetable as in section 511(b) and (c).

[38] 42 U.S.C. § 7602(h).

[39] 42 U.S.C. § 7475(a)(2).

[40] 73 Fed. Reg. 23101-23103 (April 29, 2008).

[41] Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 18886 (April 24, 2009); PSD: Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 Fed. Reg. 51535-51549 (Oct. 7, 2009).

[42] Proposed Rulemaking To Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, 74 Fed. Reg. 49453-49502 (Sept. 28, 2009).

[43] *See In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, 14 E.A.D. --- (Nov. 13, 2008); *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, 14 E.A.D. --- (Feb. 18, 2009).

[44] EPA is reconsidering its interpretation of this provision, *see* PSD: Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 Fed. Reg. 51535-51549 (Oct. 7, 2009).

EAB flatly rejected Region 8's argument, stating it was at odds with the agency's prior stance on section 821. In doing so, the EAB suggested that CO_2 is subject to regulation under section 821:

> the preamble as a whole augers in favor of a finding that the Agency expressly interpreted 'subject to regulation under this Act' to mean 'any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type.'[45]

The permitting agencies in *Deseret* and *Northern Michigan* could not provide an adequate explanation why CO_2 is not subject to regulation because there simply is not one. Between section 821 of the CAA and Delaware's emissions limitations on electrical generators, CO_2 is definitively regulated under the CAA and must be subject to a case-by-case BACT analysis for new sources that will emit the pollutant in significant amounts. In the absence of a BACT analysis for Shell's operations, the EPA must provide a legally defensible justification as to why CO_2 is not subject to regulation under the Act.

II. BACT Must Be Applied To All The Vessels And Emission Units That Shell Intends To Use In Order To Ensure Compliance With The Clean Air Act.

The Clean Air Act requires Best Available Control Technology (BACT) for both the Discoverer, an OCS source, and its support vessels. Thus, before issuing a Prevention of Significant Deterioration (PSD) permit to a major new stationary source (source), the EPA must conduct a BACT analysis for each pollutant that the source has the potential to emit in significant quantities.[46]

In the draft PSD permit for Shell's Chukchi operations, BACT has been applied to select emission units on-board the Discoverer and to the support vessel only while it is attached to the Discoverer. BACT has not been required for the Discoverer's propulsion engine or the other numerous vessels that are associated with Shell's proposed operations (hereafter ancillary fleet or ancillary vessels). These vessels include two icebreakers, a resupply ship, and an oil response fleet (composed of one offshore management ship and three 34-foot work boats). This is significant because the ancillary vessels account for at least 97 percent of Shell's overall emissions for five of the criteria air pollutants and the emissions from Discoverer's propulsion engine have yet to be calculated.[47]

The ancillary vessels and Discoverer's propulsion engine must be regulated as part of the emissions from the "OCS source." Issuing a permit that fails to require BACT for these vessels

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[45] *In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, Slip Op. at 3.
[46] 42 U.S.C. § 7475(a)(4).
[47] *See*, Appendix A, EPA Stmt of Basis at A-1: Summary of Annual Emissions for the Discoverer and the Associated Fleets. (*i.e.*, the Discoverer is projected to emit 52.34 tons/year of NOx while the associated fleet is projected to emit 1,912.29 tons/year of NOx. Overall, Shell's operations will emit 1964.63 tons/year of NOx, of which the associated fleet is responsible for 97.3%)

and engines would result in violations of section 328 of the CAA, contravene Congress's clear intention to regulate the emissions from vessels associated with drill ship exploration, would be counter to the goals of the PSD program which include protecting public health and welfare, and areas of "regional natural" value,[48] and a misapplication of 40 C.F.R. § 55.2. As discussed below, BACT needs to be applied to the ancillary vessels and Discoverer's propulsion engine.

A. Shell's Ancillary Vessels Supporting the OCS Source (the Discoverer) are Considered Direct Emissions From the Discoverer for Purposes Of BACT Regulation.

In section 328 of the Clean Air Act, Congress directed EPA to promulgate regulations to control air pollution over the Outer Continental Shelf (OCS) and provided a broad definition of OCS source:

> The terms "Outer Continental Shelf source" and "OCS source" include any equipment, activity, or facility which--
>
> (i) emits or has the potential to emit any air pollutant,
>
> (ii) is regulated or authorized under the Outer Continental Shelf Lands Act (43 U.S.C.A. § 1331 et seq.], and
>
> (iii) is located on the Outer Continental Shelf or in or on waters above the Outer Continental Shelf.
>
> Such activities include, but are not limited to, platform and drill ship exploration, construction, development, production, processing, and transportation. For purposes of this subsection, emissions from any vessel servicing or associated with an OCS source, including emissions while at the OCS source or en route to or from the OCS source within 25 miles of the OCS source, shall be considered direct emissions from the OCS source.[49]

The Conference Report accompanying this provision explains:

> Marine vessels emissions, including those from crew and supply boats, construction barges, tugboats, and tankers, which are associated with an OCS activity, will be included as part of the OCS facility emissions *for the purposes of regulation.* Air emissions associated with stationary and in-transit activities of the vessels will be included as part of the facility's emissions for vessel activities within a radius of 25 miles of the exploration, construction, development or production location. This *will ensure* that *the cruising emissions from marine*

[48] 42 U.S.C. § 7470.
[49] 42 U.S.C. § 7627(a)(4)(C).

> *vessels are controlled and offset as if they were part of the OCS facility's emissions.*[50]

Thus, the legislative history evinces Congress's intent to count marine vessel emissions as direct emissions from an OCS source not solely for the purposes of a potential to emit calculation, but also for the "purposes of regulation." The Senate Report confirms Congress's intent to regulate emissions from vessels:

> [A]ll emissions from marine vessels (including engine emissions) which service or are associated with an OCS source, are subject to the same permitting, enforcement, monitoring, reporting, and offset requirements which would apply if these vessels were located in the corresponding onshore (State waters) area. This is intended to include emissions generated while vessels are traveling within the same air basin. These requirements should apply to vessel emissions occurring while at the OCS source, or when enroute to or from the OCS source and to or from the corresponding onshore area.[51]

Despite the clear statutory language of the CAA and intent of Congress, the emissions from Shell's ancillary vessels are not being controlled.

The Discoverer clearly meets the definition of an "OCS source" under section 328 of the Act. In order to be subject to the PSD program, the emissions from the Discoverer's engines (minus the propulsion engine) *and* the ancillary vessels were added together and Shell's operations were determined to be a "major source" and thus, subject to regulation under the PSD program.[52] However, when it came time to apply control technologies to Shell's operations, the ancillary vessels (aside from the supply vessel when it is attached to Discoverer) were excluded.

Application of BACT to all the ancillary vessel and propulsion engine emissions is necessary because they are "emissions from [] vessel[s] servicing or associated with an OCS source,"[53] here the Discoverer, "including emissions while at the OCS source"[54] and such emissions "shall be considered direct emissions from the OCS source."[55] These emissions "will be included as part of the OCS facility emissions *for the purposes of regulation*."[56] Therefore, since Shell's ancillary vessels are associated with the Discoverer (irrespective of whether they are OCS sources in and of themselves), they are to be considered for regulatory purposes as direct

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[50] 136 Cong. Rec. S16895-01 (Oct. 27, 1990) (emphasis added).
[51] S. Rep. 101-228, 1990 U.S.C.C.A.N. 3385 (Dec. 20, 1989).
[52] *See* Appendix A, EPA Stmt of Basis at A-1. The supporting vessels will emit the following percentages of the total projected project emissions for each criteria pollutant: 98% of CO, 97% of NOx, 97% of $PM_{2.5}$, 98% of PM_{10}, 99.8% of VOC, and 85.7% of lead. Shell estimated that the ancillary vessels have the potential to emit significant amounts of criteria pollutants in an overwhelmingly greater amount than the Discoverer.
[53] 42 U.S.C. § 7627(a)(4)(C).
[54] 42 U.S.C. § 7627(a)(4)(C).
[55] 42 U.S.C. § 7627(a)(4)(C).
[56] 136 Cong. Rec. S16895-01 (Oct. 27, 1990) (emphasis added).

emissions from the source.[57] The statutory definition of "OCS source" does not exempt any activities or parts of an OCS source from the control technologies requirements.[58]

Presumably BACT was not applied to the ancillary vessels based on EPA's application of its regulatory definition of "OCS source,"[59] to Shell's proposed operations. The regulatory definition as applied here violates the plain language of the statute.[60]

B. EPA's Interpretation of OCS Source is Inconsistent with Its Implementation of the PSD Program.

The EPA's application of the term "OCS source" in Shell's permit is also inconsistent with the agency's administration of the PSD program as a whole. In its PSD regulations, EPA defined a "stationary source" – *i.e.*, one that is subject to regulation under the program – as "any building, structure, facility, or installation," which in turn is defined as "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)."[61]

This is an incredibly broad interpretation of the activities that are covered under the PSD program. Indeed, the EPA has determined that facilities a mile or more apart are the same source for purposes of the PSD program.[62] Therefore, it is arbitrary for EPA on the one hand to implement the PSD program broadly on-shore, while narrowing the same program significantly when the activities are occurring offshore. This interpretation is also contrary to Congressional intent that OCS sources comply with the same requirements as non-OCS sources.[63]

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[57] We also point out that the ancillary vessels are authorized under the Outer Continental Shelf Lands Act (OCSLA) because Minerals Management Service (MMS) must approve Shell's exploration plan and issue a permit to commence exploration before Shell's operations – which the supporting vessels are an essential part of – can commence. *See* 43 U.S.C. § 1340(b).

[58] 42 U.S.C. § 7627(a)(4)(C).

[59] *See* 40 C.F.R. § 55.2.

[60] *See* 42 U.S.C. § 7627(a)(4)(C).

[61] 40 C.F.R. § 52.21.

[62] *See* EPA, Memorandum from Douglas E. Hardesty to Robert R. Robichaud, Re: Forest Oil Kustatan Facility and Osprey Platform Construction Permitting Applicabilitv Determination (Aug. 21, 2001) (Appendix II) (2.8 miles); EPA, Memorandum from Director to Clyde B. Eller, Re: Shell Oil Company Wilmington Complex Specification of "Source" (May 16, 1980) (Appendix II).

[63] *See* Senate Report 101-228, 1990 U.S.C.C.A.N. 3385, 3463 (December 20, 1989) (explaining that "[t]his section of the bill is intended to ensure that air pollution from OCS activities does not degrade the air quality in coastal regions of the United States. This is to be achieved by applying the same air quality protection requirements as would apply if the OCS sources were located within the corresponding onshore area.")

C. BACT Must also Be Applied to the Discoverer's Propulsion Engine.

OCS sources are subject to PSD permitting requirements, including BACT.[64] Nevertheless, BACT is not being applied to the propulsion engine on the Discoverer.[65] This is critical because the propulsion engine is a major contributor of air pollutants given its size (7,200 horse power engine). For example, Shell estimates that bringing the Discoverer into and out of the 25-mile radius of a drill site would result in the addition of half a ton of NOx to Shell's overall emissions.[66] By exempting the propulsion engine from regulation as an OCS source, EPA has ignored its duty to control air pollution on the OCS in a manner to "attain and maintain Federal and State ambient air quality standards."[67] Without including the Discoverer's propulsion engine in the potential to emit (PTE) calculation, EPA cannot guarantee that Shell's drill ship exploration will not violate the NAAQS. EPA must include the propulsion engine within the PTE calculation and conduct a BACT analysis for it.

Congress intended to regulate drill ship exploration that has the potential to emit air pollutants, is authorized by OCSLA, and is "in or on waters above the Outer Continental Shelf."[68] The propulsion engine on the Discoverer is intrinsic to its operations and will transport the ship within the 25-mile radius surrounding the drill site when Shell is moving on to and off the site and moving between lease blocks.[69] Shell's application also states that the rig may need to leave the drill-site and return due to adverse ice conditions or other factors.[70] Thus, the statutory definition of OCS source includes the Discover's propulsion engine as the ship moves within the 25-mile radius of the drill site.

The legislative history of section 328 explains that:

> Air emissions associated with stationary and *in-transit activities* of the vessels will be included as part of the facility's emissions for vessel activities *within a radius of 25 miles of the exploration, construction, development or production location*. This will ensure that the cruising emissions from marine vessels are *controlled and offset* as if they were part of the OCS facility's emissions.[71]

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[64] 40 C.F.R. § 55.13(d).
[65] EPA Stmt of Basis at 26.
[66] *Id.*
[67] 42 U.S.C. § 7627(a)(1).
[68] 42 U.S.C. § 7627(a)(4)(C).
[69] *See* Air Sciences, Outer Continental Shelf Pre-Construction Air Permit Application Revised Frontier Discoverer Chukchi Sea Exploration Drilling Program Prepared for Shell Offshore Inc. at 25 (Feb. 2009) (hereafter "Shell Revised OCS App.") (The potential to emit does not include "the Discoverer propulsion emissions for the approximate four hours of time to bring the Discoverer the final 25 miles to the drill site and move it away").
[70] Shell Revised OCS App. at 4.
[71] *See* 136 Cong. Rec. S16895-01 (Oct. 27, 1990) (emphasis added). In addition, Congress explicitly listed drill ship exploration as an example of an activity that falls within the definition of OCS source. Drill ship exploration inherently includes the use of propulsion engines for reaching the drill site and maneuvering to place the ship's anchors.

However, when EPA promulgated the OCS CAA regulations at 40 C.F.R § 55.2, EPA replaced Congress's inclusive definition of "OCS source" with an exclusive one:

> OCS source *means* any equipment, activity, or facility which:
>
> (1) Emits of has the potential to emit any air pollutant;
> (2) Is regulated or authorized under the Outer Continental Shelf Lands Act ("OCSLA") (43 U.S.C. § 1331 et seq.); and
> (3) Is located on the OCS or in or on waters above the OCS.
>
> This definition shall include vessels *only* when they are:
>
> (1) Permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing, or producing resources therefrom, within the meaning of section 4(a)(1) of OCSLA (43 U.S.C. § 1331 et seq.); or
>
> (2) Physically attached to an OCS facility, in which case only the stationary sources aspects of the vessels will be regulated.[72]

Because Congress provided an inclusive definition of "OCS source," EPA did not have the discretion to re-define and narrow Congress's definition.

When Congress uses inclusive language in a statutory definition, the definition is unambiguous and EPA cannot restrict that definition through a regulatory interpretation.[73] In *Massachusetts*, the Supreme Court rejected EPA's reading of the CAA definition of "air pollutant" to exclude carbon dioxide because the statutory definition of "air pollutant" is unambiguous. In finding the statutory text unambiguous, the Supreme Court emphasized the "sweeping" language in the definition of "air pollutant": "includes any." Because the statute was unambiguous and sweeping, the Supreme Court rejected EPA's attempt to exclude carbon dioxide by relying on post-Congressional enactments.[74] As in *Massachusetts*, EPA's regulatory definition of "OCS source" has impermissibly narrowed an unambiguous definition. In section 328, Congress provided a similarly "sweeping" definition of "OCS source" by using the expansive language "includes any."[75] Thus, Congress's definition of "OCS source" is unambiguous and EPA did not have the authority to interpret and restrict that definition as only applying to vessels in limited instances.

Furthermore, Congress provided that equipment *authorized* under the OCSLA, and not just *regulated* under the OCSLA, would be defined as an OCS source under the CAA. Vessels authorized under OCSLA include not only those attached to the seabed but also those involved

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[72] 40 C.F.R § 55.2.
[73] *See Massachusetts v. EPA*, 549 U.S. at 528-529 (stating that the CAA definition of "air pollutant" is unambiguous because Congress used inclusive language).
[74] *Id.*
[75] 42 U.S.C. § 7627(a)(4)(C).

with exploration, development, and production.[76] Those activities, as defined under OCSLA, require a number of vessels that are *never* attached to the seabed. For example, "exploration" includes seismic testing with ships,[77] "development" includes "geophysical activity,"[78] and "production" includes "transfer of minerals to shore."[79]

Thus, EPA impermissibly excluded an entire category of unattached vessels that are authorized under the OCSLA – *i.e.*, all the equipment and activities that are authorized under the OCSLA but are not attached to the seabed. In the preamble to the regulatory definition of "OCS source," EPA explains why it chose to require that vessels be attached to the seabed:

> Section 328(a)(4)(C)(ii) defines an OCS source as a source that is, among other things, regulated or authorized under the OCSLA. The OCSLA in turn provides that the Department of the Interior ("DOI") may regulate "all installations and other devices permanently or temporarily attached to the seabed, which may be erected thereon for the purpose of exploring, developing, or producing resources therefrom, or any such installation or other device (other than a ship or vessel) for the purpose of transporting such resources." 43 U.S.C. § 1333(a)(1). Vessels therefore will be included in the definition of "OCS source" when they are "permanently or temporarily attached to the seabed" and are being used "for the purpose of exploring, developing or producing resources therefrom."[80]

The preamble highlights that EPA developed the requirement that vessels be attached to the seabed because of its (mistaken belief) that DOI only has the authority to *regulate* attached vessels under the OCSLA. OCSLA negates this.

Presumably, the Discoverer's propulsion engine is not being regulated based on Shell's assertion that "the propulsion engine will be shut down prior to placement of the first anchor and turned back on only after removal of the final anchor."[81] We request that EPA consult with the US Coast Guard (USCG) to determine if it is safe to completely shut-down the Discoverer's propulsion engine while setting anchors, especially in rough sea conditions. Shell's application states that once the Discoverer arrives at the drill site, the propulsion unit will be shutdown prior to setting the first anchor and that the drillship will be anchored and kept in position by support vessels during the entire time at the drill site, up to and including removal of the last anchor.[82]

Typically large vessel propulsion engines continue to operate while anchors are set and are started prior to releasing anchors, this way the captain has full control of the vessel while anchors are set and released. Setting a large drillship adrift in heavy ice conditions without an operational propulsion systems does not appear to be a safe plan.

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[76] 42 U.S.C. § 7627(a)(4)(C).
[77] 43 U.S.C. § 1331(k).
[78] 43 U.S.C. § 1331(l).
[79] 43 U.S.C. § 1331(m).
[80] 57 Fed. Reg. 40792, 40793 (Sept. 4, 1992).
[81] *Id*.
[82] Shell Revised OCS App. at 6.

Indeed, both Shell and EPA acknowledge in discussing ice management that "it is important that the Discoverer's bow be facing into the wind (+/- 15 degrees) so that any oncoming ice will contact the Discoverer only on the bow."[83] While a turret and hydraulic jacks (powered by the ship's main generators) help Discoverer maintain this position once it is anchored, neither Shell nor EPA explain how Discoverer will keep its bow facing the wind while the ship is being anchored.

Of note, Shell's 2007 Air Permit Application for the Discoverer[84] stated that the propulsion engines on the Frontier Discoverer would be operated during anchoring:

> The emissions from propulsion engines on the Frontier Discoverer and the Jim Kilabuk are not considered in the assessment, since *these propulsion engines will be used very briefly to maneuver the Frontier Discoverer when it is being anchored* or to maneuver the Jim Kilabuk when it is near the Frontier Discoverer drill rig.[85]

We ask that Shell be required to provide more information on its station-keeping operations for the drillship while at the drillsite. Shell does not explain its method for station-keeping during adverse weather conditions at the drill site. Please clarify whether the drillship propulsion engines are required to support station-keeping operations. Also, please verify Shell's station-keeping plans and consult with USCG on this topic. If the Discoverer propulsion engines are required for safe anchoring and sea-keeping at the drill site, then those emissions should be included in the source's potential to emit (PTE) and BACT should be applied.

III. The EPA Failed To Make An Adequate BACT Determination.

For all sources subject to BACT, EPA must establish an "emission limitation based on the maximum degree of reduction" for each pollutant that the source will emit in significant quantities.[86] To determine the appropriate emission limitation, the EPA may take into account, "energy, environmental, and economic impacts and other costs."[87] In doing so, the EPA must adequately justify and explain its decision to eliminate control technologies due to technical infeasibility or collateral impacts.[88]

In applying BACT here, EPA utilized the top-down approach.[89] As EPA explained in its New Source Review Workshop Manual:

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[83] EPA Stmt of Basis at 36.
[84] Appendix D to Shell 2010 EP, at 13.
[85] Appendix D to Shell 2010 EP, at 13 (emphasis added).
[86] 42 U.S.C. § 7479(3).
[87] *Id.*
[88] *In re: Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 131 (Feb. 4, 1999) (remanding a PSD permit to the permitting agency).
[89] *See* EPA, New Source Review Workshop Manual (1990) (available at: http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf).

> the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.[90]

Thus, BACT requires that EPA do more than summarily dismiss technologies and instead provide "a clearly ascertainable basis for a conclusion."[91] In *Knauf Fiber Glass*, the Environmental Appeals Board was unable to ascertain whether a PSD permit included the best available control technology for the source because the permitting authority did not provide proper documentation of the potential control technologies and a technical feasibility analysis. The EAB required the permitting authority to conduct a supplemental BACT analysis that included a list of control options, an explanation of the technical feasibility analysis, and justifications for eliminating control options.[92]

In Shell's draft permit, EPA purports to have set BACT for all required sources. While BACT has purportedly been required for all the necessary sources, in reality only certain sources are receiving certain controls. A rigorous analysis must be undertaken to arrive at BACT for *all* required sources. In situations like this, the EAB has emphasized that an agency's less than rigorous analysis is not BACT:

> If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.[93]

In Shell's draft permit, EPA failed to meet the rigorous BACT demands because the agency did not: (1) take into account that this is the first major source permit for an OCS source; (2) identify all available control technologies; (3) adequately support its decision to eliminate the best available control technology for several engines and pollutants; and (4) conduct BACT for the propulsion engines and ancillary vessels.

A. There are Overarching Problems with the BACT Analysis.

The efforts to apply BACT for conventional industrial sources to Shell's OCS operations has failed to result in appropriate controls being applied to Shell's operations. As the EAB has

[90] *Id.* at B.2.
[91] *In re: Knauf Fiber Glass*, 8 E.A.D. at 134.
[92] *Id.*
[93] *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, Slip Op. at 16, 14 E.A.D. --- (EAB Feb. 18, 2009).

explained "BACT is [] a site-specific determination that results in the selection of an emission limitation representing application of control technology or methods appropriate for the particular facility."[94] As Shell recognized, "OCS exploratory drilling operation is substantially different than the industrial sources typically addressed by the PSD permit process . . . ."[95] This is precisely why it is imperative that Shell and EPA think outside the box in applying BACT to the engines on the Discoverer and why BACT for conventional industrial sources cannot serve as the universe of "all available control technologies" for Shell's operations.

Additionally, there are many aspects of Shell's proposed operations that are being "regulated" by good control practices rather than the application of new control technologies or retrofits.[96] Shell rationalizes its proposed use of good control practices by explaining that while the Discoverer is considered a new source, it has old engines on board that do not "fit" well within the "typical permit process."[97] The fact that Shell has elected to pursue its operations using an old drill ship – rather than incurring the cost of utilizing or constructing a new one – cannot result in the automatic conclusion that retrofitting or replacing certain engines as part of the application of BACT is not economical or technologically feasible.[98] This is not defensible without at least a discussion of the costs associated with using the Discoverer versus a newer or newly constructed drill ship and/or engines as compared to the costs of retrofitting or updating engines on the Discoverer.

B. Step One of the BACT Analysis for Shell's Proposed Operations is Inadequate.

The first step of the BACT analysis for Shell's operations is inadequate. As the EAB has explained, "[t]he first step of the top-down methodology is to "identify, for the emissions unit in question . . . *all 'available' control options*."[99] However, EPA in several instances has simply accepted Shell's list of possible control options and failed to explain that "all available control options" were considered and what those options would be for each engine.[100]

In as much as EPA goes beyond the list of possible control technologies provided by Shell, it fails to explain how it learned of these technologies and whether there are other control options

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[94] *In re: Desert Rock Energy Company LLC,* Slip Op. at 52 (*citing In re Prairie State Generating Co.*, PSD Appeal No. 05-05, Slip Op. at 15 (EAB Aug. 24, 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007)).
[95] Shell Revised OCS App. at 29.
[96] *See e.g.*, EPA Stmt of Basis at 50 ("BACT for NOx for the smaller diesel IC engines [is] the good combustion practice of operating and maintaining the engines according to the manufacturer's recommendations"); *see also* Appendix A.
[97] Shell Revised OCS App. at 29.
[98] *See e.g.*, EPA Stmt of Basis at 55 ("Tier 2 or Tier 3 level controls are intrinsic to the original engine design; and, therefore, are not considered technically feasible in this case since they are not part of the design of the existing Caterpillar D399 diesel engines.").
[99] *In re ConocoPhillips Co.*, PSD Appeal No. 07-02, Slip Op. at 28, 13 E.A.D. --- (EAB June 2, 2008) (quoting NSR Manual at B.5) (emphasis added).
[100] *See, e.g.*, EPA Stmt of Basis at 42.

available. For example, in discussing possible control technologies for PM emissions from diesel fired boilers EPA notes that "[a]lthough not found in the previous determinations listed in the RBLC and CA-BACT, PM control technologies such as an electrostatic precipitator (ESP) or a fabric filter could theoretically be designed for the small boilers on Discoverer."[101] Shell's use of only two databases to search for control technologies is also insufficient.

EPA must look beyond the RACT/BACT/LAER Clearinghouse (RBLC) to determine BACT for Shell's sources. The RBLC includes "case-specific information on the 'Best Available' air pollution technologies that *have been required* to reduce the emission of air pollutants from stationary sources (e.g., power plants, steel mills, chemical plants, etc.)."[102] As the RBLC includes technologies from past BACT determinations, it is unlikely to have control technologies that are applicable to Shell's sources because this is the first major source permit for an OCS source. The lack of readily applicable control technologies in the RBLC does not excuse EPA from exploring alternative sources of control technologies. The EAB has emphasized that a proper BACT analysis should consider technologies outside the U.S. and "existing controls applied to similar sources other than the category in question."[103] In this permit, EPA must look outside the RBLC database to find available control technologies because BACT is meant to "promote use of the best control technologies as widely as possible."[104]

1. Additional control technologies that should have been considered.

Given the nature of Shell's operations, additional control technologies should have been considered in step-one of the BACT analysis. We ask that EPA consider the following controls and explain why they are (or are not) applicable to Shell's operations.

Repowering. For the Generator Diesel IC Engines and the smaller Diesel IC Engines, EPA states that Tier 2 or 3 level controls are technologically infeasible because those controls are intrinsic to the original engine.[105] In eliminating Tier 2 or 3 controls, EPA fails to provide any factual support that it is technologically infeasible to repower the Discoverer with new Tier 2 or 3 engines.

Repowering ships with new engines is a technologically feasible control option. In a 2007 air emissions report, the Port of Los Angles found that 27% of all main engines and 42% of all auxiliary engines were replacements of older engines in harbor craft operating in the Port during 2007.[106] The Casco Bay Island Transit District repowered a ferry with Tier II engines.[107] Thus, replacement of both auxiliary and main engines is technically feasible on a variety of other marine vessels. Because other marine vessels are a similar source category to the Discoverer and

[101] EPA Stmt of Basis at 55.
[102] *See* http://cfpub.epa.gov/RBLC/htm/bl02.cfm (emphasis added) (Appendix III).
[103] *In re: Conophillips, Co.*, Slip Op. at 29.
[104] *In re: Knauf*, 8 E.A.D. at 140.
[105] EPA Stmt of Basis at 55 and 58.
[106] *See* Port of Los Angeles, Inventory of Air Emissions 2007, Technical Report: December 2008. at 95-96 (Appendix III).
[107] *See* www.maine.gov/dep/blwq/topic/vessel/airemissionsreport.pdf (Appendix III).

auxiliary vessels, EPA must determine whether repowering engines is also technologically feasible on the Discoverer and auxiliary vessels.

EPA cannot assume that Tier 2 or 3 controls are not technically feasible because they are cost prohibitive. By upgrading to newer engines, Shell may save money through fuel efficiency and future emission control requirements. When the Catalina Express successfully repowered four main engines and generators to reduce NOx and PM emissions, the operator received a fuel savings of almost $400,000 per year.[108] The Catalina is a similar source because it has four engines that are comparable to the Discoverer's engines: Caterpillar 3512B engines that are rated at 1950 hp.[109] The Catalina was successful in replacing engines and generators, showing that replacement of similarly-sized engines and generators on the Discoverer is technologically feasible.

Re-Tooling. If Shell is unwilling to consider re-powering its engines, then re-tooling is also an available option that was not adequately discussed in the BACT analysis. For example, Clean Clam Technology Systems provides kits for re-tooling conventional diesel engines.[110] The Navy used such kits in conjunction with DFPs and low sulfur fuel to reduce its emissions on "a U.S. Navy work boat/barge."[111]

SCR Controls. Shell proposes using SCR controls for the generator engines on the Discoverer,[112] but rejects this same control for the compressor's diesel engines.[113] The primary reason SCR controls are rejected as BACT is space limitations on board the Discoverer. However, neither Shell nor EPA discuss potential ways in which additional space can be made on board the Discoverer for control technologies or whether there are ways to funnel the emissions from several engines through one SCR system to save on space. We ask that EPA provide explanations on both of these fronts.

Hydrocarbon SCR or Lean De-NOx Catalysts. Shell and EPA should consider use of hydrocarbon SCR or Lean De-NOx Catalysts to control NOx emissions. British companies including the Association for Emissions Control by Catalyst and Johnson Matthey Catalysts manufacture such systems and the advantage is that because the system is based around hydrocarbons (instead of urea) the hydrocarbons can be introduced from the exhaust itself.[114]

NOx Absorbers/NOx Traps. Another available technology is the NOx absorber or trap which in conjunction with low sulfur fuel absorbs and stores NOx.[115]

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[108] *See* http://www.dgtww-digital.com/dgtww/200812/?pg=16 (Appendix III).
[109] http://www.catalinaexpress.com/catalinaJet.php (Appendix III).
[110] *See* http://www.cctskit.com/tech.html (Appendix III).
[111] MECA, Locomotive and marine case studies (Appendix III).
[112] *See* EPA Stmt of Basis at 47.
[113] *Id.* at 48.
[114] *See* http://www.aecc.eu/en/Technology/Catalysts.html#Hydrocarbon_SCR; http://ect.jm catalysts.com/site.asp?siteid=833&pageid=866 (Appendix III).
[115] *See* http://www.aecc.eu/en/ Technology/Adsorbers.html (Appendix III).

Diesel Particulate Filters. For those engines that are not Tier 3 and that are not receiving either OxyCat controls or CDPF technology, we recommend that Shell apply some form of diesel particulate filter. Johnson Matthey Catalysts has developed a line of such filters that offer "flexibility to the user."[116] The California Environmental Protection Agency's Air Resources Board has a list of currently verified technologies that include several examples of DPFs that are able to achieve an 85% emission reduction in PM levels.[117]

C. The Other Steps in The BACT Analysis for Shell's Operations are also Inadequate.

In the Statement of Basis, EPA makes conclusory statements that certain technologies are technologically infeasible without providing adequate support. For example, EPA determined that CDPF is not "technically feasible" for application to the Generator and Smaller Diesel Engines because it is not "commercially available."[118] The only support that EPA provides is a single opinion: "DEC Marine stated that they are not aware of any applications of CDPF systems on older heavy marine engines."[119] That one company is unaware of a particular technology hardly supports a bold statement that a control technology is commercially unavailable. EPA must look beyond this single opinion and provide addition support for its conclusion that CDPF is technically infeasible.

Other problems with Shell's BACT analysis include:

- EPA did not provide factual support for its decision not to set a BACT emission standard for the crankcase ventilation on the Generator Diesel IC Engines because "quantifying PM emissions from crankcase ventilation is difficult and makes the imposition of an emission standard for the crankcase ventilation infeasible."[120] Difficulty does not equate to infeasibility.

- EPA failed to adequately explain why the imposition of CDPF or an OxyCat system to the Compressor Diesel IC Engines is cost-ineffective. EPA mentions that the cost effectiveness of installing a CDPF would exceed $100,000 per ton of PM removed and references a cost effectiveness estimation calculation in Appendix C of Shell's permit application.[121] But the cost effectiveness table does not provide a meaningful explanation for why $100,000 per ton of PM is cost-ineffective. If the high cost of CDPF is associated with an up-front installation cost, EPA should consider the multiple trips that Shell has planned for the Discoverer under this permit, let alone the multiple trips it is likely to take on other oil exploration trips, including the concurrently proposed Beaufort exploration plan. Moreover, after suggesting that OxyCat "could be possible,"

[116] *See* http://ect.jmcatalysts.com/site.asp?siteid=833 &pageid=868 (Appendix III).
[117] *See* http://www.arb.ca.gov/diesel/verdev/vt/cvt.htm (Appendix III).
[118] *See* EPA Stmt of Basis at 56 and 59.
[119] *Id.*
[120] *See Id.* at 57.
[121] *See Id.*

EPA completely failed to mention why OxyCat is cost-ineffective or otherwise infeasible before eliminating it as a potential control technology.[122]

- EPA failed to explain how it concluded that designing an ESP or a fabric filter for small boilers is technically infeasible.[123] EPA states that this technology "may be theoretically possible" but simply says that the control technologies are not found in practice.

D. The Proposed Best Available Control Technology (BACT) Emission Limits Fail to Reflect the Maximum Level of Control that Can be Achieved.

1. Critique of the NO_x BACT analysis for MLC compressor engines.

EPA is proposing that BACT for the diesel mud line cellar (MLC) compressor engines is the EPA Tier 3 emission standard of 4.0 g/kWh NO_x + NMHC.[124] EPA has accepted the same BACT limit that Shell proposed in its application.[125] EPA eliminated all other control options as technically infeasible. According to the discussion in EPA's draft permit, the MLC compressor engines are new and will already incorporate exhaust gas recirculation (EGR) and intake air cooling (AC) technologies in order to meet EPA Tier 3 emissions standards.

EPA further claims that injection timing retard (ITR), a high injection pressure (HIP) fuel system and low NO_x design (LND) technologies are therefore incompatible with these engines. EPA also ruled out water injection (WI) as a feasible control option due to various technical constraints. However, the use of selective catalytic reduction (SCR) as an add-on control for these MLC compressor engines was dismissed due to a need for portability for these engines and due to space limitations.[126] We do not agree that these limitations preclude the use of SCR for the MLC compressor engines. In fact, SCR has been required as BACT in portable applications and is commercially demonstrated as an add-on control technology for nonroad engines.

Specifically, Chevron Products Company was recently issued a PSD permit for a portable crude generator requiring the use of selective catalytic reduction of NO_x emissions to meet a 1.3 pound per hour emission limit.[127] This engine is permitted as a large engine (> 500 hp), similar in size category to the MLC compressor engines (which are 540 hp each). Shell's application materials included Chevron's BACT determination so both EPA and Shell were aware that this technology was feasible on a similar source.[128] More generally, however, the commercially demonstrated application of SCR technology to non-road engines supports the use of this technology for

[122] *See* EPA Stmt of Basis at 57-58.
[123] *See Id.* at 59.
[124] *See Id.* at 49; Region 10 EPA, draft OCS PSD Permit for Shell Chukchi Sea Operations at Condition F.1.1.
[125] *See*, Shell Revised OCS App. at 38.
[126] *See* EPA Stmt of Basis at 48.
[127] EPA's RACT/BACT/LAER Clearinghouse, MS-0086, Chevron Products Company, Pascagoula Refinery, Permit No. 1280-00058, May 8, 2007.
[128] *See* Shell Revised OCS App., Appendix C at 4.

portable applications and, therefore, EPA must consider it as a technically feasible option in the BACT analysis for the MLC compressor engines.

The Manufacturers of Emission Controls Association (MECA), a non-profit association that provides technical information on emission control technology and has a goal of "facilitating the establishment of strong and effective state, federal, and international air quality programs that promote public health, environmental quality, and industrial progress," stated that:

> Hundreds of SCR retrofit systems have been installed in the U.S. and Europe on large highway trucks since 1995. Operating experience exceeding 350,000 miles has been generated on some vehicles. SCR-equipped trucks using a urea-based reductant are now commercially available in Europe where tens of thousands of units are operating on the roads to comply with Euro 4 and Euro 5 heavy-duty engine emission regulations. SCR is expected to be introduced on diesel passenger cars and heavy-duty trucks operating in the U.S. over the next three years [from 2006-2009] to comply with EPA's Tier 2 light-duty regulations and EPA's 2010 heavy-duty highway diesel emission regulations. These mobile source SCR systems can be designed to give significant reductions in NOx (75-90%), as well as reductions in HC (80%) and PM (20-30 %) emissions.[129]

Furthermore, in MECA's written testimony on EPA's proposed standards of performance for stationary compression ignition internal combustion engines, it stated:

> [s]ince the mid-1990s, SCR technology using a urea-based reductant has been installed on a variety of marine applications in Europe including ferries, cargo vessels, and tugboats with over 100 systems installed on engines ranging from 450 to 10,200 kilowatts (kW). These marine SCR applications include the design and integration of systems on a vessel's main propulsion engines and auxiliary engines.[130]

EPA's Diesel Retrofit Technology Verification program confirms that SCR is a proven technology for stationary engine applications and is commercially demonstrated for mobile applications.[131] Several manufacturers have demonstrated commercial SCR retrofit applications for mobile EGR-equipped heavy-duty diesel engines (where the original engine was equipped with or without catalysts) achieving NO_x reductions of 65%.[132] And, in addition, the California

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[129] MECA "Case Studies of the Use of Exhaust Emissions Controls on Locomotives and Large Marine Diesel Engines", October 2006. Available at http://www.meca.org/galleries/default-file/MECA%20locomotive%20and%20marine%20case%20study%20report%201006.pdf (Appendix III).

[130] Written Statement of the Manufacturers Emission Controls Association on the U.S. Environmental Protection Agency's Proposed Standards of Performance for Stationary Compression Ignition Internal Combustion Engines Docket ID Number OAR-2005-0029, September 8, 2005, p. 5 (Appendix III).

[131] *See* EPA Diesel Retrofit Technology Verification, Technical Summary, (available at: http://www.epa.gov/otaq/retrofit/tech-summary.htm) (Appendix III).

[132] *See*, e.g., EPA's Emerging Technology (Available at: http://www.epa.gov/otaq/diesel/prgemerglist.htm) (Appendix III).

Air Resource Board (CARB) has verified a specific non-road engine retrofit technology to reduce NO_x emissions by 80% with the use of SCR on certain non-road engine types.[133] In fact, several companies claim to have available retrofit SCR systems for a wide range of diesel engine types and applications. As an example, Haldor Topsoe markets a retrofit SCR system for "all types of diesel engine applications" that has been demonstrated in "off-road heavy machinery, on-road trucks, urban buses, trains, and marine applications."[134]

Recent research also supports the technical feasibility of SCR to smaller, portable compression ignition engines. Results of a recent test application of a urea SCR retrofit system to a 350 horsepower (hp) engine certified at 4 grams per brake horsepower hour (g/bhp-hr) NO_x achieved 41-67% NO_x reduction on a nonroad transient operating cycle.[135] Performance testing of an SCR diesel retrofit system for stationary and mobile engines that included a catalyzed diesel particulate filter (CDPF) and a diesel oxidation catalyst (DOC) for PM control resulted in 70% reduction of NO_x emissions based on a series of dynamometer tests on a Ford F550 dump truck.[136] An integrated catalytic control system for NOx and PM reduction in heavy-duty truck applications has demonstrated over 95% reduction in NO_x emissions with the SCR unit downstream if the engine and upstream of the PM controls.[137]

Additionally, EPA and Shell have not sufficiently explored other potential control options for the MLC compressor engines. For example, NO_x adsorbers have recently become available in the United States (2007).[138] According to MECA, "[t]he progress in developing and optimizing [NO_x adsorber] technology has been extremely impressive. Indeed, the Clean Diesel Independent Review Panel, charged by EPA to assess the technological progress in meeting the 2007/2010 standards, concluded in the latter part of 2002 that NO_x adsorber technology

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[133] Extengine Transport Systems, Advanced Diesel Emission Control System (ADEC) – Diesel oxidation catalyst (DOC) + Selective Catalytic Reduction (SCR), California Air Resources Board (CARB) Verified Nonroad Engine Retrofit Technologies (available at: http://www.epa.gov/otaq/retrofit/nonroad-list.htm) (Appendix III).

[134] Company website: http://www.topsoe.com/Business_areas/Automotive/Retrofit.aspx (Appendix III).

[135] Johnson, D R; Bedick, C R; Clark, N N; McKain, D L, "Design and testing of an independently controlled urea SCR retrofit system for the reduction of NOx emissions from marine diesels", Environmental Science & Technology, 2009-May; vol 43 (issue 10): pp 3959-63 (abstract available online at: http://pubs.acs.org/doi/abs/10.1021/es900269p) (Appendix III).

[136] Servati H B, Petreanu S,Marshall S E,Su H, Marshall R, Wu C-H, Hughes K, Simons L, Berrimann L, Zabsky J, Gomulka T, Rinaldi F, Tynan M, Salem J, Joyner J, "A NOx Reduction Solution for Retrofit Applications: A Simple Urea SCR Technology", SAE, Document Number: 2005-01-1857, April 2005 (abstract available at: http://www.sae.org/technical/papers/2005-01-1857) (Appendix III).

[137] Gekas I P, "NOx Reduction Potential of V-SCR Catalyst in SCR/DOC/DPF Configuration Targeting Euro VI Limits from High Engine NOx Levels", Society of Automotive Engineers (SAE), Document Number: 2009-01-0626, April 2009 (Abstract available online at http://www.sae.org/technical/papers/2009-01-0626) (Appendix III).

[138] *See* EPA's Diesel Retrofit Technology Verification (Technical Summary, at http://www.epa.gov/otaq/retrofit/tech-summary.htm) (Appendix III).

development was on track to help meet the on-road heavy-duty engine standards and no technological roadblocks were identified."[139] At least one manufacturer has introduced a diesel-powered passenger car in Europe and a diesel-powered light-duty truck in Japan with a combined NO_x adsorber/Diesel Particle Filter system, as of 2003.[140] The EM_x^{TM} ($SCONO_x$®) system, a NO_x adsorber system developed by Goal Line Technologies (now Emerachem), is marketed for, among other things, mobile heavy-duty diesel applications with NO_x reductions greater than 90%.[141]

Neither the PSD permit application nor EPA's proposed permit provide sufficient discussion or analysis of whether the proposed BACT emission limit reflects the maximum degree of reduction of NO_x emissions that can be achieved from the MLC compressor engines. Instead, Shell has proposed an emission limit equal to the Tier 3 engine standards and equal to the New Source Performance Standards (NSPS) for stationary compression ignition internal combustion engines, and claims that this limit reflects BACT but does not thoroughly consider the use of add-on controls to reduce this limit even further. While this Tier 3 emission limit represents the most stringent of the new emissions standards for non-road diesel engines,[142] it does not necessarily reflect the maximum degree of reduction in NO_x emissions that can be achieved as required by the definition of BACT at 40 CFR § 52.21(b)(12).

The fact that the MLC compressor engines meet NSPS for stationary compression ignition internal combustion engines does not mean that this level of control constitutes the best available control for these units. EPA has made clear in its policy guidance for BACT determinations that, since an NSPS must always be met, it constitutes a legal "floor" for the BACT, which cannot be less stringent.[143] According to EPA, NSPS represents what *every* source can achieve, not the best an individual source can achieve. In fact, EPA states, "in only a few BACT cases should you encounter the same criteria that limited the stringency of the NSPS" indicating that BACT, except in rare occasions, is going to be more stringent than the NSPS.[144] The Clean Air Act defines BACT as "based on the maximum degree of reduction . . . on a case-by-case basis."[145] EPA policy states "BACT represents the best level of control the source can provide and should

[139] Written Statement of the Manufacturers Emission Controls Association on the U.S. Environmental Protection Agency's Proposed Standards of Performance for Stationary Compression Ignition Internal Combustion Engines Docket ID Number OAR-2005-0029, September 8, 2005, p. 6 (Appendix III).
[140] *Id.*
[141] http://www.emerachem.com/application/heavy_duty/ (Appendix III).
[142] NSPS IIII, 40 C.F.R. part 60, Subpart IIII applies to the MLC compressor engines.
[143] *In re: Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824 (June 21, 1989) ("the applicable NSPS limitation merely serves as a floor for the BACT limitation, i.e., the BACT limitation must never fall below the level of stringency set by the NSPS."); *see also* 42 U.S.C. § 7479(3).
[144] Letter from Gary McCutchen, EPA to Richard Grusnick, Alabama Department of Environmental Management (July 28, 1987) (Appendix III).
[145] CAA section 169(3), 42 U.S.C. § 7479.

not be based on a category-wide minimal standard like an applicable NSPS."[146]

In addition to the NSPS for stationary compression ignition internal combustion engines, individual states as well as the Northeast Ozone Transport Commission (OTC) and Regulatory Assistance Project (RAP) have developed standards for stationary engines that apply to broad populations of new and in-use engines. These limits are more stringent than the NSPS and EPA must consider these emission rates as minimum requirements, as well, for the Shell engines. The OTC model rule applies to new and in-use non-emergency natural gas and diesel fueled engines greater than 200 hp with a diesel NO_x standard of 6.8 pounds per megawatt hour (lb/MWh), or 3 grams per kilowatt hour (g/kWh).[147] The RAP model rule applies to new engines greater than 200 hp with a NO_x standard of 1.5 lb/MWh, or 0.7 g/kWh, for engines manufactured after January 1, 2008. [148] In addition, the state of Texas requires new stationary diesel engines (after 2005) located in attainment areas to meet a NO_x standard of 3.11 lb/MWh, or 1.4 g/kWh.[149] EPA's Tier 4 nonroad diesel engine standards will be implemented for engines in the 175-750 hp size range beginning in 2011. Nonroad engines of this size must meet a NO_x emission standard of 0.3 g/bph-hr, or 0.4 g/kWh.[150] All of these limits demonstrate achievable levels of control for these and similar types of engines and, therefore, must be considered in EPA's BACT analysis.

Thus, for all of the above reasons, EPA has not adequately evaluated BACT for NO_x for the MLC compressor engines. EPA has not demonstrated that the proposed emission limit reflects the maximum degree of NO_x reduction that can be achieved and has failed to evaluate all technically feasible control options. Consequently, EPA must determine through a true and thorough top-down analysis the level of control that reflects the maximum degree of NO_x reduction that can be achieved from the MLC compressor engines and impose a NO_x emission limit that reflects that maximum degree of NO_x control.

2. Critique of the NO_x BACT analysis for smaller compression ignition internal combustion engines.

EPA is proposing that BACT for the smaller compression ignition engines on the Discoverer is "good combustion practices."[151] This is the same limit as proposed by Shell in its application.[152] This BACT determination applies to the two hydraulic power unit (HPU) engines, two cranes, three cementing units and two logging winches, which collectively represent over 50 percent of

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[146] Letter from Gary McCutchen, EPA to Richard Grusnick, Alabama Department of Environmental Management (July 28, 1987).
[147] Stationary Diesel Engines in the Northeast: An Initial Assessment of the Regional Population, Control Technology Options and Air Quality Policy Issues, NESCAUM (June 2003) (Appendix III).
[148] *Id.*
[149] http://files.harc.edu/Sites/GulfCoastCHP/Regulations/TexasPermitElectricGeneratingUnits.pdf (Appendix III).
[150] http://www.epa.gov/nonroad-diesel/2004fr/420f04032.htm#standards (Appendix III).
[151] *See* EPA Stmt of Basis at 50; EPA draft OCS PSD Permit for Shell Chukchi Sea Operations, at Conditions G.3, H.3 and I.3.
[152] *See* Shell Revised OCS App. at 37.

annual NO_x emissions (and over 75% of hourly NO_x emissions) from the Discoverer.

EPA eliminated all other control options, except the use of injection timing retard (ITR) and intake air cooling (AC), as technically infeasible. According to the discussion in EPA's draft permit, use of ITR and AC technology will adversely impact the performance of the catalytic diesel particulate filter (CDPF) needed for PM control. As with the MLC compressor engines, EPA dismissed the use of selective catalytic reduction (SCR) as an add-on control for these smaller engines due to a need for portability for these engines and due to space limitations. Part of EPA's justification for not including SCR in its BACT analysis is because "there are no determinations for installing SCR on diesel engines under 500 hp in the EPA RBLC or CA-BACT."[153] It is not sufficient to simply compare the proposed BACT determination to the BACT determinations of other permitted sources, especially here where Shell is proposing non-traditional operations that are not readily compared to traditional sources.

The NO_x BACT analysis should also be based on a review of the maximum degree of emission reductions that can be achieved for the engines. Again, we do not agree that the size, portability and space limitations necessarily preclude the use of SCR, or other technologies, such as NO_x adsorbers, for these engines. EPA must more thoroughly investigate these options in determining the BACT limits for these engines.

As previously discussed for the MLC compressor engines, commercially demonstrated applications of SCR technology to non-road engines supports the use of this technology for smaller, portable applications and, therefore, EPA must consider it as a technically feasible option in the BACT analysis for the smaller compression ignition internal combustion engines on the Discoverer. In addition to the examples provided for the MLC compressor engines, EPA's Diesel Retrofit Technology Verification program lists several examples of SCR retrofit technologies applicable to smaller mobile engine applications. Johnson Matthey and Nett Technologies, Inc. offer multiple SCR technologies covering a wide range of engine sizes (as small as 250 hp), a wide range of ages and applicable to both EGR and non-EGR engine technologies.[154] And again, the published test results from the application of a urea SCR retrofit system to a 350 hp engine certified at 4 g/bhp-hr NO_x showing 41-67% NO_x reduction during a non-road transient operating cycle demonstrates the technical feasibility of SCR retrofit technology to smaller engines.[155]

The various engines covered by this general BACT determination have permitted emission rates, which are defined as BACT limits, as follows:

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[153] *See* EPA Stmt of Basis at 49.

[154] *See, e.g.*, EPA's Emerging Technology List (available at: http://www.epa.gov/otaq/diesel/prgemerglist.htm) (Appendix III).

[155] Johnson, D R; Bedick, C R; Clark, N N; McKain, D L, "Design and testing of an independently controlled urea SCR retrofit system for the reduction of NOx emissions from marine diesels", Environmental Science & Technology, 2009-May; vol 43 (issue 10): pp 3959-63 (Appendix III).

Unit	NO_x BACT Limit in g/kWh	Permit Condition
HPU Engine FD-12	13.155	G.2.2.1
HPU Engine FD-13	13.155	G.2.2.1
Deck Crane FD-14	10.327	H.2.2.1
Deck Crane DF-15	10.327	H.2.2.1
Cementing Unit FD-16	13.155	I.2.2.1
Cementing Unit FD-17	13.155	I.2.2.1
Cementing Unit FD-18	15.717	I.2.2.1
Logging Winch FD-19	15.717	I.2.2.1
Logging Winch FD-20	7.5	I.2.2.1

According to EPA and Shell, the hydraulic power units (HPU) will be used "very similarly" to the MLC compressor engines.[156] The HPU engines are 250 hp Detroit Diesel 8V-71 engines and the BACT limit is based on engine dynamometer test data reported in EPA's 2002 Diesel Health Assessment. The cementing unit engines (FD-16, FD-17, FD-18) and logging winch engine FD-19 are also Detroit Diesel 8V-71 engines (or from the same "family" of engines) with BACT limits also based on EPA's 2002 Diesel Health Assessment data.

The BACT limits for the FD-20 logging winch and the two deck cranes are based on manufacturer emission data and likely represent good combustion practices. These BACT limits are lower than for the other engines. EPA's proposed BACT limits for the Detroit Diesel 8V-71 engines may not reflect the "good combustion practices" that it determined were the best available controls. At a very minimum, EPA should quantify the reductions in NO_x emissions that can be expected from implementation of the good combustion practices defined as BACT instead of requiring the practices but enforcing an emission limit that is simply based on average engine operation for these 8V-71 engines. We support EPA's requirement to test theses engines (Conditions G.7, H.7 and I.7) to verify emission limits can be achieved; however, these data are needed prior to issuing a permit to set a BACT limit and determine BACT. In the event that the test data for these units demonstrate the ability to meet lower NO_x limits, EPA must revise the BACT limits accordingly.

EPA did not consider certain retrofit technologies that are available for some of these engines to greatly reduce NO_x and other pollutant emissions. For example, Clean Cam Technology Systems makes a Cam Shaft Cylinder Reengineering Kit for Detroit Diesel 8V71 engines. These retrofits are commercially available and have been installed on hundreds of stationary and portable units.[157] The manufacturer claims NO_x emissions with the retrofit technology will be no more than 4.5 g/bhp-hr, which would correspond to a limit of 6 g/kWh, or less than half of the proposed BACT limit for these engines.[158] EPA must consider these and any other available retrofit technologies that will reduce NO_x emissions from these engines in its BACT analysis.

[156] *See* EPA Stmt of Basis at 28.
[157] CARB Diesel Risk Reduction Plan, Diesel PM Control Technologies, Appendix IX, October 200, p. IX-59 (available at: http://www.arb.ca.gov/diesel/documents/rrpapp9.pdf) (Appendix III).
[158] Note, 1 bhp-hr = 1.341 kWh so 4.5 g/bhp-hr * (1.341 bhp-hr/ 1 kWh) = 6 g/kWh

This type of technology could be applicable to the HPU engines as well as the cementing units and logging winches.

The previously mentioned OTC model rule that applies to in-use non-emergency diesel fueled engines greater than 200 hp must also be considered in EPA's BACT review for these engines. The OTC NO_x emission limit for existing diesel engines is 3 g/kWh, which would represent up to an 80% reduction in emissions from these engines.[159]

Thus, for these reasons, EPA has not adequately evaluated BACT for NO_x for the small compression ignition engines. We request that EPA complete a much more rigorous review of BACT for these engines, as required by 40 C.F.R. § 52.21(b)(12). EPA has failed to show that the proposed emission limits reflect the maximum degree of NO_x reduction that can be achieved from these engines (in fact, they appear to only reflect average operation of these engines) and has failed to evaluate all technically feasible control options. Consequently, EPA must determine through a true and thorough top-down analysis the level of control that reflects the maximum degree of NO_x reduction that can be achieved from the small engines and impose a NO_x emission limit that reflects that maximum degree of NO_x control.

3. Critique of the PM BACT analysis for diesel generator engines.

EPA is proposing the use of oxidation catalysts (OxyCat) as BACT for the six generator diesel internal combustion engines.[160] This is the same limit as proposed by Shell in its application.[161] EPA eliminated the use of catalytic diesel particulate filters (CDPF) as technically infeasible control options for these engines. According to EPA, "[s]ince CDPF systems are not commercially available in combination with SCR systems for diesel engines such as the Discoverer's generator diesel IC engines, EPA believes CDPF systems are technically infeasible for this specific application."[162] Further, EPA assumes that even if CDPF technology were technically feasible, it would not be a cost-effective control option.[163]

Regarding EPA's reference to cost-effectiveness for CDPF control for the six generator engines, EPA must provide a comparative assessment of the economic impacts of applying this technology in similar applications. Shell provided a cost estimate for the use of CDPF control for the six generator engines of roughly $22,000 per year per ton of PM removed for all six engines.[164] In its application, Shell simply states "[t]his is not cost effective."[165] If EPA is going to eliminate the use of CDPF technology as an effective control option based on cost-effectiveness then it must present a detailed argument as to why $22,000 per ton of PM removed

[159] The highest BACT limit for these engines is for the cementing units at 15.717 g/kWh. (15.717 – 3) g/kWh / 15.717 g/kWh = 80.1% reduction.
[160] *See* EPA Stmt of Basis at 57; EPA draft OCS PSD Permit for Shell Chukchi Operations at Condition C.2.
[161] *See* Shell Revised OCS App. at 47.
[162] EPA Stmt of Basis at 56.
[163] *See* EPA Stmt of Basis at 56, fn8.
[164] *See* Shell Revised OCS App. at Appendix C.
[165] *See* Shell Revised OCS App. at 47.

per year is not considered cost effective for these units. This argument must include an analysis of employing these technologies for Shell's proposed operations in the Beaufort Sea as well. EPA must compare the associated per ton costs with similar applications of CDPF.

According to EPA guidance, the applicant must demonstrate that costs of pollutant removal are "disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations."[166] EPA and Shell have provided no such comparison analysis to support its claim that $22,000 is not cost effective. In fact, it does not appear that $22,000 per ton of PM removal per year is necessarily cost prohibitive. EPA estimates that the cost of several diesel retrofit programs: (1) the Urban Bus Retrofit and Rebuild program ($31,500/ton of PM reduced); (2) the 2007 Heavy-Duty diesel emission standards ($14,200/ton); and (3) the Non-road Tier 4 emission standards ($11,200/ton) indicate that "retrofits can be a cost effective way to reduce air pollution."[167]

Regarding EPA's determination that CDPF technology is technically infeasible, it is not sufficient to simply provide one manufacturer's statement that it is unaware of CDPF applications for these engine types. In addition to comparing the proposed BACT determination to the BACT determinations of other permitted sources, the BACT analysis should also be based on a review of the maximum degree of emission reductions that can be achieved for the engines based on a rigorous investigation of all available control options. EPA and Shell must more thoroughly investigate the use of CDPF in application where SCR is also used to control NO_x in determining the BACT limits for these engines.

Several manufacturers have demonstrated commercial CDPF retrofit applications in conjunction with SCR to control NO_x emissions demonstrating that many of the technical considerations that Shell raises (e.g., backpressure on the engines, cross-sectional area for the catalyst matrix, filter element exchange frequency, etc.) can be overcome. These applications were for a wide range of engine sizes and a wide range of ages.[168] And, as previously mentioned in the context of SCR applicability, there is recent research to support the effectiveness of integrated catalytic control systems for NO_x and PM reduction in both stationary and mobile applications for small and large engines.[169] However, even if these particular technologies are not directly applicable to the older

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[166] Draft NSR Workshop Manual, at B.32 (October 1990).

[167] EPA 420-S-06-002, Diesel Retrofit Technology: An Analysis of the Cost-Effectiveness of Reducing Particulate Matter Emissions from Heavy-Duty Diesel Engines Through Retrofits, March 2006, p. ii (Appendix III).

[168] *See, e.g.*, EPA's Emerging Technology list available at: http://www.epa.gov/otaq/diesel/prgemerglist.htm (Appendix III).

[169] Gekas I P, "NOx Reduction Potential of V-SCR Catalyst in SCR /DOC/DPF Configuration Targeting Euro VI Limits from High Engine NOx Levels", Society of Automotive Engineers (SAE), Document Number: 2009-01-0626, April 2009 (Abstract available online at http://www.sae.org/technical/papers/2009-01-0626) (Appendix III); Servati H B, Petreanu S,Marshall S E,Su H, Marshall R, Wu C-H, Hughes K, Simons L, Berrimann L, Zabsky J, Gomulka T, Rinaldi F, Tynan M, Salem J, Joyner J, "A NOx Reduction Solution for Retrofit Applications: A Simple Urea SCR Technology", SAE, Document Number: 2005-01-1857, April 2005 (Abstract available online at http://www.sae.org/technical/papers/2005-01-1857)

generator engines proposed for use by Shell, it is still possible that the use of CDPFs is potentially feasible for these engines. Nothing in the permitting materials indicates with certainty that this particular technology is technically infeasible. Without such firm evidence EPA must insist that Shell perform the needed investigations to make a more solid determination.

4. Critique of the PM BACT analysis for the incinerator.

EPA is proposing "Good Combustion Practices" as BACT for the incinerator.[170] This is the same BACT as proposed by Shell in its application.[171] EPA eliminated the use of add-on controls for the incinerator as technically infeasible. The Discoverer incinerator (TeamTec GS500C) is a small waste incinerator rated at 276 lb/hr, with a daily rating of 6624 lbs/day. Shell plans to incinerate domestic and other non-hazardous solid waste (trash) and liquid sewage sludge.[172] Shell describes this incinerator as a two-stage, batch-charged unit. The TeamTec GS500C unit is a small unit (approximately 8'x 6'x 7' in dimension) with an option for simultaneous combustion of sewage sludge and solid waste.[173]

Shell requested Owner Requested Restriction (ORR) limits for PM_{10} (8.2 lbs/ton) and $PM_{2.5}$ (7 lb/ton), which is a small fraction of the total AP-42, Table 2.2-1 PM_{total} emission factor for an uncontrolled multiple hearth sewage sludge incinerator (100 lb/ton). It is not clear how fine particulate matter will be controlled to this level without the use of additional controls.

Shell has also requested an ORR of 1,525 lb/day (23% incinerator capacity) in addition to the ORR limits for PM_{10} and $PM_{2.5}$.[174] Even at these ORRs the incinerator $PM_{2.5}$ emissions account for 32% of the 24-hour $PM_{2.5}$ emissions and contribute to over 50% of the 24-hour $PM_{2.5}$ (and PM_{10}) concentrations at maximum impact locations.[175]

Both Shell and EPA conclude that no additional control is BACT, but do not explain how these ORR emission factors will be achieved absent addition control. Vendor data and source test data is absent to confirm these ORRs can be achieved. We support the EPA's requirement to test the incinerator (FD-23) to verify whether emission limits can be achieved (Condition K.7); however, these data are needed prior to issuing a permit to set a BACT limit and determine BACT.

The permit does not include an alternative procedure if the test fails to achieve the ORRs. One option would be to further reduce the incinerator throughput, but it is not clear whether further reduction below a 23% operating capacity can support the vessel's waste generation. Another

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(Appendix III).
[170] EPA Stmt of Basis at 61; EPA draft OCS PSD Permit Shell for Chukchi Operations at Condition K.2.
[171] Shell Revised OCS App. at 48.
[172] Shell Revised OCS App. at 4.
[173] TeamTec Marine Product Brochure (Appendix III).
[174] Shell requested an even lower limit on the incinerator in its September 17, 2009 comments. This even lower limit of 1,300 lb/day represents less than 20% incinerator capacity.
[175] Shell Revised OCS App. at Table 7-4 (2/23/09).

option would be to develop alternative waste handling strategies to reduce waste capacity including collection and backhaul, if needed, rather than on-site incineration. These alternative requirements should be clearly specified in the permit.

We request that EPA require Shell test this incinerator to verify what emission rate can be achieved, or provide vendor data to verify that the PM_{10} (8.2 lbs/ton) and $PM_{2.5}$ (7 lb/ton) ORRs can be met without any additional emission control. Additional control may be required to achieve these emission levels. Or alternative waste handling strategies may need to be adopted.

In the event that the test data for the unit demonstrate the ability to meet lower PM_{10} and $PM_{2.5}$ limits, EPA must revise the BACT limits accordingly. In fact, Shell's own findings in the RACT/BACT/LAER clearinghouse demonstrate that lower limits can be achieved on similar-sized units using "Proper Operation and Maintenance" practices. Specifically, similar waste combusting units permitted at the Kenai Refinery in Alaska with 350 lb/hr maximum throughput ratings have a BACT limit for PM_{10} of 0.2 lb/hr, or 1.1 lb/ton.[176,177] EPA must consider and evaluate this limit as an applicable BACT limit for the incinerator on the Discoverer. EPA should require a standard operating procedure/waste separation plan to instruct employees on how to segregate waste to ensure that hazardous/toxic material is not inadvertently incinerated.

4. Critique of the incinerator SO_2 emissions.

Shell references AP-42, Table 2.1-12 as its source for a SO_2 emission factor yet it is not clear why Shell uses this "D" rated emission factor for a refuse combustor of 2.5 lbs/ton rather than the "B" rated emission factor of 28 lb/ton found in Table 2.2-1 for a multiple hearth sewage sludge incinerator (which is 11 times larger). If Shell has reduced this emission factor based on fuel type, this must be explained.

5. Critique of the incinerator sewage combustion.

We request that EPA clarify the amount and type of sewage that will be incinerated in Discoverer incinerator versus treated by the Marine Sanitation Device (MSD) and discharged overboard as described in Shell's NPDES NOI. In our comments on the NPDES permit, we have requested additional information on the type and treatment levels achieved by the Marine Sanitation Device (MSD).

6. Critique of the PM BACT analysis for boilers.

EPA is proposing "Good Combustion Practices" as BACT for the two boilers onboard the Discoverer.[178] This is the same BACT as proposed by Shell in its application.[179] EPA eliminated the use of add-on controls for the boilers as technically infeasible.

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[176] RBLC, AK-0053, 3/21/2000

[177] 0.2 lb_{PM10}/hr / 350 lb_{waste}/hr * 2000 lb/ton = 1.1 lb_{PM10}/ton_{waste}

[178] EPA Stmt of Basis at 60; EPA draft OCS PSD Permit for Shell Chukchi Operations at Condition J.2.

[179] Shell Revised OCS App. at 48.

As with the incinerator, we support EPA's requirement to test the boilers (FD-21 and FD-22) to verify that BACT emission limits can be achieved (Condition J.5); however, these data are needed prior to issuing a permit to set a BACT limit and determine BACT. We request that EPA require Shell test both units to verify what emission rate can be achieved, or provide vendor data to verify that the PM_{10} (0.0235 lb/mmBTU) and $PM_{2.5}$ (0.0235 lb/mmBTU) limits can be met without any additional emission control.

In the event that the test data for the units demonstrate the ability to meet lower PM_{10} and $PM_{2.5}$ limits, EPA must revise the BACT limits accordingly. EPA must also explain why the proposed BACT limits exceed AP-42 emission factors for this source. Table 1.3-1 in Section 1.3 of EPA's AP-42 compilation of emission factors lists "A" rated emission factors for NO_x and PM_{10} of 20 pounds per thousand gallons (lb/10^3gal) and 2 lb/10^3gal, respectively.[180] AP-42 emission factors represent an average of a range of emission rates. Therefore, units applying BACT would presumably be able to achieve much lower emission rates than what is presented as the average factor in AP-42. The proposed BACT limits for the two boilers, in comparison, are equivalent to 26.6 lb/10^3gal of NO_x and 3.1 lb/10^3gal of PM.[181] EPA must explain why the boilers on the Discoverer will not have BACT limits at least as stringent as the average emission rates established in AP-42.

7. Critique of the VOC BACT analysis for vented sources.

EPA's Statement of Basis at Section 4.1 concludes that "…BACT must be determined for *each emission unit on the Discoverer* which emits NOx, PM, $PM_{2.5}$, PM_{10}, SO_2, *VOC* and CO while the drillship is operating as an OCS source." [emphasis added]. EPA's Statement of Basis at Section 4.5 examines VOC BACT for combustion sources, but does not examine vented sources of VOC (e.g. mud degassing).

Mud degassing emissions can substantially contribute to VOC and greenhouse gas (GHG) emissions. Mud degassing systems are used to remove entrained formation gas from the mud to maintain higher mud density for well control. Drilling mud degassing units extract entrained gas from the mud at the surface and vent this gas directly into the atmosphere.

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[180] AP-42 emission factors are given a rating of "A" through "E" with "A" indicating a high level of confidence in the factor ("A" = Excellent. Factor is developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability. Tests are performed by a sound methodology and are reported in enough detail for adequate validation).

[181] Permit Conditions J.1.1 and J.1.3 list a NOx BACT limit of 0.2 lb/mmBTU and a PM_{10} BACT limit of 0.0235 lb/mmBTU, respectively. Based on the diesel fuel heating value in Shell's engineering calculations (Appendix B of Shell's Application on 2/23/09) of 0.1331 mmBTU/gal:

0.2 lb/mmBTU * 0.1331 mmBTU/gal * 1000 gal/10^3gal = 26.6 lb/10^3gal NO_x
0.0235 lb/mmBTU * 0.1331 mmBTU/gal * 1000 gal/10^3gal = 3.1 lb/10^3gal PM_{10}

Recognizing that mud degassing is a significant emission source, in 2007, MMS hired a consulting firm to develop offshore drilling mud degassing emission factors, among other emission factors, to improve offshore oil and gas emission estimates.[182] MMS's drilling mud degassing emission factors have been reviewed and accepted by both API[183] and The Climate Registry.[184] The standard total hydrocarbon (THC) emission factor for water-based mud from an offshore drilling mud system is 881.84 lb THC/drilling day. The standard methane (CH_4) emission factor from an offshore drilling mud system is 0.2605 tonnes of CH_4 per drilling day.

We request that EPA require Shell to revise its mud degassing emission computations using standard emission factors developed by MMS. Shell's computations use a non-standard approach. Shell estimates *only 136 lbs* of VOC are vented during the entire *drilling season.*[185] Shell's emission estimate severely underestimates the GHG emission impact[186] and VOC emission contribution.

Additionally, VOC BACT must be examined for vented gas from the mud tanks and degassing units. Flares or other hydrocarbon vapor control devices should be considered and the associated PM emissions from these devices should be accounted for in the permit analysis. The we also request that EPA require Shell to calculate HAP emissions based on the substantially higher, revised VOC emission estimate.

E. A Proper BACT Analysis Must Include the Ancillary Vessels.

In its permit application Shell states that

> One interpretation of applicable regulations is that the anchor handler vessels and resupply ship are part of the *Discoverer* "stationary source" when they are (however briefly) connected to the *Discoverer*. As part of the stationary source, one might conclude that BACT must be applied to the emission units on these vessels. ***Shell has not conducted a detailed BACT analysis for these vessels***

[182] Wilson, Darcy, Richard Billings, Regi Oommen, and Roger Chang, Eastern Research Group, Inc. *Year 2005 Gulfwide Emission Inventory Study*, U.S. Department of the Interior, Minerals Management Services, Gulf of Mexico OCS Region, New Orleans, December 2007, Section 5.2.10 (available at: http://www.gomr.mms.gov/PI/PDFImages/ESPIS/4/4276.pdf) (Appendix III).
[183] American Petroleum Institute (API), Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry, August 2009 (Available at: http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf).
[184] The Climate Registry Oil and Gas Production Protocol, Draft for Public Comment, May 2009 (available at: http://www.theclimateregistry.org/downloads/2009/05/Oil-and-Gas-Production-Protocol.pdf).
[185] EPA Stmt of Basis, at Section 3.4.12, Drilling Mud System (FD-32).
[186] NOTE: Methane is of particular concern as a greenhouse gas since it is over 20 times more effective at trapping heat in the atmosphere than carbon dioxide over the same 100-year period.

because there is no way implementation of emission controls beyond good operating practices could be cost effective.[187]

In order to reach the conclusion that good operating practices are the best available for controlling emissions from these vessels, a BACT analysis is required. We ask that Shell and EPA utilize the top-down approach for applying BACT to the ancillary vessels.

In doing so, the fact that equipment (including vessels) are leased by Shell cannot serve as adequate grounds for concluding that applying emissions controls would be economically infeasible. Both the CAA and EPA's regulations apply to "owners *or operators*,"[188] as well as "any equipment, activity, or facility."[189] Thus, it is not enough that the equipment is not owned by Shell since Shell is the operator. At the very least, Shell and EPA must disclose the costs to Shell of owning such equipment versus the costs of leasing it, what the savings are, and in light of all those figures whether it is economical to apply control technologies.

IV. Specific Comments on Permit Conditions, Compliance Demonstration, Monitoring and Reporting Measures.

A. Source Testing.

We support EPA's requirements to verify that emission limits can be met by stack testing each emission unit.[190] Stack test data are critical to verify if permit limits can be met. The new stack testing requirements are a substantial improvement over the 2007 permit and we applaud EPA's more stringent emission verification approach.

The proposed permit requires stack testing to be completed prior to each drilling season, but does not specify how far in advance the testing must be done, nor does the permit include a remedy for failed tests. Permit condition B.7.8 requires all stack test results to be provided to EPA within 45 days of testing. However, if stack testing only occurs a few days prior to the drilling season, there will not be adequate time to analyze and remedy any test results that exceed the permit limits before drilling starts. With a 168 operating day limit per drilling season, a quarter of the drilling season could pass before EPA even receives the test results.

We request that EPA require all stack tests to be completed at least 180 days prior to each drilling season to ensure there is adequate time to analyze and remedy any test results that exceed permit limits. The permit must clearly state that any emission unit that fails to meet the permitted emission limit must not be operated until the unit is repaired or additional emission control is installed. Collecting test data, and merely reporting excess emissions if tests fail to

[187] Shell Revised OCS App. at 29 (emphasis added).
[188] 42 U.S.C. § 7475 (emphasis added); 40 C.F.R. §§ 52.21(n), (o).
[189] 42 U.S.C. § 7627(4)(C); 40 C.F.R. § 55.2.
[190] *See* Conditions: C.6 (Generator Engines), F.5 (MLC Compressor Engines), G.7 (HPU Engines), H.7 (Deck Cranes), I.7 (Cement Unit and Logging Winch), J.5 (Boilers), K.7 (Incinerator), L.4 (Supply Ship), N.9 (Icebreaker #1), O.11 (Icebreaker #2), and Q.6 (Oil Spill Response Fleet).

meet permit limits, is not an acceptable solution, especially in the cases where the annual NO_x and 24-hour $PM_{2.5}$ NAAQS compliance margins are very tight. A failed test, unresolved, could result in a NAAQS exceedance.

EPA's proposed permit included several conditions where one unit is tested to represent the emission performance of other like units (e.g. Condition C.6 that requires two of the Discoverer generator engines to be tested in the first year to represent the emissions of all six engines). In these cases, the permit must clearly state that if the representative unit fails the stack test, all like emission units correspondingly are assumed to have failed. All like units must be repaired or additional emission controls must be installed to meet the limit. Alternatively, additional stack tests on the remaining units could be performed to verify individual unit compliance to isolate the problem unit(s).

We request that EPA provide more information in its Statement of Basis to demonstrate how it confirmed stack testing of one unit will be representative of another similar unit. Information on the unit year, model type and historical use should be provided to demonstrate that the equipment is of like equipment specification and has a similar operating history. EPA must demonstrate that the units are representative, or it must require each unit to be tested individually before the first drilling season.

EPA does not require source tests for the Discoverer's main propulsion engines. We question whether the main propulsion engines would actually be completely shutdown when the Discoverer is operating as an OCS source.[191] If, under further examination, EPA determines the propulsion units will be operated, source testing should be required.

Shell's September 17, 2009 comments to EPA on the proposed permit at p.9, request that EPA remove the stack test requirements for the: MLC Compressor Engines, HPU Engines, Cranes, Cementing and Logging Units, the Boilers and Utility Generators. Shell proposes that EPA rely on generic, average emission factors for these units, without any stack testing. We do *not* support Shell's request to eliminate these critical stack testing requirements and urges EPA to keep all testing requirements, as proposed.

1. Load factors, testing and monitoring.

Shell's application includes a number of assumed operating loads. Emissions are a function of load. EPA's proposed permit accepts these assumed loads and requires stack testing within the expected operating range (see, e.g., Conditions C.6.2, F.5.2, G.7.2, etc.). The permit, however, fails to sufficiently ensure that calculated emission rates used for compliance demonstration are based on the maximum emissions scenario for the range of loads tested. We request EPA revise the following permit conditions to be more explicit regarding this point. We request permit conditions C.6.5, F.5.5, G.7.5, H.7.5, I.7.5, J.5.5, K.7.5, N.9.8, N.9.9, N.9.10, O.11.8, O.11.9, O.11.10, Q.6.5 read:

*For each engine, **each load factor** and each pollutant, the permittee shall determine*

[191] *See, supra* at 12-15.

emission factors in the following units: g/kW-hr, g/kWe-hr, lbs/kW-hr, lbs/kWe-hr and lbs/gallon.

Conditions C.7.8, F.6.5, G.8.7, H.8.7, I.8.7, J.6.5, K.8.5, N.10.9, O.12.9, Q.7.8 then require the use of the highest emission factor calculated in the corresponding sections (revised above) and will ensure all loads are considered when making this calculation of highest emissions.

We request that EPA include a recordkeeping requirement to track the operating loads during the first drilling season to verify actual operating load ranges. The permit should also include requirements for additional stack testing if actual operating practices include operating loads outside the currently assumed ranges.

2. Fuel monitoring.

Shell's September 17, 2009 comments to EPA on the proposed permit at p.6, requests EPA remove the requirements for continuous individual fuel metering on most of the equipment as required by permit conditions: [F.6 (MLC Compressor Engines), G.8 (HPU Engines), H.8 (Deck Cranes), I.8 (Cement Unit and Logging Winch), J.6 (Boilers), N.10 (Icebreaker #1), O.12 (Icebreaker #2), and Q.7 (Oil Spill Response Fleet)].

Shell's September 17, 2009 comments to EPA on the proposed permit at p.6, requests EPA to allow load monitoring to replace fuel monitoring on its support icebreakers and the Nanuq. Shell states load monitoring systems are already installed on these vessels, and it can provide information to verify the load monitoring is more accurate. We request that EPA obtain additional information to verify the type of automated load tracking systems Shell is proposing and to determine if they are more accurate than fuel monitoring. Shell should provide information on the specific load tracking systems proposed for each unit. This additional information should be provided for public review. While Shell has installed load monitoring capability on the currently contracted vessels, it has requested flexibility in support vessel selection for future operating years, and, must explain how it will provide equivalent capability on future contract vessels.

Shell's September 17, 2009 comments to EPA do not provide an adequate alternative proposal to replace EPA's proposed continuous individual fuel metering requirements on the M/V Discoverer equipment. More information is needed from Shell to better understand how an equal level of compliance and accuracy can be achieved without individual fuel meters.

The proposed permit requires that fuel flow meters measure the fuel flow rate with an accuracy equal to or better (less) than two percent of the meter's upper range value (see, e.g., Condition C.7.1.3). Since compliance with the NAAQS, as demonstrated in the ambient air quality analysis for the proposed permit, can just barely be demonstrated for $PM_{2.5}$ on a short-term basis, it is imperative that the accuracies of the measurements that are the basis for the modeling inputs be no more than the margin needed to demonstrate compliance with the NAAQS. That is to say, since the difference between the 24-hour $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$ and the maximum predicted 24-hour average $PM_{2.5}$ concentration plus the background concentration used in the ambient analysis is less than 4%, the fuel flow meters must be accurate, at least, to this level (i.e.,

$\leq 4\%$).

Since the emissions inputs for the model are based, in general, on multiplying the applicable emission factor by the associated operating factor (e.g., fuel usage rate) then the accuracy of this input is determined by the sum, in quadrature, of the fractional uncertainties associated with each factor.[192] If, as is indicated in Shell's September 17, 2009 comments (p. 11), the uncertainty in the stack test data is upwards of 15%, then Shell must be able to demonstrate compliance with the NAAQS considering a margin of error no less than 15%.[193] This would mean the predicted 24-hour $PM_{2.5}$ concentration would need to be less than 30.4 $\mu g/m^3$ when considering the applicable background concentration. In fact, the highest predicted 24-hour $PM_{2.5}$ concentration from the permit modeling was 33.7 $\mu g/m^3$ with a background concentration of 8 $\mu g/m^3$.[194] Therefore, EPA must establish permit limits that, when considering the accuracy of the emission factor and operating data, demonstrate compliance with the NAAQS with a margin of error no less than the accuracy of the input data.[195] The proposed permit, when considering the accuracy data supplied by Shell, does not demonstrate compliance with the short-term $PM_{2.5}$ NAAQS.

3. Relief well emissions.

Shell's application requests approval to drill up to 5 wells in a 168 day time period. Shell's application states that Table 2-1 includes relief well emissions within the 168 day total drilling period.[196]

> ***With respect to relief well emissions***, in addition to the fact that any such drilling is an extremely remote contingency, ***Table 2-1 already includes the relevant emissions information***. The only emissions that would be associated with well control events would be emissions produced from drilling the relief well in the very unlikely event that this were necessary to control a blowout. No emissions would be associated with emergency deployment of the ship's Subsea Blowout Preventer (SSBOP).[197]

EPA's proposed permit condition B2.3 requires Shell to include any time spent drilling a relief well from the total 168 day operating period. We agree that the time needed to drill a relief well should be deducted from the total 168 day operating period. We also agree that relief well drilling emissions must be included in PTE calculation.

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[192] The quadrature sum is the square root of the sum of the squares.

[193] The uncertainty in the calculated emission rate would be the square root of the sum of the squares of the fractional uncertainties, as follows:

$$q = ((2\%)^2 + (15\%)^2)^{1/2} = 15.1\%$$

[194] EPA Stmt of Basis at Table 12a, Appendix B, Figures and Tables.

[195] As determined by the sum, in quadrature, of the fractional uncertainties for each variable.

[196] Shell Revised OCS App. at 22.

[197] *Id.* (emphasis added).

Shell does not specify the time it will take to drill a relief well in the air permit application, but does conclude in its Beaufort Sea Oil Discharge Prevention and Contingency Plan (ODPCP)[198] that a blowout can be controlled using the M/V Discoverer within a 34 day period.[199]

We request that EPA revise permit Condition B2.3 to read:

> *A 34 day period must be reserved out of the total 168 operating period to drill a relief well. All exploratory well drilling (planned wells and sidetracks) must be completed within 134 days, reserving at least a 34 day period to drill a relief well. Any time spent drilling a relief well shall be included in the time recorded in Conditions B.2.2.3 and B.2.2.4. If the relief well exceeds a 34 day period, excess emissions must be reported.*

4. Sulfur content of diesel fuel.

EPA's proposed permit condition B.4 requires ultra-low sulfur fuel (15 ppm sulfur) on all emission units *except* the main propulsion engines (Unit FD-7). We request that the main propulsion engines be required to use ultra-low sulfur fuel (15 ppm sulfur) in accordance with EPA's June 6, 2006 Final Rule: Control of Air Pollution from Motor Vehicles and Nonroad Diesel Engines: Alternative Low-Sulfur Diesel Fuel Transition Program for Alaska.[200]

EPA's proposed permit condition B.4 requires testing to verify the ultra-low sulfur fuel (15 ppm sulfur) limit is met; however, EPA's proposed permit condition B.4.3 appears to allow Shell to burn fuel that exceeds the 15 ppm limit as long as any exceedance is reported to EPA. We request that proposed permit condition B.4.3 be revised to clarify that fuel that does not meet the 15 ppm standard cannot be used, and must be returned to the supplier. We do not find it acceptable to merely test the fuel sulfur content, and report any exceedances as a BACT approach. We request that EPA enforce its requirement to limit all actual fuel use to 15 ppm sulfur. Fuel that does not meet that standard should be returned to the supplier.

Condition B.4 should be revised to read:

> *The permittee shall not combust any liquid fuel with sulfur content greater than 0.0015 percent by weight, as determined by Condition B.4.1, in any emission unit on the Discoverer.*

Condition B.4.3 should be revised to read:

> *Fuel tests must verify the fuel sulfur content is 15ppm or less for that fuel to be used. Fuel exceeding 15ppm fuel sulfur must be returned to the supplier, unused.*

[198] A Chukchi ODPCP has not been provided for review at this time.
[199] Shell Beaufort Sea ODPCP at 1-26.
[200] 71 Fed. Reg. 32450-32464 (June 6, 2006).

EPA's proposed permit condition B.5 allows the fuel sulfur content for the ancillary vessels to be 0.19 percent by weight. Similarly, We request that the ancillary vessels be required to use ultra-low sulfur fuel (15 ppm sulfur) in accordance with EPA's June 6, 2006 Final Rule: Control of Air Pollution from Motor Vehicles and Nonroad Diesel Engines: Alternative Low-Sulfur Diesel Fuel Transition Program for Alaska.

Condition B.5 should be revised to read:

> *The permittee shall not combust any liquid fuel with sulfur content greater than 0.0015 percent by weight, as determined by Condition B.5.1, in support fleet engines.*

Condition B.5.3 should be revised to read:

> *Fuel tests must verify the fuel sulfur content is 15ppm or less for that fuel to be used. Fuel exceeding 15ppm fuel sulfur must be returned to the supplier, unused.*

EPA's June 6, 2006 Final Rule: "Control of Air Pollution from Motor Vehicles and Nonroad Diesel Engines: Alternative Low-Sulfur Diesel Fuel Transition Program for Alaska"[201] requires marine vessels to comply with a 15 ppm fuel sulfur standard on June 1, 2010. Shell's proposed 2010 operations, therefore, need to comply with this standard.[202] The final rule states:

> Beginning June 1, 2010, diesel fuel used in these applications must meet a 15 ppm (maximum) sulfur content standard.
>
> In 2010, highway and nonroad fuel in rural Alaska will be required to meet the 15 ppm sulfur standard, providing the full environmental benefits of these programs to rural Alaska as well.
>
> The permanent exemption from the 500 ppm sulfur standard of 40 CFR 80.29 for rural Alaska terminates on the implementation date of the new 15 ppm sulfur standard in 2006.
>
> On September 14, 2003, Alaska …requested that the ***15 ppm standard*** applicable to locomotive and ***marine diesel fuel produced in, imported into, and distributed or used within rural Alaska be moved up to June 2010,*** from the June 2012 date in the final nationwide NRLM rule.
>
> This rule specifies one exception to the nationwide NRLM standards and implementation deadlines in effect for diesel fuel produced in, imported into, and distributed or used within rural Alaska, beginning June 1, 2010. ***This exception is that*** locomotive and ***marine diesel fuel will also be required to meet the 15 ppm sulfur content standard on June 1, 2010*** rather than in 2012.

[201] 71 Fed. Reg. 32450-32464 (June 6, 2006).
[202] http://www.epa.gov/otaq/regs/fuels/diesel/420f06040.htm (Appendix IV).

> This rule further specifies that the 15 ppm sulfur standard applicable to locomotive and marine fuel (LM) be moved forward to 2010 to be implemented at the same time as the 15 ppm sulfur standard for nonroad (NR) diesel fuel. In this way there will only be one grade of NRLM[203] diesel fuel in the rural areas in 2010 and 2011 instead of two separate grades (i.e. 15 ppm and 500 ppm). The implementation dates for the NRLM diesel fuel sulfur standards are shown in Table II.B-1. [Table II.B-1 shows refiners and importers of fuel must meet the 15 ppm fuel sulfur standard on June 1, 2010.][204]

Additionally, we request that EPA require Shell to provide more information in its air permit application on the:

- fuel storage capacity for each vessel;
- which vessels (and capacity per vessel) will be used to resupply fuel;
- where the fuel transfers will occur; and
- the frequency of fuel transfers required.

EPA must account for any emissions associated with the resupply of fuel to the Discoverer and its associated fleet when within 25 miles of the drillsite and must ensure these emissions are clearly identified and included in the modeling analysis. It is not clear if the resupply ship (FD-31) includes fuel transfers or if other vessels will be needed for refueling.

5. Prohibited activities.

Permit condition B.8 prohibits flowing test wells, flaring gas and storing liquid hydrocarbons. This condition should also prohibit venting formation gas, and refueling within 25 miles of a drill-site unless those emissions are accounted for in the permit and BACT is applied.

6. EPA's proposed OCS/PSD permit must include requirements to ensure Shell is held to its representations regarding the exploratory drilling program that were made in its permit application.

EPA's proposed permit for Shell's exploration activities in the Chukchi Sea includes important provisions to ensure that the permitted sources cannot be modified from the source parameters that were reflected in Shell's complete PSD permit application. EPA's proposed permit specifies the date of the PSD permit application, descriptions of the proposed sources that include the individual make and model, as well as the rated capacity. We strongly support the inclusion of these provisions and references to the representations made in the permit application in order to ensure that Shell cannot change its operation in ways that could change air pollutant dispersion or alter BACT analyses without limitation. As an added measure, we suggest that EPA include a provision in the permit stating that operation of the permitted sources must be in accord with the information provided in the PSD permit application initially submitted by Shell Offshore Inc. on

[203] Nonroad, Locomotive and Marine (NRLM).
[204] 71 Fed. Reg. 32450-32464 (June 6, 2006) (emphasis added).

December 19, 2008, revised on February 23, 2009 and supplemented with the specific submittals identified in the administrative record for this permit action.

Further, EPA must require notification of any deviations from the information included in the permit application materials, and must make clear that any significant deviation from the representations made by Shell in its PSD permit application may be grounds for suspension or revocation of the permit. These types of permit provisions are commonly required in PSD permits, and provide a necessary assurance to the public and tribal, state and federal regulatory agencies that operation of significantly different sources, or significant modifications of the proposed sources, cannot occur without further evaluation.

Shell's application has been amended, corrected, supplemented numerous times since it was originally submitted in December 2008, making the application very cumbersome for the public to review, requiring the public to wade through thousands of pages of proposals, corrections and correspondence between Shell and EPA to determine what the application actually requests and to locate technical support data.

On September 17, 2009, over a month into the public comment period, Shell provided – yet further – additional corrections and supplements to its already unwieldy application and proposed submitting – even more – data at a later, yet to be determined date. As evidenced by Shell's latest revisions, Shell has yet to submit a complete, final permit application ripe for public review and comment. We request that Shell be required to correct and consolidate its permit application into one complete document that is more manageable for the general public to review.

We request that Shell's consolidated, corrected complete application, along with a revised EPA proposed permit and Statement of Basis addressing our concerns be provided for another 60 day public comment period.

B. Comments on the Ambient Air Quality Analysis and Supporting Data.

1. Ice management and anchor handling fleet.

EPA's proposed permit allows for the use of a generic ice management and anchor handling fleet. Under the proposed permit conditions, Shell can use a flexible number (one or two) of vessels that must meet generic parameters for capacity (see, e.g., Conditions N.1.1 through N.1.4 and O.1.1 through O.1.4), emission rates and limits for volume source release heights (e.g., Condition N.8). We are not convinced that merely capping the aggregate capacities of various vessel parameters, requiring the vessels meet certain emission rates for $PM_{2.5}$, PM_{10} and NO_x and requiring a minimum volume source release height is enough to ensure that the use of different vessels will be able to ensure compliance with NAAQS. EPA must require that Shell specify which Ice Management vessels it will use and establish permit limits and associated modeling requirements based on the use of these specific vessels.

The proposed permit requires stack testing of the support vessels to be completed prior to each drilling season (*see, e.g.*, Conditions N.9 and O.11), but does not specify how far in advance the testing must be done, nor does the permit include a remedy for failed tests.

Permit condition B.7.8 requires all stack test results to be provided to EPA within 45 days of testing. However, if stack testing only occurs a few days prior to the drilling season, there will not be adequate time to analyze and remedy any test results that exceed the permit limits before drilling starts. With a 168 operating day limit per drilling season, a quarter of the drilling season could pass before EPA even receives the test results. Permit conditions N.1.7 and O.1.7 requires Shell to notify EPA no later than 45 days prior to deployment to the Chukchi Sea of the ice management vessels selected. EPA requires 30 days notice on the testing which would appear to result in testing occurring as little as 15 days before the start of the drilling season. EPA must coordinate these timetables so that adequate time is allowed for to remedy any failed tests of the specified vessels

We request that EPA require all stack tests to be completed at least 180 days prior to each drilling season to ensure there is adequate time to analyze and remedy any test results that exceed permit limits. The permit must clearly state that any emission unit that fails to meet the permitted emission limit must not be operated until the unit is repaired or additional emission control is installed. Collecting test data, and merely reporting excess emissions if tests fail to meet permit limits, is not an acceptable solution, especially in the cases where the annual NO_x and 24-hour $PM_{2.5}$ NAAQS compliance margins are very tight. A failed test, unresolved, could result in a NAAQS exceedance.

We are also concerned that ice management activities may be underestimated in the permit analysis. This is important since the icebreaker activities represent a large portion of the overall emissions from the exploration activities. Specifically, the ice management vessels' activity accounts for more than 90 percent of PM emissions (and over 85 percent of NO_x emissions) from Shell's annual exploration drilling activities. The ice management vessels' emissions are dependant on ice conditions; heavier ice conditions result in heavier engine load factors and higher emissions. The Statement of Basis (p. 33) indicates that, "[b]ased on statistics on ice at the Sivulliq drill site in the Beaufort Sea, Shell estimates that ice breaking capability would only be required 38 percent of the time."

Assuming this is the same data used for the Camden Bay Exploration Plan, this estimate is based on 2003-2005 data.[205] The reference for this statement is a recent (2009) conversation between Air Sciences, Inc. and the "Arctic Wells Advisor" for Shell International Exploration and Production, Inc. Based on these data and this reference, it was assumed that there would be a 38% frequency of ice within 30 miles of the drillship. However, in its revised application to the US Coast Guard for safety zone designation, Shell characterized the ice conditions more recently than 2003-2005 as follows:

> Ice conditions during 2006 were such that the areas of drilling interest were ice covered the majority of the period between July and October. If ice conditions are

[205] Shell EP EIA Appendix H at 206

similar during 2007, then each drill rig will be constantly ice managed within its anchor array.[206]

This indicates that there is a strong possibility that the 38% frequency of ice may grossly underestimate emissions from the icebreaker vessels. EPA must secure an unbiased source of data for this important assumption – something other than an estimate from Shell of ice conditions. If the operator's estimate is based on a scientific analysis of ice flow data from 2003-2005 then that analysis should be made available and more recent data, if possible, should be incorporated into the analysis. The icebreaker vessels' emissions must be modeled to account for the maximum potential operation scenario under maximum ice conditions for the relevant time of year. We request that the emissions be recalculated based on full time ice management, the modeling be rerun and both be provided for public review.

2. Oil spill response.

EPA does not address the potential air impacts from sources associated with potential oil spills in this permit. There are emissions estimates for oil spill response vessels in the inventory to account for emissions from these vessels associated with training and drills but EPA does not directly address the potential ambient air quality impacts from the pollutants that will occur in the event of an oil spill. The details of an oil spill response and ensuing emissions are known and therefore we ask that EPA consider these potential emissions along with Shell's potential to emit. We would like to see EPA complete a full evaluation of the potential air quality impacts from an oil spill scenario, including VOC and HAP emissions from evaporation, $PM_{2.5}$ and PM_{10} emissions from in-situ burning during cleanup operations and combustion emissions (NO_x and PM) from vessels during the response. Alternatively, EPA should clarify the applicability of USCG and ADEC guidelines and rules to Shell's operations (*e.g.*, related to spill scenarios for in-situ burning, etc.) and how these will ensure protection of human health in the event of an oil spill.

If EPA will not be addressing an emergency oil spill response event directly in this permit then it needs to address how attainment of the NAAQS will be assured for this particular Air Quality Control Region (AQCR), in general. The CAA Section 110 requirements for States to prepare State Implementation Plans (SIPs) that detail provisions for attainment and maintenance of the NAAQS in the Air Quality Control Regions (AQCR) under its jurisdiction do not apply to the AQCR where Shell proposes to conduct its exploratory drilling program. EPA must clearly explain how it will be ensuring attainment of all NAAQS in this AQCR in the absence of a SIP for the region. Specifically, EPA must address how the enforceable measures of a Federal Implementation Plan may be needed in order to establish contingency plans for air pollution emergencies, such as may occur during an oil spill.

3. Hazardous Air Pollutants (HAPS).

[206] Letter from Susan Childs, Regulatory Affairs Coordinator – Alaska, Shell Offshore Inc. to United States Coast Guard, District 17 at 2 (May 30, 2007), regarding the establishment of safety zones for the Frontier Discoverer drill ship and the semi-submersible drill unit Kulluk in the Beaufort Sea, Alaska.

The proposed permit is based on total hazardous air pollutant emissions from the proposed exploration drilling program of 3.5 tons per year, as quantified in Shell's permit application materials. Shell's estimates are based on "requested limits and other limits assumed under the permit application and supporting materials submitted to EPA."[207]

The emissions calculations included in Shell's application materials show HAP estimates for units FD-1 through FD-22, the ice management fleet and the OSR fleet. There are no HAP emissions estimates for the incinerator (FD-23), the fuel tanks (FD-24 through FD-30), the drilling mud system (FD-32) and the shallow gas diverter system (FD-33).[208] EPA must prepare a more comprehensive inventory and include estimates for individual HAPs as well as an assessment of total HAP emissions from all sources combined.

4. Background concentrations

EPA and Shell are relying on data collected at the monitoring station in Wainwright, Alaska as representative of background concentrations for the Shell exploratory drilling program. The Wainwright station was established by ConocoPhillips Alaska, Inc. in late 2008 for the purposes of collecting pre-construction monitoring data for future permit applications. EPA is accepting data collected to-date from the Wainwright station in fulfillment of the preconstruction monitoring requirement of 40 CFR § 52.21(m). EPA justifies the use of these data as representative of background concentrations for Shell's exploratory drilling program, as follows:

> Wainwright is a rural area with few combustion sources and arctic weather conditions similar to those of the Chukchi Sea. EPA believes that the location of the Wainwright monitoring station is representative of air quality in the area covered by Shell's leases in Lease Area 193 because of the relative closeness of Wainwright to the Shell leases, the relative lack of air pollution sources in Wainwright and the area covered by Shell's leases, and the relative similarity of the meteorology in Wainwright and the area covered by Shell's leases.[209]

EPA has approved the use of the SO_2, NO_2, NO_x, NO, CO, and O_3 gaseous measurements and PM_{10} data collected from November 8, 2008 to June 30, 2009 as appropriate for use as representative background air quality levels for this proposed permitting action.[210] EPA's regulations require at least one year of pre-construction monitoring data unless "the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months)."[211] Instrumentation problems rendered all $PM_{2.5}$ data collected from November 8, 2008 through March 5, 2009 invalid. According to EPA:

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[207] EPA Stmt of Basis at 18.
[208] *See* EPA Stmt of Basis at Section 4.5; *see also supra* at 32.
[209] EPA Stmt of Basis at 74.
[210] *Id.* at 75.
[211] 40 C.F.R. § 52.21(m)(1)(iv).

> The [$PM_{2.5}$ instrumentation] problem has since been addressed. USEPA 2009b. PM2.5 data collected from March 6, 2009 through June 30, 2009 does meet the requirements of the EPA approved monitoring plan, but does not at this time satisfy the requirement of 40 CFR Part 51, Appendix A, § 3.2.5.5, and 40 CFR § 51.21(m)(3), which requires co-located Federal Reference Method (FRM) and Federal Equivalent Method (FEM) PM2.5 samplers at one of the PSD network monitoring stations. Shell is in the process of establishing co-located monitors at one of the PSD network monitoring stations.[212]

Therefore, the minimum requisite four months of $PM_{2.5}$ data has not been obtained. EPA must make clear when the co-located samplers were established and must count the four months of monitoring data from that date.

For PSD monitoring, EPA should require collocation at least at one site in the network[213] operating one-in-six days for a sampler operating on a one-in-three day schedule, or one-in-three days for a sampler running every day.[214] EPA must also require quarterly Performance Evaluation Program (PEP) audits of 100 percent of the network every quarter.[215] Since PSD monitoring sites operate for such a short relative period, it is extremely important to have tight Quality Assurance controls. These requirements should be spelled out in the Quality Assurance Project Plan (QAPP) written by the monitoring organization and approved by the overseeing entity (in this case, the Region). EPA must clearly identify the expectations for how the data being gathered will be used, and what is allowable for the precision and bias values in order to be able to apply the data with a reasonable level of confidence.

It is important to point out that the available $PM_{2.5}$ data, while they do not meet the requirements for co-located samplers, also do not correspond to the same months of operation as covered by Shell's exploration drilling program. EPA must provide further justification as to why data collected from a different part of the year is representative of background concentrations during the proposed exploration activities or why the available data are more conservative that what would be expected during the project time period.

In fact, it does not appear that this is the case. Shell has submitted recent monitoring data collected at the Wainwright monitoring station through July 31, 2009 to EPA (September 17, 2009) which include higher recorded values than any others included in the previous record. Specifically, 24-hour average $PM_{2.5}$ concentrations collected in July include no less than eight days where the maximum recorded 24-hour average concentration was equal to or greater than the background concentration of 8 $\mu g/m^3$ used in EPA's and Shell's ambient air impact analysis. The highest 24-hour average concentration from July of 14 $\mu g/m^3$ is 75% higher than the background concentration used in the permit analysis. In fact, use of any of the top three monitored concentrations as representative background concentrations in EPA's ambient air

[212] EPA Stmt of Basis at 75.
[213] 40 C.F.R. § 58 Appendix A §3.2.5.5.
[214] 40 C.F.R. § 58 Appendix A §3.2.5.7.
[215] 40 C.F.R. § 58 Appendix A §3.2.7.

analysis would result in modeled violations of the 24-hour $PM_{2.5}$ NAAQS.[216] As written, *the proposed permit does not ensure compliance with the short-term $PM_{2.5}$ NAAQS* when considering the most recent data from the Wainwright monitor.

The fact that EPA's and Shell's modeling cannot demonstrate compliance with the NAAQS using more recent data from the Wainwright monitor – and that was collected during a month that corresponds to the same time of year covered by Shell's proposed operations – poses serious questions with respect to EPA's determination. In particular, we are concerned with EPA's decision to accept: (1) minimal pre-construction $PM_{2.5}$ monitoring data; (2) data collected outside the time period being permitted; and (3) data not based on EPA's own monitoring requirements for operating co-located samplers. EPA must require a complete monitoring record that covers at least the time period for which the permit will be issued. This same issue was raised to Shell in 2007[217] when we requested additional site-specific monitoring data to be collected for their proposed exploratory drilling program; Shell has had adequate time to collect the data. There are no short cuts for failing to collect an adequate amount of pre-construction monitoring data and Shell must be held to the same regulatory standards as all other applicants. If the monitoring data collected at the Wainwright station are not considered representative of background concentrations for Shell's proposed exploration activities then EPA must require Shell to collect the requisite data *before* issuing a final permit.

In fact, EPA is requiring that Shell collect monitoring data through December 2009 for its proposed exploration drilling program in the Beaufort Sea for the very same reasons argued here and has not deemed the permit application complete as a result of this, and other, deficiencies in Shell's application. Following is an excerpt from EPA's September 4, 2009 incompleteness letter highlighting these issues:

> Recently provided data from Wainwright shows nine 24-hour periods of PM2.5 measurements equal to or greater than the 8.0 micrograms per cubic meter during the months of July and August, 2009, with the highest measured concentration at 14.42 micrograms per cubic meter. The 8.0 micrograms per cubic meter for a 24-hour average was measured in June, 2009. After its initial review and consideration of all the PM 2.5 24-hour measurements from 06 March 2009 to 31 August 2009 at Wainwright, ***EPA now believes it is prudent to extend the PM2.5 data collection at Wainwright and Badami such that the measurements include the months that SOI intends to conduct exploratory drilling operations***. This would be the months of July to December for the SOI Beaufort Sea OCS PSD

[216] EPA Stmt of Basis, Appendix B, Table 12a shows a max modeled 24-hour average concentration for $PM_{2.5}$ of 25.7 $\mu g/m^3$ (SOS #1). Considering the top three monitored concentrations at Wainwright, total predicted concentrations are as follows:

25.7 $\mu g/m^3$ + 14 $\mu g/m^3$ = 39.7 $\mu g/m^3$ (113% of 24-hour $PM_{2.5}$ NAAQS)
25.7 $\mu g/m^3$ + 13 $\mu g/m^3$ = 38.7 $\mu g/m^3$ (111% of 24-hour $PM_{2.5}$ NAAQS)
25.7 $\mu g/m^3$ + 11 $\mu g/m^3$ = 36.7 $\mu g/m^3$ (105% of 24-hour $PM_{2.5}$ NAAQS)

[217] Letter from Johnny Aiken, North Slope Borough, to Natasha Greaves and Dan Meyer, EPA Region 10 (May 11, 2007) (Appendix IV).

> permit application. [The Chukchi Sea OCS PSD permit application is for the same time period.]
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> In addition, Appendix A in 40 CFR Part 58 requires collocated PM 2.5 sampling at the monitoring station or at one of the PSD network monitoring stations. The monitoring stations at Wainwright and Badami currently are not operating a collocated sampler. In summary***, SOI is requested to submit PM2.5 measurements representative of the months of July to December which meets the requirements contained in paragraph (m)(3) in 40 CFR Part 52.21 and Appendix A of 40 CFR Part 58.***[218]

The fact that EPA's proposed permit for Shell's exploratory drilling program in the Chukchi Sea includes a requirement for post-construction monitoring of $PM_{2.5}$ (Condition R.1) undercuts the Agency's argument that sufficient pre-construction monitoring data exist. It is the EPA's responsibility to require that Shell collect the needed data up-front; the permit process must not proceed without sufficient data that satisfy all EPA's regulatory obligations.

5. Secondary $PM_{2.5}$ formation.

An important consideration in determining $PM_{2.5}$ impacts, which is not accounted for in the modeling for this proposed permit, is the assessment of secondary $PM_{2.5}$ formation in the atmosphere. In addition to primary $PM_{2.5}$ emissions (directly emitted from combustion point sources and from fugitive sources), emissions of NO_x, VOCs, SO_2 and ammonia can form, after being emitted into the atmosphere, into $PM_{2.5}$ and this can potentially be a significant component of ambient $PM_{2.5}$ concentrations.[219] And while primary $PM_{2.5}$ emissions are generally a localized issue, secondary $PM_{2.5}$ emissions can be more regional in scale. Secondary $PM_{2.5}$ formation could be especially important considering the fact that the modeling results presented in the Statement of Basis, Appendix B, predict $PM_{2.5}$ concentrations at over 96% of the 24-hour NAAQS.[220]

The fraction of $PM_{2.5}$ concentrations in the ambient air that is due to the secondary formation of $PM_{2.5}$ (e.g., sulfates and nitrates), as opposed to directly emitted [primary] $PM_{2.5}$ (e.g., as a product of combustion) is dependent on many factors. However, the presence of strong temperature inversions that limit dispersion contribute to the formation of secondary $PM_{2.5}$ in the atmosphere and can increase secondary $PM_{2.5}$ formation. $PM_{2.5}$ concentrations, therefore, can be due to gaseous pollutants that form fine particles after reacting with other compounds in the air during meteorological inversions and it is important for EPA to consider these $PM_{2.5}$ precursor sources (*e.g.*, NO_x from the diesel combustion sources associated with Shell's exploration drilling program) in its ambient air quality impact analysis. Because of the presence of strong

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[218] Letter from EPA to Shell, Re: Incompleteness Determination for Outer Continental Shelf Pre-Construction Air Permit Application for the Frontier Discoverer Beaufort Sea Exploration Program, at 11-12 (Sept. 4, 2009) (Appendix IV) (emphasis added).

[219] *See* http://www.epa.gov/ttnnaaqs/pm/presents/policies_for_pm25_precursors-rich_damberg.ppt

[220] EPA Stmt of Basis at Appendix B Table 12a.

temperature inversions on the North Slope, EPA must seriously consider the contribution from secondary $PM_{2.5}$ to total $PM_{2.5}$ concentrations from the permitted sources.

EPA must address how it will account for secondary $PM_{2.5}$ impacts from the permitted sources. EPA's Support Center for Regulatory Atmospheric Modeling (SCRAM) provides various resources for modeling the impacts of secondary $PM_{2.5}$. For example, EPA's recently-developed model based on the Community Multi-scale Air Quality (CMAQ) model in support of the development of the $PM_{2.5}$ NAAQS has been shown to "reproduce the results from an individual modeling simulation with little bias or error" and "provides a wide breadth of model outputs, which can be used to develop emissions control scenarios".[221] The Comprehensive Air quality Model with extensions (CAMx) is another tool available to assess secondary $PM_{2.5}$ formation. CAMx has source apportionment capabilities and can assess a wide variety of inert and chemically reactive pollutants, including inorganic and organic $PM_{2.5}$ and PM_{10}. The Regional Modeling System for Aerosols and Deposition (REMSAD) can also model concentrations of both inert and chemically reactive pollutants on a regional scale, "including those processes relevant to regional haze and particulate matter".[222] These are just some examples of current models, identified by EPA, with the capability to assess secondary $PM_{2.5}$ impacts.

EPA must use account for the secondary $PM_{2.5}$ formation from permitted sources. The secondary $PM_{2.5}$ component could be critical to understanding the best way to mitigate potential $PM_{2.5}$ impacts.

6. Impacts to regional Ozone.

EPA failed to complete any analysis of the proposed exploratory drilling program's impacts on ozone concentrations in the region. EPA justifies this, as follows:

> Because NO_x and VOC net emissions exceed 100 tons per year, Shell is required under the 40 CFR § 52.21(i)(5) to perform an ambient air quality impact analysis, including gathering ambient air measurements, of ozone. Ozone is formed in atmosphere through a chemical reaction that includes NO_x, VOC and CO in the presence of sunlight. The sources of these air pollutants are mainly combustion sources such as power plants, refineries and automobiles. Over the past ten years, monitoring programs have measured ozone and ozone precursors (i.e., NO_x and VOC) on the North Slope in the area where the oil and gas operations are currently located. Ozone levels at these locations are higher than the levels that have been collected at the Wainwright monitoring site. Shell expects to emit approximately 2818 tons per year of NO_x and roughly 107 tons per year of VOC ozone precursor emissions. These precursor emissions and it contribution to the formation of ozone is expected to be small."[223]

Yet EPA presents no analysis (qualitative, or otherwise) to support such a statement that

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[221] *See* http://www.epa.gov/scram001/reports/pmnaaqs_tsd_rsm_all_021606.pdf (Appendix IV).
[222] *See* http://remsad.saintl.com/ (Appendix IV).
[223] EPA Stmt of Basis at 76.

contribution to ozone formation from this project is expected to be small. The atmospheric chemistry leading to ozone formation is complex and is highly sensitive to a wide range of factors, including the intensity of sunlight, air temperature and the quantity and chemical composition of the volatile organic compounds (VOC) and nitrogen oxide (NO_x) pollutants that combine in the presence of sunlight to form ozone. For these reasons, EPA should not simply dismiss the issue without more detailed justification. EPA must more thoroughly address the potential regional ozone impacts from the permitting actions of large air pollution sources on the OCS as it continues to receive applications for exploration activities.

Traditionally, elevated ozone levels are thought to be a summertime problem that plagues large urban areas. However, "recent events that have occurred in rural southwest Wyoming in wintertime demonstrate this is not always the case."[224] This raises a potential concern with respect to potential regional ozone formation on the North Slope of Alaska during the non-summer months. According to a recent study by the National Oceanic and Atmospheric Administration, ozone rapidly formed in southwest Wyoming "when three factors converged: ozone-forming chemicals from the natural gas field, a strong temperature inversion that trapped the chemicals close to the ground, and extensive snow cover, which provided enough reflected sunlight to jump-start the needed chemical reactions." [225] The North Slope of Alaska also exhibits these three factors needed for ozone formation. First, industrial sources in the North Slope region have the potential to contribute tens of thousands of tons of NO_x emissions (80,000 TPY) and several thousand tons of VOC emissions (2,500 TPY) to the area each year.[226] These sources and Shell's proposed OCS activities are all contained within an area similar in size to a representative regional ozone study domain (e.g., 400-500 km by 400-500 km). In comparison, the NO_x inventory for the counties that include the Wyoming development field totals just over 60,000 TPY and VOC emissions total just over 10,000 TPY.[227]

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[224] WYDEQ Sublette County Air Quality Information Page, *see e.g.*, http://deq.state.wy.us/out/downloads/PINEDALE%20April%2008%20Town%20Meeting.pdf); *see also* http://www.starvalleyindependent.com/2009/03/governor-concerned-over-southwest-wyoming-ozone-levels/.

[225] *See* NOAA's press release (available at: http://www.noaanews.noaa.gov/stories2009/20090118_ozone.html), January 18, 2009 for Schnell, R.C., et al. 2009. Rapid photochemical production of ozone at high concentrations in a rural site during winter. *Nature Geoscience* 1-3 (January 18, 2009) (available at: http://www.nature.com/naturegeoscience) (Appendix IV).

[226] *See* the North Slope Borough Region Emission Summary in Table 3.4.5-8 of the Beaufort Sea and Chukchi Sea Planning Areas Oil and Gas Lease Sales 209, 212, 217, and 221 Draft Environmental Impact Statement, OCS EIS/EA MMS 2008-0055. Total permitted NOx emissions exceed 83,000 TPY and total permitted VOC emissions exceed 2,500 TPY (available at: http://www.mms.gov/alaska/ref/EIS%20EA/ArcticMultiSale_209/2008_0055_deis/vol4k5.pdf)(Appendix IV).

[227] Based on 2005 emissions data presented in meeting notes from Greater Yellowstone Area Clean Air Partnership Annual Meeting, Pocatello, ID, October 17-18, 2007 (available online at http://www.fs.fed.us/r1/gallatin/resources/air/gyacap/docs/GYACAP-Pocatello_2007_Meeting_Notes.doc) (Appendix IV).

Second, strong temperature inversions frequently occur in Alaska's North Slope region. Finally, extensive snow cover is persistent in the region from as early as September through June.[228] The Chukchi and Beaufort Seas exploration activities will occur, at least in part, during this period. While there may not be available sunlight in the dead of winter there is certainly abundant sunlight in the fall and spring in conjunction with snow cover and strong temperature inversions. The fact that the pollution sources and photochemical mechanisms for producing ozone are available and the possibility of elevated background concentrations from global transport of pollution is real means that EPA must more thoroughly investigate the effects of NO_x and VOC sources from the proposed exploration activities on the OCS and from existing and reasonably foreseeable NO_x and VOC sources in the region on ozone formation on the North Slope.

Even though monitored levels of ozone from the Wainwright monitor do not threaten compliance with the NAAQS, background concentrations as high as 50 ppb have been observed.[229] This level is equivalent to background concentrations currently observed in the active oil and gas development areas in the Uinta Basin in northeast Utah.[230] EPA has a regulatory obligation to ensure compliance with the NAAQS. Emissions will dilute as they transport away from their source of origin, but spreading of plumes is not always rapid and is highly dependent on the atmospheric stability at the time. Emissions from Shell's activities could certainly contribute to ozone formation in the region under the right conditions, as described above.

A study looking at future ozone concentrations in the Arctic from increased shipping traffic in the Arctic northern passages determined that ships' combustion engines could increase ozone concentrations in the region by 2-3 times in the decades ahead (with predicted peak concentrations reaching more than 60 ppb_v in July and August). [231] According to the same study, "the photochemical lifetime of ozone [in the Arctic] is rather long, and its deposition velocity on ice and water is small." Furthermore, "[i]n most regions of the troposphere, including the remote Arctic areas where background concentrations of pollutants are particularly low, the formation rate of ozone is limited by the amount of nitrogen oxides that are present in the atmosphere." Thus, it is conceivable that NO_x (and VOC) emissions from Shell exploration activities in the Chukchi and Beaufort Seas could contribute to elevated ozone concentrations in the region, even during the summer months.

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[228] *See, e.g.*, the Barrow Snowmelt Date study performed by NOAA's Earth System Research Lab (available at http://www.esrl.noaa.gov/gmd/grad/snomelt.html) (Appendix IV).

[229] EPA Stmt of Basis, Appendix B, Table 8 shows representative background concentrations for ozone (8-hr average) of 96 $\mu g/m^3$. 1 ppb = 1 $\mu g/m^3$ * 24.45 / MW so 96 $\mu g/m^3$ * 24.45 / 48 = 49 ppb

[230] Background ozone concentrations in the Uinta Basin, Utah from recent (2008) EAs = 50 ppb (draft Big Pack EA UT-080-06-488, draft River Bend EA UT-080-07-772, draft Southam Canyon EA UT-080-08-342) (available at: http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_.html).

[231] Granier, C., U. Niemeier, J. H. Jungclaus, L. Emmons, P. Hess, J.-F. Lamarque, S. Walters, and G. P. Brasseur (2006), Ozone pollution from future ship traffic in the Arctic northern passages, *Geophys. Res. Lett.*, *33*, L13807, doi:10.1029/2006GL026180 (available at: http://www.agu.org/pubs/crossref/2006/2006GL026180.shtml) (Appendix IV).

In order to fulfill its regulatory responsibilities to ensure compliance with all NAAQS, EPA must include a more thorough evaluation and discussion of potential ozone impacts in the region from ongoing permitting activity on the OCS.

V. EPA Must Ensure That Other Applicable Environmental Laws And Requirements Are Met Before A Clean Air Act Permit Is Issued To Shell.

Prior to the issuance of any permit to Shell, there are several environmental laws that must be complied with.

A. A National Environmental Policy Act Review is Required Before Shell is Allowed to Explore for Hydrocarbons in the Chukchi Sea.

The National Environmental Policy Act (NEPA) is our Nation's "basic national charter for protection of the environment."[232] NEPA declares a national policy "to enrich the understanding of the ecological systems and natural resources important to the Nation,"[233] and makes it the "continuing responsibility" of all federal agencies to "preserve important historic, cultural, and natural aspects of our national heritage . . .." *Id.* § 4331(b)(4).

Shell's PSD permit application is related to the company's exploration plans in the Chukchi Sea. Shell is currently proposing exploratory operations in both the Chukchi and Beaufort Seas with very similar environmental impacts. We have asked the Minerals Management Service (MMS) to analyze the impacts from these two Exploration Plans together under the National Environmental Policy Act (NEPA). We request that EPA exercise its authority to provide review and feedback on this or any other related NEPA process.[234]

Acknowledging the hefty work load Region 10 already has, we ask that whenever possible the EPA provide assistance to MMS in analyzing and reviewing the impacts to air and water resources from proposed off-shore drilling operations in the Arctic. In the past, MMS has simply deferred to EPA's permitting processes in its NEPA documents instead of actually analyzing the air and water impacts from off-shore oil and gas activities and we unfortunately have little reason to believe this approach will change. Thus, we ask for EPA's assistance in ensuring such analyses are performed and made available to the public for comment.

B. EPA Must Conduct an Environmental Justice Analysis before Making a Decision on Shell's Permit Application.

[232] 40 C.F.R. § 1500.1(a).
[233] 42 U.S.C. § 4321.
[234] 40 C.F.R. § 52.21(s) ("[w]henever any proposed source or modification is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act, review by the Administrator conducted pursuant to this section shall be coordinated with the broad environmental reviews under that Act and under section 309 of the Clean Air Act").

Under Executive Order No. 12898, EPA must consider and address, when appropriate, "disproportionately high and adverse human health and environmental effects of [their] programs, policies, and activities on minority and low-income populations."[235] When issuing PSD permits, the EAB has required that the permitting agencies provide details about the required environmental justice analysis.[236] Thus, the EPA must conduct an environmental justice analysis to determine the environmental implications of Shell's operations.

In the statement of basis for the draft permit, EPA recognizes that the Alaskan Natives, a minority population, make up a significantly large portion of the potentially impacted communities.[237] As previously discussed in section III, Shell's operations will contribute to global warming effects that will harm the Arctic and threaten the livelihood of those native communities.

EPA has found that there are human health hazards associated with exposure to diesel exhaust. In the *Health Assessment Document for Diesel Engine Exhaust*, EPA explained that some of these health hazards include "acute exposure-related symptoms, chronic exposure related noncancer respiratory effects, and lung cancer."[238] Notably, EPA found that diesel engine exhaust is "likely to be carcinogenic to humans by inhalation" through environmental exposures.[239] EPA must consider whether or how these human health hazards will affect the native communities that are on-shore from Shell's operations.

EPA cannot rely upon Shell's compliance with the NAAQS to determine that Shell's air emissions will not harm human health and welfare. Even though the NAAQS are supposed to protect human health with an adequate margin of safety, CAA § 109(b),[240] the standards often do not. EPA has failed to update the NAAQS every five years as required, thus the NAAQS do not always reflect the current state of technological and scientific knowledge about criteria pollutants. Even when EPA revises the NAAQS, the agency does not always adopt the most protective standard recommended by the Clean Air Scientific Advisory Committee to protect human health and welfare. In fact, the U.S. House Committee on Oversight and Government Reform documented how political considerations trumped health recommendations in the March 2008 determination of the NAAQS for Ozone.[241]

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[235] *See* Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7,629, 7,632-33 (Feb. 11, 1994).
[236] *See In re: Knauf Fiber Glass*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 175 (1999) (remanding PSD permit to the permitting agency to include the environmental justice analysis in the record).
[237] EPA Stmt of Basis at 83.
[238] Available at http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=29060 at 1-3(May 2002) (Appendix V).
[239] *Id*. at 1-4 and 1-5.
[240] 42 U.S.C. § 7409(b).
[241] *See* Memo Re: Supplemental Information on the Ozone NAAQS, May 2008 (available at oversight.house.gov/documents/20080520094002.pdf) (Appendix V).

Particulate matter provides a compelling example that the NAAQS are insufficient to protect public health. In the most recent revision of the NAAQS for PM, EPA documented the health problems associated with exposure to particulate matter, including chronic respiratory disease, asthma, lung cancer, and cardiorespiratory mortality.[242] EPA found that epidemiological studies revealed a linear relationship between health problems, notably cancer, and the ambient concentration of particulate matter. EPA could not determine a threshold for particulate matter concentrations under which no human health effects would occur.[243] This evidence suggests that any level of particulate pollution will have human effects, thus the PM NAAQS is not protective of human health.

Due to the unreliability of the NAAQS, EPA cannot conclude that Shell's purported compliance with the NAAQS will protect the health and welfare of the native communities in the surrounding area. Thus, EPA must conduct an independent analysis to determine the impact of Shell's activities on the health and welfare of the native communities in the Chukchi Sea.

C. EPA Needs to Consult with FWS and NMFS under Section 7 of the Endangered Species Act.

The Endangered Species Act (ESA) was enacted to provide "a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved . . . [and] a program for the conservation of such endangered species and threatened species . . . ."[244] The Supreme Court has explained that "the plain intent of Congress . . . was to halt and reverse the trend toward species extinction, whatever the cost."[245]

Section 7(a)(2) of the ESA requires every federal agency in consultation with the Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) to "insure" that its actions are "not likely to jeopardize the continued existence of any endangered species" or result in the adverse modification of listed species' designated "critical habitat."[246] As the EAB has explained, "most importantly, '[a]fter meaningful consultation" with the Service, it is the federal agency who "possesses the ultimate decisionmaking authority to determine whether it may proceed with an action.'"[247] Once consultations have commenced, section 7(d) of the ESA prohibits "any irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures."[248]

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[242] *See* EPA National Ambient Air Quality Standards for Particulate Matter; Final Rule. 71 Fed. Reg. 61144, 61154 (Oct. 17, 2006).
[243] *See* EPA National Ambient Air Quality Standards for Particulate Matter; Proposed Rule, 71 Fed. Reg. 2620, 2635.
[244] 16 U.S.C. § 1531(b).
[245] *TVA v. Hill*, 437 U.S. 153, 184 (1978).
[246] 16 U.S.C. § 1536(a)(2); *Thomas v. Peterson*, 753 F.2d 754, 763 (9th Cir. 1985).
[247] *In re: Desert Rock Energy Company LLC,* Slip Op. at 37 (quoting *Pac. Rivers Council v. Thomas*, 936 F. Supp. 738, 744 (D. Idaho 1996)).
[248] 16 U.S.C. § 1536(d); *see also In re: Desert Rock,* Slip Op. at 38-39.

Shell's proposed operations include significant air emissions. The Discoverer's emissions alone include an estimated 22,000 tons of CO_2 per year,[249] and the combined emissions of Shells' operations include significant quantities of PSD pollutants.[250] Not only will these emissions contribute to global climate change – which has led to the listing of several Arctic species under the ESA – but they may threaten marine habitat as discussed below, *see supra* at *, regarding the need for a new soil and vegetation analysis.

Additionally, Shell's proposed operations have great potential to impact ESA listed species. Our whaling captains and Inupiat elders have long expressed their concern that bowhead whales are extremely sensitive to ocean discharges as they have very strong olfactory senses and can easily detect contaminants in the water column. The deposition of air pollutants from Shell's proposed operations have a strong likelihood of causing bowhead whales to avoid the areas where the pollutants are being deposited. Wind and air currents in the Chukchi Sea need to be taken into consideration in determining the areas that will be impacted and the ensuing impacts to bowhead whales need to be analyzed before Shell is issued a permit. It is not sufficient for EPA to rely on consultations for other projects,[251] in light of *its* statutory obligation to ensure that "any action" it authorizes will not "jeopardize the continued existence of any" listed or adversely modify its critical habitat.[252]

The ramifications of Shell's emissions on the Chukchi Sea environment and the marine life therein must be consulted on with the FWS and NMFS before a permit is issued to Shell.[253] Given the potential impacts of Shell's proposed actions and the need for additional analysis of the fragile Arctic environment, section 7 consultations should have been completed "prior to the comment period on the permit" because that is when EPA has the greatest "flexibility to address ESA concerns is the greatest."[254] We request that the EPA explain why it elected not to complete the section 7 consultation process before providing a draft permit for public comment.

VI. Shell Submitted An Incomplete Application That Is Inconsistent With Information It Has Provided To Other Federal Agencies About Its Proposed Operations.

The EPA's regulations provide that the owner or operator of an OCS source "shall submit to the [EPA] all information necessary to perform any analysis or make any determination required under this section."[255] Here, Shell has submitted a permit application that is incomplete and

[249] Shell EP EIA at 36-37,
[250] *See supra* at 3.
[251] *See* EPA Stmt of Basis at 81.
[252] 16 U.S.C. § 1536(a)(2).
[253] *See In re: Indeck*, Slip Op. at 110-11, 13 E.A.D. at --- (Sept. 27, 2006) ("the Agency should complete the ESA process prior to the issuance of the final permit. This ensures that, if FWS recommends any changes to the permit during the consultation process or, alternatively, if EPA decides to add or amend permit conditions based on any information or findings that arise during the ESA consultation process, such changes may be implemented in the final PSD permit." (internal citations omitted)).
[254] *In re: Desert Rock Energy*, Slip. Op. at 39 (quoting *Indeck*, at 114)).
[255] 40 C.F.R. § 55.6(a)(1)(i).

inconsistent with its representations to other agencies. For these reasons, Shell should not receive a permit until it can fully describe its proposed activities in an accurate manner.

For example, Shell is required to provide "[a] detailed description as to what system of continuous emissions reduction is planned for the source or modification, emission estimates, and any other information necessary to determine that best available control technology would be applied."[256] In light of the numerous changes Shell has proposed to its operations, it is difficult to discern whether these requirements have been met or not.

Pursuant to its own regulations, EPA is not allowed to process "a permit until the applicant has fully complied with the application requirements for that permit."[257] Because Shell has not demonstrated compliance with EPA's application requirements, we ask that it not be issued a permit at this time.

A. Shell's Monitoring Data is Inadequate.

The monitoring data Shell is using to support its application is incomplete and inadequate for several reasons. First, Shell has not collected monitoring data within even 25 miles of where it is proposing to explore for oil and gas.[258] The data provided in support of a permit application must be representative of actual conditions at the project site.[259]

Second, Shell has not collected the requisite year's worth of data and neither EPA nor Shell has provided an adequate explanation for using less than a year of data. This practice fails to meet the requirement that "analysis shall contain continuous air quality monitoring data."[260]

Shell has provided monitoring data from ConocoPhillips[261] for SO_2, NO_2, NOx, NO, CO, and O_3 and PM_{10} from November 8, 2008 to July 30, 2009.[262] Eight months worth of data is insufficient particularly where the data does not even cover all the months that Shell is anticipating operating in the Chukchi Sea – *i.e.*, August, September, October, and November. In connection with Shell's OCS PSD application for operations in the Beaufort Sea, EPA explained that the data "at a minimum, should represent the [Shell] drill season months July to December, so EPA can be

[256] 40 C.F.R. § 52.21(n)(1)(iii).
[257] 40 C.F.R. § 124.3(a)(2).
[258] *See* Shell Chukchi Sea EP at 3; EPA Stmt of Basis at 74.
[259] *See* 40 C.F.R. § 51, App. W sec. 8.2.1(b), 8.3(a).
[260] 40 C.F.R. § 52.21(m)(1)(iii); *see also* EPA, Ambient Monitoring Guidelines at 6 (requiring applicants to conduct "monitoring" "for at least 1 year prior to submission of the application to construct").
[261] We point out that this data was collected by Conoco Phillips only because it is a subset of a much larger data set that ConocoPhillips is collecting to support a PSD permit application that it anticipates submitting in the future. These efforts by ConocoPhilips demonstrate that with proper planning a more sufficient data set can be collected.
[262] *See* EPA Stmt of Basis at 74; 3d Quarter Data Report May-July 2009 (submitted Sept. 18, 2009).

reasonably assured there won't be a NAAQS violation."[263] Moreover, ConocoPhillips' data is also far from continuous as demonstrated by its monitoring reports.[264] Moreover, with respect to $PM_{2.5}$, it is unclear whether Shell has yet to provide *any* adequate data, *see supra* at *.[265]

This is significant because, as EPA recognized, "[t]he monitoring state at Wainwright is the first site on the North Slope with a $PM_{2.5}$ monitor."[266] Until adequate $PM_{2.5}$ data is collected, there is no basis for making any assumptions about the baseline $PM_{2.5}$ levels on the North Slope. EPA needs to explain the assumptions it is making about $PM_{2.5}$ levels and why they are valid. The need for additional data especially for $PM_{2.5}$ should result in a decision that Shell's permit cannot be issued at this time.

We also question why EPA concluded that Shell's Chukchi PSD permit was complete based on the data as described above, but determined that Shell's Beaufort PSD permit application was not complete when it had similar (although admittedly even more substantial) monitoring problems.[267] EPA needs to explain this discrepancy.

B. Shell's Soil and Vegetation Analysis is Insufficient.

EPA requires PSD permit applicants to "provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source" and impacts associated with the source.[268] Here, Shell has simply concluded that it failed to "identify any negative impacts on aquatic vegetation" with commercial or recreational value from the air emissions from Shell's proposed operations.[269] We ask EPA to explain why this conclusion is correct and why additional information and an actual analysis is not required to comply with 40 C.F.R. § 52.21(o).

In particular, we are concerned about the impacts of Shell's proposed emissions on the "planktonic and benthic foodwebs" that support the Chukchi Sea's "faunal biomass" which is

[263] Letter from Richard Albright, EPA to Susan Childs, Shell at 4 (Sept. 4, 2009).
[264] *See, e.g.*, 3d Quarter Data Report May-July 2009 at Table 1 (discussing power outages, tape errors, etc.).
[265] On September 4, 2009, EPA clarified that as of that date "[t]he monitoring stations at Wainwright and Badami currently are not operating a collocated sampler." Letter from Richard Albright, EPA to Susan Childs, Shell at 4 (Sept. 4, 2009). Therefore, it does not appear as though Shell has submitted any adequate $PM_{2.5}$ data. In its monitoring report, ConocoPhilips expresses several concerns with the adequacy of the $PM_{2.5}$ data it is collecting explaining that it conducted two background tests with different results, it made adjustments to its $PM_{2.5}$ data, and that $PM_{2.5}$ background values are higher than PM_{10} values.
[266] EPA Stmt of Basis at 75.
[267] *Compare* Letter from Richard Albright, EPA to Susan Childs, Shell at 4 (Sept. 4, 2009) *with* Letter from Richard Albright, EPA to Susan Childs, Shell (July 31, 2009).
[268] 40 C.F.R. § 52.21(o)(1).
[269] *See* EPA Stmt of Basis at 78.

one of the highest "in the Arctic, as well as in the world ocean."[270] A full analysis of the impacts from Shell's emissions on the foodwebs in the Chukchi is necessary before Shell can obtain a permit under the CAA.

C. Shell's PSD Permit Must Account for Shut Downs and Start Ups in Light of Mitigation Measures that Will be Necessary to Protect Marine Mammals.

Shell states in its permit application that while "[s]ounds from the *Discoverer* have not previously been measured in the Arctic or elsewhere," "mitigation as described for seismic activities including ramp ups, power downs, and shut downs should not be necessary for drilling activities." Shell Chukchi Sea Marine Mammal Monitoring and Mitigation Plan at 3-4.[271] We disagree that the now typical mitigation measures for activities in the Arctic of powering or shutting down when marine mammals are sited and powering up when the marine life has moved on will not be required of Shell for its drilling operations.

Shell is uncertain of the level of noise that will be emitted by the Discoverer. It includes estimates from 1987 from a drill ship and nearby support ship of "134 dB re 1 μPa at 0.2 km" and another estimate of icebreaker noise of "175 dB re 1 μPa (rms) and 181 dB re 1 μPa (rms), for drilling and icebreaking, respectively" which Shell reduced by "15dB."[272] Putting the need for measurements from the Discoverer aside, the numbers Shell has provided indicate that ramp downs or shut downs may be required to mitigate impacts to marine mammals from its operations. Thus, we ask that EPA ensure that ramp downs and ramp ups, and shut downs and start ups be taken into account in determining the emissions from Shell's operations, as well as the necessary best available control technologies.

D. Shell Has Inconsistently Represented the Engines to Which it is Applying BACT.

In its Exploration Plan for the Chukchi Sea, Shell states repeatedly that:

> (1) "Primary generators on the *Discoverer* retrofitted with selective catalytic reduction devices to reduce NOx emissions to under 0.5 g/kW-hr, and catalytic oxidation devices to reduce CO by 80 percent, VOCs by 70 percent, and PM10 by at least 50 percent,"

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[270] *See* Grebmeier J. and K.H. Dunton, Benthic Processes in the Northern Bering/Chukchi Seas: Status and Global Change in MMC, IMPACTS OF CHANGES IN SEA ICE AND OTHER ENVIRONMENTAL PARAMETERS IN THE ARCTIC Final Workshop Report (2000) (available at: http://mmc.gov/reports/workshop/pdf/seaicereport.pdf#page=82) (Appendix VI).
[271] We also point out that Shell notes elsewhere in its application that "[t]he presence of MMOs onboard drilling and support vessels will be a core component of compliance with the 4MP. The MMOs will be responsible for collecting basic data on observations of marine mammals and for implementing mitigation measures including vessel avoidance measures and factored into *decisions concerning operational shutdown*." Shell Revised OCS App. at 145 (emphasis added).
[272] Shell Chukchi Sea Marine Mammal Monitoring and Mitigation Plan at 3-4.

and

> (2) "All other engines on *Discoverer* will either be Tier 3 (low emissions) or will be retrofitted with catalytic Diesel Particulate Filters to reduce devices to reduce CO, VOCs, and HAPs by at least 80 percent and fine particulate matter by at least 85 percent."[273]

However, as evidenced by Appendix A to this comment letter, this is not the case. Shell is not applying any control technology to the boilers or incinerator beyond "good control technologies." Therefore, these statements are incorrect and mis-leading. Moreover, Shell's assertions does not clearly state that a whole host of engines associated with its operations are not being regulated at all, because Shell has not conducted a BACT analysis for its ancillary vessels or the Discoverer's propulsion engine.

[273] Shell 2010 Exploration Plan at 157-58.