*** ANNOUNCEMENT ***

FINAL DECISION TO ISSUE AN OCS/PSD PERMIT
TO SHELL OFFSHORE INC. FOR
EXPLORATORY DRILLING OPERATIONS IN THE BEAUFORT SEA

On February 17, 2010, the Region 10 office of the United States Environmental Protection Agency (EPA) requested public comment on a proposal to issue an Outer Continental Shelf (OCS)/Prevention of Significant Deterioration (PSD) permit to Shell Offshore, Inc. (Shell). The proposed permit would authorize Shell to conduct a multi-year exploratory oil and gas drilling program with the Frontier Discoverer drillship and support fleet on Shell's current leases in Lease Sales 195 and 202 on the Beaufort Sea OCS, within and beyond 25 miles of the State of Alaska's seaward boundary.

During the public comment period on the proposed permit, which ended on March 22, 2010, EPA received numerous written and oral comments regarding the project. EPA has carefully reviewed each of the comments submitted and, after consideration of the expressed view of all interested persons, the pertinent federal statues and regulations, and additional material relevant to the application and contained in the administrative record, EPA has made a decision in accordance with 40 CFR 52.21 and 40 CFR Part 55 to issue a final OCS/PSD permit to Shell.

The application, final permit, EPA's responses to the public comments, and additional supporting information are available online at:
http://yosemite.epa.gov/R10/airpage.nsf/Permits/beaufortap/

Copies of the final permit and EPA's responses to the comments are also available upon request in writing, or by fax to:

U.S. Environmental Protection Agency
Office of Air, Waste and Toxics (AWT-107)
Attn: Janis Hastings
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

Fax: 206-553-2955

Copies of the final permit and EPA's responses to the public comments are also available for inspection during normal business hours at the locations on the attached list.

Any person who filed comments on the proposed permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) by May 12, 2010 to review any condition of the final permit. Others may petition for review only to the extent of the changes from the proposed to final permit. The petition must include a statement of the reasons for requesting review by the EAB including a demonstration that any issues being raised were raised during the public comment period (including any public hearing) and, when appropriate, a showing that the conditions in question are based on 1) a finding of fact or conclusion of law which is erroneous, or 2) an exercise of discretion or an important policy consideration which the EAB should, in its discretion, review. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only to the extent of the changes from the proposed permit to the final permit decision. The petitions must be received at the EAB no later than May 12, 2010.

The address for the EAB depends on the method of delivery, as follows:

Method of Delivery	
All documents that are sent through the U.S. Postal Service (except by Express Mail)	Documents that are hand-carried in person, delivered via courier, mailed by Express Mail, or delivered by a non-U.S. Postal Service carrier (e.g., Federal Express or UPS)
Address for Petitions	
U.S. Environmental Protection Agency Clerk of the Board, Environmental Appeals Board (MC 1103B) Ariel Rios Building 1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460-0001	U.S. Environmental Protection Agency Clerk of the Board, Environmental Appeals Board Colorado Building 1341 G Street, N.W., Suite 600 Washington, D.C. 20005

IMPORTANT NOTE: Documents that are sent to the EAB's hand-delivery address through the U.S. Postal Service (except by Express Mail) will be returned to the sender and shall not be considered as filed.

Please see 40 CFR 124.19 and visit http://www.epa.gov/eab/ for more information regarding the procedure for appeals to the EAB, including instructions for electronic filing.

Please bring this announcement to the attention of all persons who you know would be interested in this matter.

*** END OF ANNOUNCEMENT ***

Issued April 9, 2010

Copies of the final permit and EPA's responses to the public comments have been sent to the following locations for inspection by the public during normal business hours. If you wish to view the documents at any of these locations, EPA recommends that you first contact the appropriate organization in advance to check the business hours and make any necessary arrangements.

Address:	Kaktovik City Office, 2051 Barter Avenue, Kaktovik, Alaska
Telephone:	907-640-6313
Address	Nuiqsut City Office, 2230 2nd Avenue, Nuiqsut, Alaska
Telephone:	907-480-6727
Address:	Barrow City Office, 2022 Ahkovak Street, Barrow, Alaska
Telephone:	907-852-4050
Address:	EPA Alaska Office, Federal Building, 222 West 7th Ave., #19 Anchorage, Alaska
Telephone:	907-271-5083

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
SEATTLE, WASHINGTON

STATEMENT OF BASIS
FOR PROPOSED
OUTER CONTINENTAL SHELF
PREVENTION OF SIGNIFICANT DETERIORATION
PERMIT NO. R10OCS/PSD-AK-2010-01

SHELL OFFSHORE INC.
FRONTIER DISCOVERER DRILLSHIP
BEAUFORT SEA EXPLORATION DRILLING PROGRAM

Date of Proposed Permit: February 17, 2010

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ABBREVIATIONS AND ACRONYMS

AAC .... Alaska Administrative Code
AC .... Air Cooling
ACMR .... Alaska Costal Management Program
AQCR .... Air Quality Control Regions
ASTM .... American Society of Testing and Materials
BACT .... Best Available Control Technology
CAA .... Clean Air Act
CCTS .... Clean Cam technology Systems
CCV .... Closed Crankcase Ventilation
CDPF .... Catalyzed Diesel Particulate Filter
C.F.R. .... Code of Federal Regulations
COA .... Corresponding Onshore Area
CTM .... Conditional Test Method
Discoverer .... Frontier Discoverer Drillship
DPF .... Diesel Particulate Filter
EGR .... Exhaust Gas recirculation
EO .... Executive Order
EPA .... United States Environmental Protection Agency
EPS .... Electrostatic Precipitator
ESA .... Endangered Species Act
FR .... Federal Register
FTIR .... Fourier Transform Infrared
HAP .... Hazardous Air Pollutants
HC SCR .... Hydrocarbon Selective Catalytic Reduction
HIO .... High Injection Pressure
HPU .... Hydraulic Power Unit
IC .... Internal Combustion
ICAS .... Inupiat Community of the Arctic Slope
ITR .... Injection Timing Retard
LNB .... Low NO_X Burners
LNC .... Low NO_X Catalyst
LND .... Low NO_X Design
LSF .... Low Sulfur Diesel
MLC .... Mud Line Cellar
MMS .... Minerals Management Service
MSA .... Magnuson-Stevens Fishery Conservation and Management Act
NA .... Not applicable
NAAQS .... National Ambient Air Quality Standards
NEPA .... National Environmental Policy Act
NESHAP .... National Emission Standards for Hazardous Air Pollutants
NHPA .... National Historic Preservation Act
NMFS .... National Oceanic and Atmospheric Administration National Marine Fisheries Service
NOAA .... National Oceanic and Atmospheric Administration

NSPS .... New Source Performance Standards
OCS .... Outer Continental Shelf
OCSLA .... Outer Continental Shelf Lands Act
OSR .... Oil spill response
OTM .... Other Test Method
OxyCat .... Oxidation Catalyst
Part 55....................... 40 C.F.R. Part 55
PDF .... Portable Document Format
PERP .... Portable Engine Restoration Program
PSD .... Prevention of Significant Deterioration
PTE .... Potential to Emit
QA/QC .... Quality Assurance/Quality Control
SCAC .... Separate Circuit Aftercooled
SNCR .... Selective Non-Catalytic Reduction
SCR .... Selective Catalytic Reduction
Shell .... Shell Offshore Inc.
SHPO .... State Historic Preservation Act
SIA .... Significant Impact Area
SOF .... Soluble Organic Fraction
SSBOP .... Subsea Blowout Preventer
The Services .... Collectively the National Oceanic and Atmospheric Administration Fisheries and/or the U.S. Fish and Wildlife Service
ULSD .... Ultra-Low Sulfur Diesel
WI .... Water Injection

UNITS AND MEASUREMENTS

Btu............................British thermal units
^oC ....degree Celsius
dscf............................dry standard cubic foot
^oF..............................degree Fahrenheit
g ....grams
hp ....brake horsepower
hr ....hour
km ....kilometers
kW ....kiloWatts (mechanical)
kWe ....kiloWatts electrical
lb ....pounds
MMBtu/hr..................Million British thermal units per hour
ppb ....Parts per billion
ppm ....Parts per million
ppmv ....parts per million by volume
Rpm...........................Revolutions per minute
scf..............................standard cubic foot
tpy ....tons per year
wt percent..................Weight percent

POLLUTANTS

CO.............................Carbon Monoxide
H_2S............................Hydrogen Sulfide
H^2SO_4........................Hydrogen Sulfide Mist
NH_3............................Ammonia
NMHC ....Non-Methane Hydrocarbons
NO_X ....Oxides of Nitrogen
PM.............................Particulate Matter
$PM_{2.5}$ ....Particulate Matter with an Aerodynamic Diameter less than 2.5 microns
PM_{10} ....Particulate Matter with an Aerodynamic Diameter less than 10 microns
SO_2............................Sulfur Dioxide
VOC ....Volatile Organic Compound

1 INTRODUCTION, PROJECT DESCRIPTION AND PUBLIC PARTICIPATION

1.1 Introduction

Pursuant to Section 328 of the Clean Air Act (CAA), 42 U.S.C. § 7627, the United States Environmental Protection Agency (EPA) promulgated air quality regulations applicable to Outer Continental Shelf (OCS) sources, which regulations are set forth in Title 40, Code of Federal Regulations (C.F.R.), Part 55. Under these regulations, an OCS source that is a major stationary source and which proposes to locate on the OCS is required to obtain a Prevention of Significant Deterioration (PSD) permit before beginning construction. The requirements of the PSD program were established under Part C of Title I of the CAA, 42 U.S.C. § 7470-7492, and are found at 40 C.F.R. § 52.21.

Under these programs, Shell Offshore Inc. (Shell) has applied for a major source permit to authorize mobilization and operation of the Frontier Discoverer drillship (Discoverer) and its Associated Fleet at various drill sites in the Beaufort Sea outer continental shelf (OCS) off the North Slope of Alaska in connection with an exploratory oil and gas drilling program (exploration drilling program). The proposed permit will allow Shell to operate the Frontier Discoverer drillship and Associated Fleet for a multi-year exploration drilling program within Shell's current lease blocks in lease sales 195 (March 2005) and 202 (April 2007) on the Beaufort Sea OCS, within and beyond 25 miles from Alaska's seaward boundary. Because the drillship operations would be a "major" source of air pollutants, the permit requires that the operations meet PSD program requirements.

As discussed in Section 2.5.4, the overall emissions of all PSD pollutants allowed from the Discoverer and Associated Fleet at all locations are listed in Table 1-1.

As shown in Table 1-1, the Shell Beaufort Sea Exploration Drilling Program is subject to PSD review under 40 C.F.R. § 55.21 and 18 AAC 50.306 for NO_X, PM, $PM_{2.5}$, PM_{10}, VOC, and CO

Table 1-1: Permitted Air Pollutant Emissions from Discoverer and Associated Fleet as OCS Source at all Locations

Air Pollutant	Emissions (tpy)
Carbon Monoxide (CO)	464
Nitrogen Oxides (NO_x)	1371
Particulate Matter	81
Particulate Matter Less than 2.5 ($PM_{2.5}$)	57
Particulate Matter Less than 10 (PM_{10})	65
Sulfur Dioxide (SO_2)	2
Volatile Organic Compounds (VOC)	96

The permit proposes two alternatives for when the Discoverer is considered an "OCS source" under the permit and when the emission limitations and other operating restrictions apply. In this proposal, EPA seeks comment on considering the Discoverer to be an OCS source when it is

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attached by a single anchor to the seabed. EPA is also soliciting comment on an alternative proposal to consider the Discoverer to be an OCS source when it is sufficiently secure and stable to commence exploratory activity at a drill site.

1.2 Air Pollution Controls

The permit requires Best Available Control Technology (BACT) on the Discoverer and controls on some other emission units including:

- Use of ultra-low sulfur diesel (ULSD) fuel in the Discoverer and Associated Fleet vessels when a vessel is within 25 miles of the Discoverer and the Discoverer is operating as an OCS source.
- Selective catalytic reduction controls on the six largest engines on the Discoverer and the icebreaker/anchor handler's main diesel engines to reduce emissions of NO_X.
- Oxidation catalysts or catalytic diesel particulate filters on the six largest engines and all other engines on the Discoverer to limit emissions of VOC, CO, PM, PM_{10} and $PM_{2.5}$.
- Good operation and maintenance procedures and good combustion practices on the Discoverer and the Associated Fleet.
- Record-keeping and reporting necessary to monitor compliance with permit terms and conditions.

Table 1-2: Application Chronology[1]

January 2010

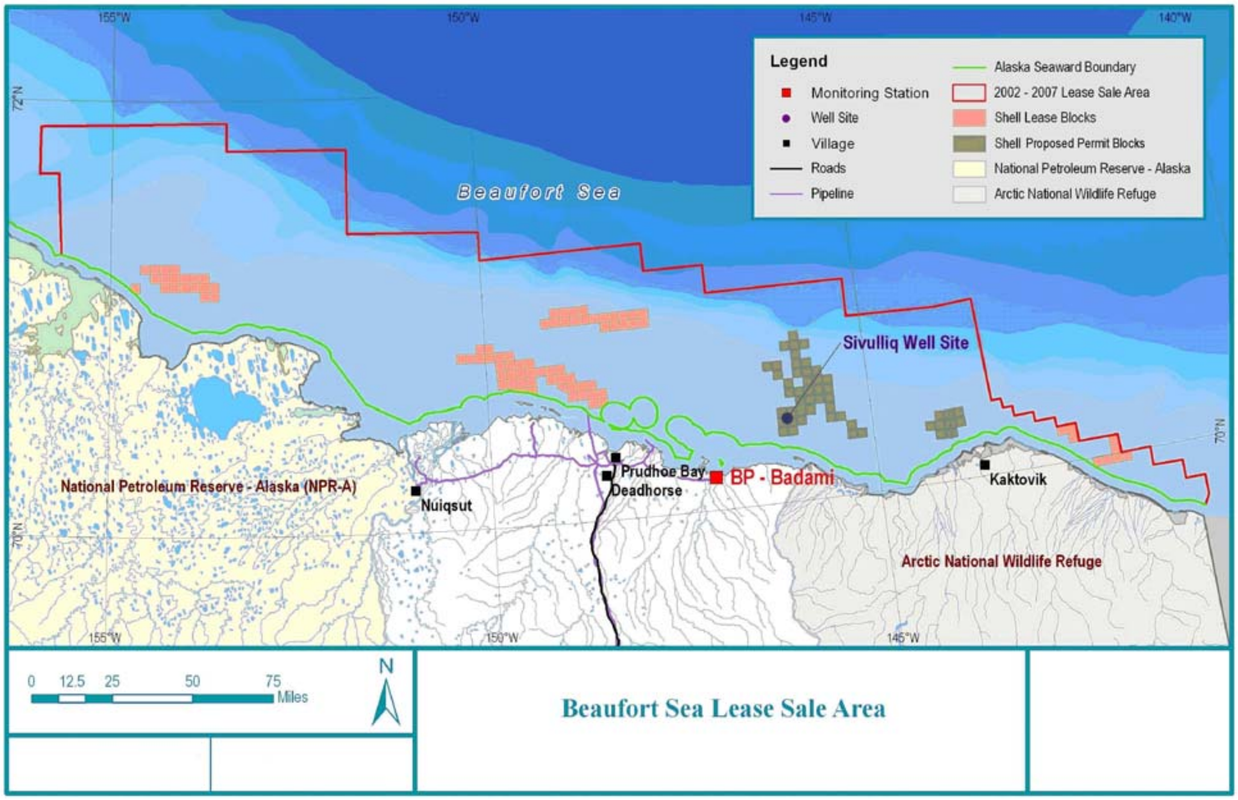
Date	Document Description
01/18/2010	Shell Offshore Inc Outer Continental Shelf Pre-construction Air Permit Application – Frontier Discoverer Beaufort Sea Exploration Drilling Program
01/20/2010	Environ International Corporation Email transmitting a revised Appendix A Emission Inventory

1.3 Project Description

To implement their Beaufort Sea exploration drilling program, Shell proposes to operate the Discoverer drillship and Associated Fleet in the Beaufort Sea. The application submitted by Shell is for a major source permit to allow for operation of the Discoverer and its Associated Fleet at any of Shell Offshore Inc.'s current leases from lease sales 195 (March 2005) and 202 (April 2007) within the Beaufort Sea. The leases from lease sales 195 and 202 are within 25 miles of Alaska's seaward boundary and beyond 25 miles of Alaska's seaward boundary. Figure 1-1 shows the location of the current Shell Offshore Inc. leases in the Beaufort Sea. This region can be described as lying north of Point Thompson near Camden Bay in the Beaufort Sea (latitude 70.1º N to 70.8º N and longitude 143.7º W and 146.4º W).

[1] The Administrative Record also contains numerous emails and correspondence between Shell and its consultants and EPA clarifying various aspects of Shell's application.

Figure 1-1: Beaufort Sea Lease Area Lease Sales 195 and 202



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Under the terms of this proposed permit, the Shell is limited to operating the Discoverer in only the following lease blocks from lease sales 195 and 202:

BF 202:	6259	6308	6309	6310	6359	6406	6407	6409	6410	6457	6459	6460
	6461	6508	6510	6511	6512	6558	6559	6560	6561	6562	6609	6610
	6611	6612	6660	6662								
BF 195:	6657	6658	6659	6707	6708	6709	6712	6713	6751	6752	6757	6758
	6764	6773	6774	6801	6802	6814	6815	6822	6823	6824	6851	6873
	6875											

The Discoverer is a turret-moored drillship that was originally converted for drilling in 1975. It underwent significant upgrades in 2007 so that it could operate in the Arctic. The Discoverer is equipped with generators for the drilling systems and associated self-powered equipment (such as air compressors, hydraulic pumps, cranes, boilers and other small sources), thrusters for positioning, and an emergency generator for the critical non-drilling loads when the main power supply is not operating. These emission units are identified in Table 3-1 and discussed in greater detail in Section 3 of this Statement of Basis. A photograph of the Discoverer is provided in Figure 1-2.

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Figure 1-2: Photograph of the Frontier Discoverer Drillship

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The Discoverer's operations are supported by an Associated Fleet that consists of an icebreaker, an anchor handler/icebreaker, a supply ship, two main oil spill response ships, tugs, barges, two workboats and one skimmer (such support vessels to be referred to hereafter as the "Associated Fleet"). Prior to mobilizing to the Beaufort Sea, the drillship is provisioned with sufficient supplies required to conduct the initial drilling operations. Together with the ice breakers, the Discoverer mobilizes to the desired location. Alternate locations are available in the event that ice conditions at the desired location exceed the fleet's capability to manage ice or conduct operations. Anchors are run and set by the ice breaker/anchor handler vessel; the mooring lines are tensioned; and the Discoverer is thus positioned over the drill site.

Upon completion of the mooring operation, the process to drill the mud line cellars (MLC) is initiated. The MLC is a 20 feet diameter hole excavated to approximately 35 feet below the mud line. The MLC permits installation of the Discoverer's subsea blowout preventers (SSBOP) below the mud line to avoid damage by ice keels should ice floes force the Discoverer off the well. Utilizing compressed air, the excavated seabed material is lifted out of the MLC and settles to the surrounding seafloor. The MLC operation is estimated to take about six days per drill site. A 36 inch diameter hole is drilled for the next well interval and a 30 inch diameter tube (casing) is installed and cemented. Cementing the casing anchors it in the hole and prevents annular formation fluid migration between formations or to the surface. Atop the 30 inch casing is a guide base with receptacles for guidelines that facilitate reentry into the well. The operations are also supported by a cutting/mud disposal barge and tug.

After drilling and installing casing in the next interval, the SSBOP's are installed in the MLC. At this point the oil spill response fleet generally must be in position and be prepared to deploy in the unlikely event of an oil spill. Additional intervals are drilled, cased, and cemented as required to reach and evaluate the geologic objective.

Upon completion of the evaluation operations, the well is properly secured or plugged and then abandoned using mechanical and/or cement plugs, or temporarily abandoned, which generally occurs upon completion of any of the interim operations of cementing the casing. After the well is abandoned the SSBOP's are retrieved. The anchors can then be retrieved and the Discoverer can depart the drill site. The Discoverer may leave a drill site for a variety of reasons, including plugging and abandoning, temporarily abandoning, adverse ice conditions, end of the drilling season, or desire to move to another drill site to start or finish a well that was previously temporarily abandoned.

The Discoverer crew works 12-hour shifts and lives on the drillship in accommodations located at the stern of the ship. They work for three to four weeks and are transported to and from the Discoverer by helicopter to Deadhorse or Barrow, Alaska.

The icebreakers' role is to protect the Discoverer from ice movement. As most of the ice movement is influenced by the wind, the icebreakers will generally be deployed upwind of the drillship. The primary icebreaker will be located further from the Discoverer and cover a wider operating range. The secondary anchor handler/icebreaker will operate closer in and will also serve to deploy and retrieve the Discoverer's anchors.

The Beaufort exploration program will be replenished by a supply ship, or a tug and barge, that is expected to make no more than 8 trips each drilling season from port to the Discoverer. The Discoverer's operations are also supported by two main oil spill response ships, a tug, two workboats and one skimmer which will be deployed in the event of a spill. In preparation for a potential spill, the oil spill response (OSR) fleet will conduct frequent drills.

Shell anticipates a drilling season maximum of 168 drilling days (5.5 months), beginning in July of each year. During each season, it will have the flexibility of drilling one or more wells or parts of wells. It is likely that the environmental conditions (ice) will limit the drilling season to less than these durations. Drilling is planned to begin no earlier than July of 2010 and continue seasonally (i.e. July through December each year) until the resources under Shell's current leases are adequately defined.

1.4 Public Participation

1.4.1 Opportunity for Public Comment

40 C.F.R. Part 124, Subparts A and C, contain the procedures that govern the issuance of both OCS and PSD permits. See 40 C.F.R. §§ 55.6(a) (3) and 124.1. Accordingly, EPA has followed the procedures of 40 C.F.R. Part 124 in issuing this proposed permit. This Statement of Basis describes the derivation of the permit conditions and the reasons for them as provided in 40 C.F.R. § 124.7. It also serves as a Fact Sheet as provided in 40 C.F.R. § 124.8.

As provided in Part 124, EPA is seeking public comment on the proposed Shell OCS/PSD permit for the Beaufort Sea. The public comment period runs from February 17, 2010 through March

22, 2010. All written comments must be postmarked by March 22, 2010. As discussed in Section 5 of this Statement of Basis, EPA is also soliciting public comment on the use of the non-guideline ISC3-PRIME modeling system to predict air pollutant concentrations in connection with issuance of this proposed permit.

If you believe any condition of this permit is inappropriate, you must comment on the permit and raise all reasonably ascertainable issues and submit all reasonably ascertainable arguments supporting your position by the end of the comment period. Any documents supporting your comments must be included in full and may not be incorporated by reference unless they are already part of the record for this permit or consist of state or federal statutes or regulations, EPA documents of general applicability, or other generally available referenced materials.

Written comments may be submitted by mail or email. Oral comments may be submitted during the public hearing in Barrow, Nuiqsut, and Kaktovik. Oral comments may also be recorded on cassette tape or CD, and submitted by mail. EPA recommends that all comments, including those submitted by email, cassette tape, or CD, include the commenter's contact information so that we may provide all commenters with notice of the final permit decision. If EPA cannot read a comment due to technical difficulties and cannot contact the commenter for clarification, EPA may not be able to consider the comment. Please be aware that any personal information, including addresses or phone numbers that are included with a public comment will be included in the public record for the proposed permit.

Send comments on the proposed permit to:

Email: R10ocsairpermits@epa.gov
Fax: 206-553-0110
Mail: Shell Beaufort Air Permit
EPA Region 10
1200 6th Ave, Ste. 900, AWT-107
Seattle, WA 98101

All timely comments will be considered in making the final decision, included in the record, and responded to by EPA. EPA will prepare a statement of reasons for changes made in the final permit and a response to comments received, and will provide all commenters with notice of the final permit decision.

1.4.2 Public Hearing and Informational Meetings

EPA is holding a public hearing on the proposed OCS/PSD permit as follows:

March 16, 2010 Information Meeting: 6:00 pm Public Hearing: 7:00 pm City Office Kaktovik, Alaska	March 17, 2010 Information Meeting: 6:00 pm Public Hearing: 7:00 pm City Office Nuiqsut, Alaska	March 18, 2010 Information Meeting: 6:00 pm Public Hearing: 7:00 pm City Office Barrow, Alaska

The purpose of the public hearing is to receive public comments on EPA's proposed OCS/PSD air quality permit for Shell to operate the Frontier Discoverer drillship on the Beaufort Sea OCS. To express interest in attending the public hearing or for more information about the hearing,

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contact Suzanne Skadowski, EPA community involvement, at 206-553-6689 or skadowski.suzanne@epa.gov.

Inupiat translation will be available at the meeting and hearing in Nuiqsut and Kaktovik based on consultation with the North Slope Borough.

A commenter may submit oral or written comments on the proposed permit at the public hearings. It is not necessary to attend the public hearings in order to submit written comments. For more information about these meetings, contact Suzanne Skadowski, EPA Region 10, Seattle, Washington, 206-553-6689 or 800-424-4372 or skadowski.suzanne@epa.gov.

1.4.3 Administrative Record

The record for the proposed permit includes Shell's application and supplemental information; statement of basis; and all other materials relied on by EPA.

The permit record for the proposed permit is available at the EPA Region 10 Library, 1200 6th Ave, Seattle, Washington. Library hours: 9:00 am–12:00 pm and 1:00 pm–4:00 pm Monday-Friday. To request a copy of these materials or a copy of the permit record, contact Suzanne Skadowski as described above.

The permit application, the proposed permit and statement of basis will also be available at the locations listed below. Please call in advance for available viewing times.

Barrow City Office, 2022 Ahkovak Street, Barrow, Alaska, 99723, (907) 852-4050
Kaktovik City Office, 2051 Barter Avenue, Kaktovik, Alaska, 99747, (907) 640-6313
Nuiqsut City Office, 2230 2nd Street, Nuiqsut,, Alaska, 99789, (907) 480-6727
EPA Alaska Office, Federal Building, 222 West 7th Ave, Anchorage, Alaska, (907) 271-5083
EPA Region 10 web site: www.yosemite.epa.gov/R10/airpage.nsf/Permits/Beaufortap

For more information about the public hearing or the proposed permit, to request a copy of the permit documents on CD, or to be added to EPA's arctic permits mailing list, contact Suzanne Skadowski at 206-553-6689 or skadowski.suzanne@epa.gov.

2 REGULATORY APPLICABILITY

2.1 The Outer Continental Shelf

The OCS regulations at 40 C.F.R. Part 55 (Part 55) implement Section 328 of the CAA and establish the air pollution control requirements for OCS sources and the procedures for implementation and enforcement of the requirements. 40 C.F.R Part 55,[2] established requirements to control air pollution from OCS sources in order to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of Part C of Title I of the Act. Part 55 applies to all OCS sources offshore of the States except those located in the Gulf of Mexico west of 87.5 degrees longitude.

The regulations define "OCS source" by incorporating and interpreting the statutory definition of OCS source:

> *OCS source* means any equipment, activity, or facility which:
>
> (1) Emits or 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.

40 C.F.R. § 55.2; see also CAA § 328(a)(4)(C), 42 U.S.C. § 7627(a)(4)(c).

The OCS regulations also contain provisions relating to monitoring, reporting, inspections, compliance, and enforcement. See 40 C.F.R. §§ 55.8 and 55.9. Section 55.8(a) and (b) authorize EPA to require monitoring, reporting, and inspections for OCS sources and provide that all monitoring, reporting, inspection, and compliance requirements of the CAA apply to OCS sources. These provisions, along with the provisions of the applicable substantive programs, provide authority for the monitoring, recordkeeping reporting and other compliance assurance measures included in this proposed permit.

Section 328 and Part 55 distinguish between OCS sources located within 25 miles of a state's seaward boundaries referred to in this Statement of Basis as "the Inner OCS" and those located beyond 25 miles of a state's seaward boundaries, referred to in this Statement of Basis as "the Outer OCS". CAA § 328(a)(1); 40 C.F.R. §§ 55.3(b) and (c). In this case, Shell is seeking a

[2] The reader may refer to the Notice of Proposed Rulemaking, December 5, 1991 (56 FR 63774), and the preamble to the final rule promulgated September 4, 1992 (57 FR 40792) for further background and information on the OCS regulations.

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permit for an exploration drilling program that will be conducted beyond 25 miles of Alaska's seaward boundary and within 25 miles of Alaska's seaward boundary.

Beyond 25 miles of Alaska's Seaward Boundary (Outer OCS)

Section 55.13 generally sets forth the federal requirements that apply to OCS sources. Sources located beyond 25 miles of a state's seaward boundaries are subject to the New Source Performance Standards (NSPS), in 40 C.F.R Part 60; the PSD program in 40 C.F.R. § 52.21 if the OCS source is also a major stationary source or a major modification to a major stationary source; 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; and the operating permit program under Title V of the CAA and 40 C.F.R. Part 71. See 40 C.F.R. §§ 55.13(a), (c), (d)(2), (e), and (f)(2), respectively. The applicability of these requirements to Shell's exploration drilling program is discussed in Sections 2.2 to 2.9 below.

Within 25 miles of Alaska's Seaward Boundary (Inner OCS)

Section 328 of the CAA provides that the requirements for sources located within 25 miles of a State's seaward boundary be the same as would be applicable if the sources were located in the corresponding onshore area (COA)[3]. Because the OCS requirements are based on onshore requirements, and onshore requirements may change, Section 328(a)(1) requires that EPA update the OCS requirements as necessary to maintain consistency with onshore requirements.

On March 3, 2009, (74 FR 1980), EPA proposed to approve requirements into the OCS Air Regulations pertaining to the State of Alaska. These requirements were promulgated in response to the submittal of a Notice of Intent on January 9, 2009, by Shell. On January 21, 2010, (75 FR 3387) EPA finalized the consistency update. EPA also took direct final action (75 FR 3392) to include the revised applicability dates in the emission user fees provision in 18 AAC 50.410. EPA incorporated applicable provisions of the following Alaska Administrative Code (AAC) regulations by reference into 40 C.F.R. § 55.14:

- Article 1 – Ambient Air Quality Management;
- Article 2 – Program Administration;
- Article 3 – Major Stationary Source Permits;
- Article 4 – User Fees;
- Article 5 – Minor Permits; and
- Article 9 – General Provisions.

This major source permit authorizes the mobilization and operation of the Discoverer drillship and its Associated Fleet at various drill sites in the Beaufort Sea OCS off the North Slope of Alaska in connection with an exploratory oil and gas drilling program (exploration drilling program). The proposed permit will allow Shell to operate the Frontier Discoverer drillship and

[3] Defined in 40 C.F.R. § 55.2 "Corresponding Onshore Area (COA) means, with respect to any exosting or proposed OCS source located within 25 miles of a State's seaward boundary, the onshore area that is geographically closest to the source or another onshore area that the Administrator designates as the COA pursuant to § 55.5 of this part."

Associated Fleet for a multi-year exploration drilling program within Shell's current lease blocks in lease sales 195 and 202 on the Beaufort Sea OCS (Figure 1-1). The group of lease blocks authorized under this permit is located within 25 miles and beyond 25 miles of Alaska's seaward boundary. In some instances, lease blocks are both within and beyond 25 miles from Alaska's seaward boundary.

The leases can be divided into the three following groups:

- Lease blocks entirely outside 25 miles of Alaska's seaward boundary (Outer OCS) – 6529, 6308, 6309, 6310, 6359, and 6410
- Lease blocks with portions both inside and outside 25 miles of Alaska's seaward boundary (both Outer and Inner OCS)– 6406, 6407, 6409, 6459, 6460, 6461, and 6512
- Lease blocks entirely within 25 miles of Alaska's seaward boundary (Inner OCS) – 6457, 6508, 6510, 6511, 6558, 6559, 6560, 6561, 6562, 6609, 6610, 6611, 6612, 6657, 6658, 6659, 6660, 6662, 6707, 6708, 6709, 6712, 6713, 6757, 6758, 6764, 6814, 6815, 6773, 6774, 6751, 6752, 6822, 6823, 6824, 6801, 6802, 6873, 6874, and 6851.

Figure 2-1 is a close up of lease blocks, delineating which lease blocks are located in the Inner OCS and which are in the Outer OCS.

Figure 2-1: Close Up view of Lease Blocks Addressed in the Beaufort Sea

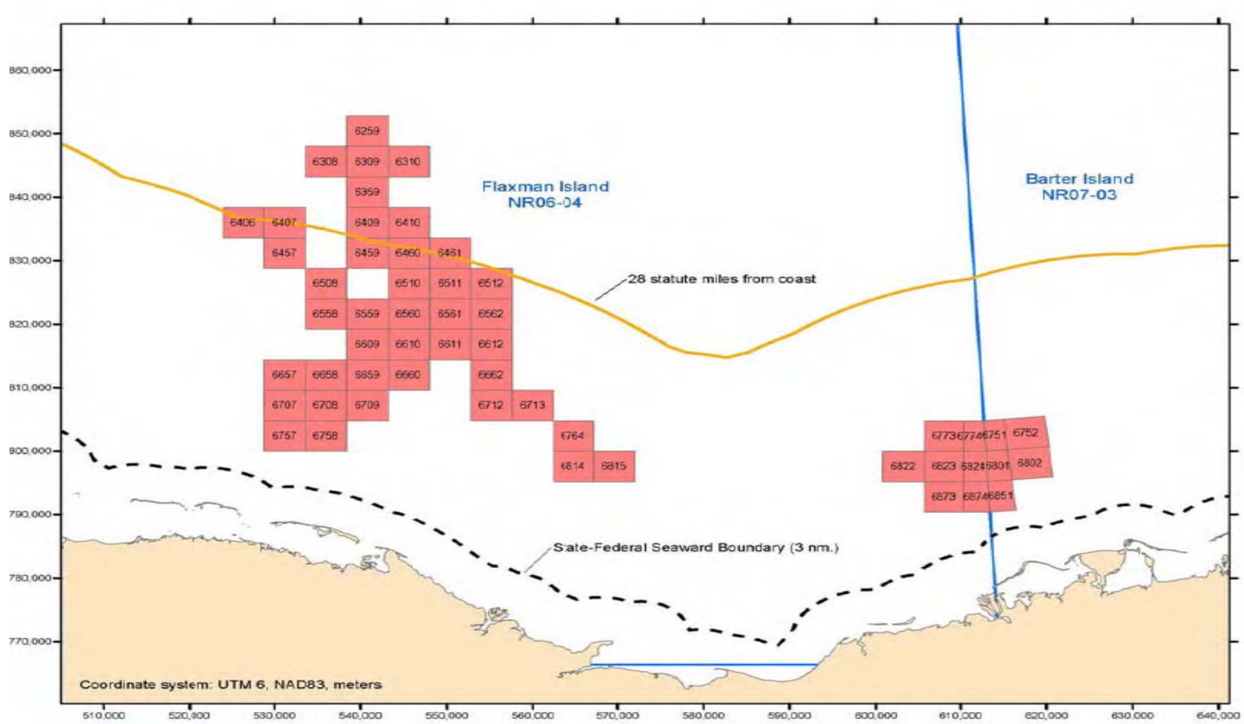

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Exhibit 5
AEWC & ICAS

2.2 Prevention of Significant Deterioration

The PSD program, as set forth at 40 C.F.R. § 52.21, and incorporated by reference into 40 C.F.R. § 55.13(d)(2), applies to the construction of any new major stationary source or the major modification of an existing major stationary source in an area that has been designated as in attainment of the national ambient air quality standards (NAAQS) or as "unclassifiable."[4] The objective of the PSD program is to prevent significant adverse environmental impact from air emissions by a proposed new or modified source. The PSD program limits degradation of air quality to that which is not considered "significant." In addition, the PSD program includes a requirement for evaluating the effect that the proposed emissions are expected to have on air quality related values such as visibility, soils, and vegetation. The PSD program also requires the utilization of the best available control technology (BACT) as determined on a on a case-by-case basis taking into account energy, environmental and economic impacts and other costs.

Under the PSD regulations, a stationary source is "major" if, among other things, it emits or has the potential to emit (PTE) 100 tons per year (tpy)or more of a "regulated NSR pollutant" as defined in 40 C.F.R. § 52.21(b)(50) and the stationary source is one of a named list of source categories. In addition to the preceding criteria, any stationary source is also considered a major stationary source if it emits or has the PTE 250 tpy or more of a regulated NSR pollutant. 40 C.F.R. § 52.21(b)(1). PTE is defined as the maximum capacity of a source to emit a pollutant under its physical and operational design. "Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable." See 40 C.F.R. § 52.21(b)(4).

Under the PSD program, a source's PTE is used to determine not only when it is required to obtain a PSD permit, but also to determine the scope of PSD review, in particular, the pollutants that are subject to application of "best available control technology" or "BACT," analysis of ambient air quality impacts from the project, analysis of air quality and visibility impact on Class I areas, and analysis of impacts on soils and vegetation. A source is required to apply BACT for each pollutant for which the PTE exceeds the "significant emission rate" or "SER" within the meaning of 40 C.F.R. § 52.21(b)(23)(i). Additionally, and consistent with 40 C.F.R. § 52.21(k) and (m), Shell is required in its permit application to include an analysis of ambient air quality for each of these pollutants and a demonstration that it will not cause or contribute to a violation of any NAAQS or PSD increment.[5]

2.3 Applicability of the NAAQS and PSD Increments on the OCS

Pursuant to Sections 108 and 109 of the CAA, EPA has promulgated primary and secondary NAAQS to protect public health and the environment. These national standards apply in the

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[4] Section 109 of the CAA requires EPA to promulgate regulations establishing NAAQS for those air pollutants (criteria pollutants) for which air quality criteria have been issued pursuant to Section 108 of the CAA. EPA has set NAAQS for six criteria pollutants: SO_2, particulate matter (PM_{10} and $PM_{2.5}$), nitrogen dioxide (as NO_x), CO, ozone (precursors NO_x and VOC) and lead. 40 C.F.R. Part 50. An area that meets the NAAQS for a particular pollutant is an "attainment" area. An area that does not meet the NAAQS is a "nonattainment" area. An area that can not be classified due to insufficient data is designated "unclassifiable."

[5] PSD increments are the "applicable maximum allowable increase over baseline concentration in any area" and are set forth in 40 C.F.R. § 52.21(c).

Exhibit 5
AEWC & ICAS

"ambient air," which is defined in 40 C.F.R. § 50.1(e) as "…that portion of the atmosphere, external to buildings, to which the general public has access." The atmosphere over United States territorial waters is "ambient air" and United States law, including 40 C.F.R. Part 50 in which the NAAQS are promulgated, applies within the boundaries of United State and its territorial waters. Nothing in the CAA or EPA's implementing regulations limits the applicability of the NAAQS to ambient air over land or to only ambient air within the jurisdiction of states or tribes.

Pursuant to Section 328 of the CAA, EPA has promulgated regulations at 40 C.F.R. Part 55 to control air pollution from OCS sources in order to attain and maintain federal and state ambient air quality standards and to comply with the provisions of Part C of Title I to prevent significant deterioration of air quality. With respect to PSD, 40 C.F.R. § 55.13(d) states that the PSD rules at 40 C.F.R. § 52.21 shall apply to OCS sources. The PSD rules specifically include, at 40 C.F.R. § 52.21(c), the ambient air increments, and at 40 C.F.R. § 52.21(d), the ambient air ceilings (NAAQS), that must be addressed in the source impact analysis required by 40 C.F.R. § 52.21(k). Further technical information on implementing the PSD increments on the OCS, specifically, the definitions of "baseline concentration," baseline date," and "baseline area," is contained in the EPA 07/02/09 Baseline Memo.

As discussed above, Section 328 of the CAA requires EPA to promulgate regulations to control air pollution from OCS sources in order to attain and maintain federal and state ambient air quality standards and to comply with the provisions of Part C of Title I to prevent significant deterioration of air quality. While Congress evinced an intent that EPA's regulations ensure protection of air quality onshore, EPA does not interpret Section 328 of the CAA to address only the air quality impacts of offshore sources on onshore areas. Section 328 does not identify a particular area where the requirements to control air pollution from OCS source located offshore must "attain and maintain Federal and State ambient air quality standards" or limit that area to only locations onshore. Furthermore, the D.C. Circuit of the Court of Appeals vacated certain provisions of EPA's Part 55 OCS rules that would have varied the stringency of onshore ambient-based requirements (e.g., the amount of offsets) based on the distance of the OCS source from shore, even though the rules would have ensured protection of onshore air quality because EPA had departed from the CAA's clear directive that the agency promulgate the same "requirements…as would be applicable if the source were located in the corresponding onshore area." <u>Santa Barbara County Air Pollution Control District v. EPA</u>, 31 F.3d 1179, 1183 (D.C. Cir. 1994) (citing to Section 328(a)(1) of the CAA). The Court concluded that EPA could not change the stringency of the onshore rules as applicable to offshore sources within 25 miles of a state's seaward boundary. Id. Likewise, by making 40 C.F.R. § 52.21 applicable without change to OCS sources located more than 25 miles beyond a state's seaward boundary, see 40 C.F.R. § 55.13(d)(2), EPA expressed an intent that the OCS permitting rules applicable to such sources located more than 25 miles beyond a state's seaward boundary would apply in the same manner as 40 C.F.R. § 52.21 would apply to onshore sources. This includes rules with respect to the ambient air quality provisions, which require NAAQS and increment compliance in the ambient air. By requiring Shell to show that its operations comply with NAAQS and increment in the ambient air of lease sales 195 (March 2005) and 202 (April 2007), this permit ensures that air quality is protected everywhere that the PSD and OCS rules apply, including onshore and offshore areas.

Exhibit 5
AEWC & ICAS

2.4 Applicability of the Corresponding Onshore Area Rules

EPA incorporated by reference, certain provisions of the Alaska regulations found at 18 AAC 50, into 40 C.F.R. Part 55 pursuant to Section 328(a)(1) of the CAA, 42 U.S.C. § 7627. Section 328(a) of the Act requires that EPA establish requirements to control air pollution from OCS sources located within 25 miles of states' seaward boundaries in a manner that is consistent with onshore requirements. To comply with this statutory mandate, EPA incorporates applicable State of Alaska onshore rules into Part 55. See 75 FR 3387 and 75 FR 3392 (January 21, 2010) The Discoverer drillship and its Associated Fleet are subject to several AAC regulations, as adopted into 40 C.F.R. § 55.14[6]:

- The Discoverer incinerator (FD-23) is subject to the visible emission standards in 18 AAC 50.050(a). Emissions from the Discoverer incinerator cannot reduce visibility through the exhaust by more than 20 percent averaged over six consecutive minutes.
- The Discoverer generators, engines and boilers (Units FD 1 through 22) and the supply ship generator (FD-31) are subject to the industrial processes and fuel-burning equipment visible emission, particulate matter, and sulfur-compound emission standards in 18 AAC 50.055. Emissions from the Discoverer generators, engines and boilers can not reduce visibility by more than 20 percent averaged over any six consecutive minutes; particulate matter may not exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions averaged over three hours; and may not emit more than 500 ppm of sulfur dioxide averaged over three hours.
- The Discoverer drillship and its Associated Fleet are subject to the marine visible emission standards in 18 AAC 50.070. Emission units subject to 18 AAC 50.070 may not reduce visibility through the exhaust effluent of marine vessels by more than 20 percent except while at berth or anchor, during the hour immediately after weighing anchor or casting off, or during the hour immediately before the completion of all maneuvers to anchor or make fast to shore.
- Shell has requested an owner requested limit (ORL) for sulfuric acid mist (H_2SO_4) under 18 AAC 50.225. Using fuel with a higher sulfur content (e.g., 0.19%) could result in a PTE that exceeds the significant emission rate for H_2SO_4. Shell has committed to combust only ULSD in all emission units on the Discoverer and Associated Fleet to keep the H_2SO_4 PTE below the significant emission rate.

2.5 Application of OCS and PSD Regulations to the Discoverer's Exploration Drilling Operations

2.5.1 The "OCS Source"

The Discoverer is a turret-moored drillship that is able to move under its own power. During transit, it is propelled by a 7,200 hp Mitsubishi engine. The drill ship uses a Sonat Offshore Drilling turret mooring system that provides the ability for the drill rig floor to remain stationary while the vessel itself may rotate, allowing the vessel bow to be oriented into the wind or broken

[6] References to a particular regulation in the AAC are intended to refer to the versions of the regulations that have been incorporated into Part 55.

ice (See e.g. Shell 2010 OCS Lease Exploration Plan, Camden Bay, pages 5-6 and Attachment A; United States Patent No. 4,509,448). When the Discoverer reaches the approximate location of the drill site, the anchor handler/icebreaker (Icebreaker #2) is used to attach anchor lines from the Discoverer to the seabed. The mooring system uses a set of eight mooring lines, buoys and anchors which are radially located around the drillship. Drilling can occur when the Discoverer is secured with fewer than eight anchors (United States Patent No. 4,509,448).

Anchor setting involves Icebreaker # 2 backing up to the Discoverer under low power, connecting to the anchor line, reeling out the line, and setting the anchor at approximately 1,000 meters distance, then moving to another anchor opposite the first. Setting of each anchor consumes about 30 minutes and the entire anchoring process consumes no more than 18 hours.

Once there are enough mooring lines out to control the position of the vessel with the mooring lines, the vessel is put into position and mooring lines are adjusted to allow operations to be undertaken at a drill site. Once the Discoverer is positioned and the anchor lines re-tensioned at the drill site, the Discoverer's on-site Shell representative declares that the Discoverer is "secure and stable in a position to commence activity at the well location," an event that is recorded in log books on the Discoverer. The propulsion engine is not used when the Discoverer is an OCS source. (Shell Beaufort Permit Application 01/18/10).

When the Discoverer prepares to depart from the drill site, the process is reversed--anchors are de-tensioned and then the anchor lines released. Specifically, Icebreaker #2 moves to the location of an anchor and attaches to the retrieval cable that is marked by a buoy. Icebreaker #2 then tugs on the anchor to release it and raise it, and then ferries it back to the Discoverer as the cable is rewound. Retrieval of each anchor takes about 30 minutes and the entire process generally lasts for no more than18 hours. There is also a process for a partial or quick release from the anchor lines in the event of approaching hazards (Shell Beaufort Permit Application 01/18/10).

EPA has reviewed the definition of OCS source in the CAA and the OCS implementing regulations in light of the specific configuration of the Discoverer and its mooring and drilling system. EPA's definition of "OCS source" provides that a vessel be considered an OCS source "only when [it is]: (1) Permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing or producing resources therefrom...." 40 C.F.R. § 55.2 (emphasis added). The Discoverer could be considered to be "attached to the seabed" when it is connected to the seabed by a single anchor. After attachment of an anchor at the drill site, the Discoverer begins the process of moving onto location at the drill site through the anchoring and tensioning process discussed above. However, it is not clear that the ship is "erected" on the seabed for the purposes of exploring, developing or producing resources at that time. The question is whether the Discoverer is an OCS source during this anchoring and tensioning process.

In light of the regulatory definition of the OCS source, the application of that definition for specific permitted activity EPA is proposing two options for defining when the Discoverer becomes an OCS source in this permit. EPA is specifically requesting comment on which of the following definitions to include in the final permit:[7]

[7] We note that the choice of either definition below does not effect any other permit conditions or analyses.

Option 1: Under this approach, the Discoverer would be considered an "OCS source" within the meaning of 40 C.F.R. § 55.2 from the time between the placement of the first anchor on the seabed to the removal of the last anchor from the seabed at a drill site. Once the Discoverer is attached by an anchor to the seabed at a drill site, the Discoverer is at that location for the purpose of exploring, developing or producing resources from the seabed and its activities are more closely aligned with the activities of a stationary source than of a vessel transiting the sea. Under this approach, connection of the Discoverer to the seabed by an anchor at the drill site would be considered both attachment to and erection on the seabed.

Option 2: Apply the definition so that the Discoverer is considered to be an "OCS source" within the meaning of 40 C.F.R. § 55.2 from the time the Discoverer is declared by the Discoverer's on-site company representative to be "secure and stable in a position to commence exploratory activity at the drill site," an event which is recorded in the Discoverer's logs). At this point, the Discoverer is clearly both attached to and erected on the seabed "for the purpose of exploring, developing or producing resources therefrom" within the meaning of EPA's OCS implementing regulations. EPA does not agree with Shell that the Discoverer is not an OCS source until all eight anchors are attached, since available information shows that the Discoverer is at that location for the purpose of exploring, developing, or producing resources and that there are some circumstances in which the Discoverer can safely drill when secured by fewer than eight anchors. Accordingly, this option for defining when the Discoverer is an OCS source does not turn on the number of anchors in place.

As discussed in Section 2.1 above, a vessel is also considered an OCS source when it is "[p]hysically attached to an OCS facility, in which case only the stationary source aspects of the vessels will be regulated." 40 C.F.R. § 55.2 (definition of OCS source). Shell's application states that the Discoverer will be provisioned with additional supplies by a supply vessel every two to four weeks during the drilling season, for a maximum of eight re-provisioning events each season. When the supply vessel makes a delivery, it will attach to the Discoverer for less than 12 hours, during which time only one of the supply vessel's generators will be operating. During the time the supply vessel is attached to the Discoverer while the Discoverer is an OCS source, the supply vessel will also be considered an OCS source for purposes of this permit.

Aside from the supply vessel, none of the other vessels that comprise the Associated Fleet will be physically attached to the Discoverer while the Discoverer is an OCS source and, therefore, none of these other vessels are considered an OCS source for purposes of this permit.[8] The OCS regulations make clear that, although the emissions from a vessel servicing an OCS source and within 25 miles of the OCS Source are considered as direct emissions from the OCS source for purposes of determining the requirements to which the OCS source is subject and in considering

[8] Even if the Discoverer is considered to be an OCS source when it is connected to the seabed at a drill site by a single anchor, EPA does not consider Icebreaker # 2 to be "physically attached" to the Discoverer (and thus not an "OCS source") during the time it is assisting the Discoverer in the anchor setting and retrieval process at a drill site. Although there is an anchor line running between the Discoverer and Icebreaker # 2 during portions of this period, Icebreaker # 2 can not be considered in any way to be physically attached to the Discoverer during this time within the meaning of "OCS source" as set forth in 40 C.F.R. § 55.2. The activities during anchor handling are not designed to "to fasten, secure or join" Icebreaker # 2 to the Discoverer or "to connect as an adjunct or associated condition or part" Icebreaker # 2 to the Discoverer, the common meaning of "attached" in this context. *The American Heritage Dictionary of the English Language*, 4th ed., (2006). Rather, Icebreaker # 2 is enabling the attachment of the Discoverer to the seabed.

the impact from the OCS source, such a vessel is not regulated as an OCS source itself. 57 FR 40792, 40794 (September 4, 1992).

2.5.2 Vessels included in the "Potential to Emit" of Shell's Exploration Drilling Program

As discussed in Section 2.2, whether a source is required to obtain a PSD permit under 40 C.F.R. § 52.21 depends on the source's "potential to emit" or PTE. In the case of "potential emissions" from an OCS source, Part 55 defines the term similarly to the definition of PTE in the PSD regulations and provides further that:

Pursuant to Section 328 of the Act, emissions from vessels servicing or associated with an OCS source shall be considered direct emissions from such a source while at the source, and while en route to or from the source when within 25 miles of the source, and shall be included in the "potential to emit" for an OCS source. This definition does not alter or affect the use of this term for any other purposes under §§ 55.13 or 55.14 of this part, except that vessel emissions must be included in the "potential to emit" as used in §§ 55.13 or 55.14 of this part.

40 C.F.R. § 55.2 (definition of "potential emissions")

Thus, emissions from vessels servicing or associated with an OCS source that are within 25 miles of the OCS source are considered in determining the "potential to emit" or "potential emissions" of the OCS source for purposes of applying the PSD regulations. Emissions from such associated vessels are therefore counted in determining whether the OCS source is required to obtain a PSD permit, as well as in determining the pollutants for which BACT is required and whether emissions from the OCS source cause or contribute to a violation of the NAAQS or applicable increment. 57 FR 40793-94 ("vessel emissions related to OCS activity will be accounted for by including vessel emissions in the "potential to emit" of an OCS source. Vessel emissions must be included in offset calculations and impact analyses, as required by Section 328 and explained in the NPR."); 56 FR 63774, 63777 (Dec. 5, 1991) ("The inclusion of vessel emissions in the total emissions of the stationary source is a statutory requirement under Section 328(a)(4)(C). In this manner vessel emissions of attainment pollutants will be accounted for when PSD impact analyses are performed and increment consumption is calculated. For nonattainment pollutants the OCS source will have to obtain offsets as required by the Corresponding Onshore Area and vessel emissions will be offset.").

Drill ships and other vessels contain many emission sources that otherwise meet the definition of "nonroad engine" as defined in Section 216(10) of the CAA. However, based on the specific requirements of CAA Section 328, emissions from these otherwise nonroad engines on drill ships and subject support vessels are considered as "potential emissions" from the OCS source, notwithstanding the fact that Section 302(z) of the CAA specifically excludes nonroad engines from the definition of "stationary source." Similarly, nonroad engines that are part of the OCS source are subject to regulation as stationary sources.

Neither the definition of "OCS source" in Section 328 of the CAA nor the definition in 40 C.F.R. § 55.2 expressly excludes or even mentions an exclusion for emissions from nonroad engines, although EPA makes clear that emissions from engines being used for propulsion are not included within the definition of "OSC source" for those vessels that become an OCS source by attaching to an existing OCS facility. See 40 C.F.R. § 55.2, (definition of OCS source). Indeed, in describing the emission sources included in the definition of "OCS source," both the statutory and regulatory definition broadly include "any equipment, activity, or facility which – emits or has the potential to emit any air pollutant…." CAA Section 328(a)(4)(C); 40 C.F.R. § 55.2.

In describing how emissions from vessels that are not themselves an OCS source are to be considered, both the statute and EPA's regulation refer broadly to "vessel" emissions, again without exclusion. In explaining that only the stationary aspects (i.e., excluding engines when being used for propulsion in the situation described above) of a vessel would be regulated as part of the "OCS source," EPA stated in contrast that "All vessel emissions related to OCS source activity will be accounted for by including vessel emissions in the "potential to emit" of an OCS source." 57 FR 40794 (emphasis added). Simply put, the exclusion of nonroad engines from the general definition of "stationary source" in Section 302(z) of the CAA is overridden by the more specific provisions in Section 328 of the CAA and 40 C.F.R. § 55.2.

In determining the PTE for Shell's Beaufort Sea exploration drilling program, EPA included the potential emissions from the Discoverer while operating as an OCS source, as well as the potential emissions from the Associated Fleet – the ice breaker, the anchor handler/icebreaker, the supply ship, and the OSR fleet – when operating within 25 miles of the Discoverer while the Discoverer is an OCS source. These emissions from the Associated Fleet when servicing or within 25 miles of the Discoverer was also included in the PTE calculation to determine assessable emissions for fee purposes. (See Section 3.2 below)

There are other vessels that will be associated with Shell's exploratory drilling program, such as an oil tanker, a barge, and shallow water landing craft. Based on Shell's application submittals, none of these vessels will be operating within 25 miles of the Discoverer while the Discoverer is an OCS source. Emissions from these other vessels are therefore not included in determining the PTE of Shell's exploration drilling program in connection with applying the requirements of the OCS or PSD program.

2.5.3 Owner Requested Limit for Sulfuric Acid Mist

Shell submitted an ORL under 18 AAC 50.225(s), to limit the PTE for H_2SO_4 below the significant emission rate of 7 tpy. The ORL request will avoid applicability of the State of Alaska's PSD rule in 18 AAC 50.306 for emissions of H_2SO_4. Shell has committed to combusting only ULSD (0.0015 weight percent) fuel in all emission units in the Associated Fleet. Using ULSD will result in a PTE for H_2SO_4 of less than 1 tpy. Shell is required to determine the fuel sulfur content in each fuel oil storage tank or upon receiving each fuel sample. The permit terms to ensure compliance with the ORL for the Associated Fleet are contained in Condition B.5.

2.5.4 "Potential to Emit" of the "OCS Source"

Because Shell has applied for a major source permit authorizing operation of the Discoverer and its Associated Fleet at any of Shell's current leases in lease sales 195 (March 2005) and 202 (April 2007) of the Beaufort Sea, the PTE from the project is calculated based on emissions from any point within the area of operation authorized under the permit during any consecutive 12-month period.

Table 2.1 lists the final PTE for each regulated NSR pollutant from the project, as well as the significant emission rate for each regulated NSR pollutant. Appendix A contains detailed emissions calculations used to determine PTE for emissions of CO, NO_X, $PM_{2.5}$, PM_{10}, SO_2, VOC and lead, the regulated NSR pollutants that are NAAQS pollutants or precursors to

NAAQS pollutants and are therefore relevant to the ambient air quality impact analysis discussed in Section 5 of the Statement of Basis. The PTE estimates for the remaining regulated NSR pollutants are set forth in Shell's 01/18/10 Beaufort Permit Application,

Table 2-1: Potential to Emit for Regulated NSR Pollutants

Pollutant	Potential to Emit, tpy	Significant Emission Rate, tpy
CO	464	100
NO_X	1371	40
PM	81	25
$PM_{2.5}$ (precursors NO_X and SO_2)	57	10 (40 for NO_X or SO_2)
PM_{10}	65	15
SO_2	2	40
VOC	96	40
Lead	0.111	0.6
Ozone (precursors VOC and NO_X)	NA	40 for VOC or NO_X
Fluorides	0	3
Sulfuric acid mist H_2SO_4	0.35	7
Hydrogen sulfide	0	10
Total reduced sulfur	0	10
Reduced sulfur compounds	0	10
Municipal waste combustor organics	<0.033 x 10^{-6}	3.5 x 10^{-6}
Municipal waste combustor metals	<0.12	15
Municipal waste combustor acid gases	<4	40
Municipal solid waste landfill emissions	0	50
Title VI, Class I or II substance	<0 1	*

* In 1996, EPA proposed a significant emission rate of 100 tpy for this category of pollutant and received no adverse comments on this issue. EPA subsequently concluded that PSD review is not necessary for this category of pollutants where they would be potentially emitted at substantially less than 100 tpy (EPA 02/24/98; EPA 05/19/98).

Because exploration drilling programs are not included in the list of source categories subject to a 100-tpy applicability threshold, the requirements of the PSD program apply if the project PTE is at least 250 tpy. From Table 2-1, it is evident that Shell's Beaufort exploration drilling program is a major PSD source because emissions of CO and NO_X exceed the major source applicability threshold of 250 tpy. In addition, emissions of CO, NO_X, PM, $PM_{2.5}$ (including the precursor NO_X), PM_{10}, and ozone precursors (VOC and NO_X) exceed the significant emission rate for each such pollutant. Emissions of SO_2 have been reduced below the significant emission rate as a result of the imposition of BACT on SO_2 emission sources on the Discoverer and Shell's request for a limit requiring the use of ULSD fuel in the Associated Fleet (discussed in Section 3.3 below). Emissions of sulfuric acid mist (H_2SO_4) are reduced below the significant emission rate as a result of Shell's use of ULSD in the Associated Fleet That request is being processed by EPA as an ORL for the Associated Fleet within 25 miles of the seaward boundary of the State of Alaska. Absent the BACT requirement on SO_2 emission sources on Discoverer, emissions of SO_2 from Shell's exploration drilling program would exceed the significant emission rate. Consequently, pursuant to 40 C.F.R. § 52.21(j)(2), Shell is required to apply BACT on the OCS source for CO, NO_X, PM, $PM_{2.5}$ (including the precursors NO_X and SO_2),

PM_{10}, SO_2 and ozone precursors (VOC and NO_X). Section 4 of the Statement of Basis contains a discussion of the BACT analysis for each of these pollutants. Additionally, and consistent with 40 C.F.R. §§ 52.21(k) and (m), these PTE values are used in the analysis of ambient air quality and demonstration that this source will not cause or contribute to a violation of any NAAQS or PSD increment. Section 5 of the Statement of Basis contains a discussion of the air quality impact analysis.

2.6 New Source Performance Standards (NSPS)

As discussed above, applicable NSPS apply to OCS sources. See 40 C.F.R. § 55.13(c). In addition, the PSD regulations require each major stationary source or major modification to meet applicable NSPS. See 40 C.F.R. § 52.21(j)(1). A specific NSPS subpart applies to a source based on source category, equipment capacity and the date when the equipment commenced construction or modification. The Discoverer contains emission units in four NSPS source categories: compression-ignition, internal-combustion engines; boilers; incinerators; and fuel tanks.

NSPS IIII, 40 C.F.R. Part 60, Subpart IIII, applies to stationary compression-ignition internal combustion (IC) engines, with the earliest applicability date being for units that were modified, or reconstructed after July 11, 2005 and the applicability date for newly manufactured engines that are not fire-pump engines being April 1, 2006. All diesel engines on board the Discoverer (FD-1 to FD-20), with the exception of the diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19), were manufactured before April 1, 2006 (Shell Beaufort Permit Application 01/18/10), and therefore are not subject to NSPS IIII. The diesel MLC compressor engines (FD-9 to FD-11), and the Caterpillar C7 Logging Winch Engine (FD-19) are Tier 3[9] engines to which NSPS IIII applies.

NSPS Dc, 40 C.F.R. Part 60, Subpart Dc, applies to boilers with a capacity of at least 10 MMBtu/hr. Since the two Discoverer boilers (FD-21 and FD-22) are rated at less than 10 MMBtu/hr, NSPS Dc does not apply.

NSPS CCCC, 40 C.F.R. Part 60, Subpart CCCC, applies to commercial and solid waste incinerators (CISWI) constructed after November 30, 1999. The incinerator on board the Discoverer (FD-23) was manufactured after that date and meets the definition of a CISWI. Therefore, it meets the general applicability criteria of NSPS CCCC unless it qualifies for one of the exemptions in 40 C.F.R. § 60.2020. Shell submitted an initial notification and exemption request to EPA as part of its OCS/PSD permit application on the grounds that the incinerator burns more than 30 percent municipal solid waste and refuse derived fuel and has the capacity to burn less than 35 tons per day of municipal solid waste and refuse derived fuel. See 40 C.F.R. § 60.2020(c)(2). EPA responded in a letter dated January 21, 2009, concurring with Shell's exemption claim and confirming that Shell must maintain records as provided in the exemption in order to continue to qualify for the exemption (EPA 01/21/09 CISWI Letter).

[9] As discussed in Section 4.2 below, EPA set new emission standards for nonroad diesel engines using a 3-tiered progression to lower emission standards. Each tier involves a phase-in by horsepower rating over several years. Tier 3 in NSPS IIII is the most stringent of the 3 tiers.

NSPS Subpart Ka, 40 C.F.R. Part 60, Subpart Ka, applies to petroleum liquids tanks with a capacity of greater than 420,000 gallons. The largest tank on board the Discoverer has a capacity of 142,140 gallons, well below the threshold for Subpart Ka to apply. NSPS Subpart Kb, 40 C.F.R. Part 60, Subpart Kb, applies to petroleum liquids tanks manufactured after July 1984. All of the tanks on board the Discoverer were manufactured before 1984, and therefore none are affected facilities subject to NSPS Subpart Kb.

In summary, the diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19) are subject to NSPS IIII and the incinerator is subject to requirements for maintaining an exemption from NSPS CCCC. As provided in 40 C.F.R. §§ 52.21(j)(1) and 55.13(c), the permittee must meet each applicable standard of performance under 40 C.F.R. Part 60. The applicable provisions of the NSPS have not been included in this proposed OCS/PSD permit, but Condition A.4, as well as 40 C.F.R. §§ 52.21(r)(3) and 55.6(a)(4)(iii), make clear that Shell is obligated to comply with all other federal requirements not included in this proposed OCS/PSD permit, including NSPS IIII and CCCC. All applicable standards promulgated pursuant to the NSPS program will be included in the Title V operating permit for Shell.

2.7 National Emission Standards for Hazardous Air Pollutants (NESHAP)

As discussed above, applicable NESHAPs promulgated under Section 112 of the CAA apply to OCS sources 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. See 40 C.F.R. § 55.13(e). In addition, the PSD regulations require each major stationary source or major modification to meet applicable standards under 40 C.F.R. Part 61, which are NEHSAPs. See 40 C.F.R. § 52.21(j)(1).

No source categories on board the Discoverer are currently regulated by NESHAPs promulgated at 40 C.F.R. Part 61. Consequently, the emission units on the Discoverer are not subject to the requirements of Part 61.

After the PSD program regulations were developed, EPA also promulgated Section 112 NESHAP regulations in 40 C.F.R. Part 63. Part 63 NESHAPs apply to a source based on the source category listing, and the regulations generally establish different standards for new and existing sources pursuant to Section 112. In addition, many Part 63 NESHAPs apply only if the affected source is a "major source" as defined in Section 112 and 40 C.F.R. § 63.2. A major source is generally defined as a source that has a PTE of 10 tpy or more of any single "hazardous air pollutant" or "HAP" or 25 tpy or more of all HAP combined. See Section 112(a)(1) and 40 C.F.R. § 63.2. An "area source" is any source that is not a major source. See Section 112(a)(2) and 40 C.F.R. § 63.2.

Shell has estimated emissions of HAP from Shell's exploration drilling program of 1.69 tpy for all HAP combined based on requested limits and other limits assumed under the permit application and supporting materials submitted to EPA (Shell Beaufort Permit Application 01/18/10, Table 2-2,). This makes the project an area source of HAP. The only emission units potentially subject to a current Part 63 NESHAP that applies to area sources are the compression-ignition internal combustion engines (RICE), identified as FD-1 to FD-20, which are potentially subject to NESHAP ZZZZ, 40 C.F.R. Part 63, Subpart ZZZZ. Under that rule, engines at area sources constructed before June 12, 2006 do not have to meet the requirements of 40 C.F.R. Part 63, Subparts A and ZZZZ, including the initial notification, if they fall within 40 C.F.R. § 63.6590(b)(3). See also 40 C.F.R. § 63.6590(a)(1)(iii). Engines FD-1 to FD-8, FD-12 to FD-18, and FD-20 fall within that exemption because they are existing compression-ignition stationary RICE constructed before June 12, 2006. The diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19) were constructed after June 12, 2006, and therefore qualify as new engines. As provided in 40 C.F.R. § 63.6590(c), however, because these are compression-ignition stationary RICE located at an area source, these emission units comply with Subpart ZZZZ by meeting the requirements of 40 C.F.R. Part 60, Subpart IIII, for compression-ignition engines. As discussed above in Section 2.6, FD-9 to FD-11 and FD-19 are subject to NSPS IIII.

At this time, it does not appear that emission units on the Discoverer are subject to any Section 112 standards except for the diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19), which comply with Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII. As discussed above, Condition A.4, as well as 40 C.F.R. §§ 52.21(r)(3) and 55.6(a)(4)(iii), make clear that Shell is obligated to comply with all other

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federal requirements not included in this OCS/PSD proposed permit. All applicable standards promulgated under Section 112 will be included in the Title V operating permit for Shell.

2.8 Corresponding Onshore Area Rules

The proposed permit will allow Shell to operate the Frontier Discoverer drillship and Associated Fleet for a multi-year exploration drilling program within Shell's current lease blocks in lease sales 195 (March 2005) and 202 (April 2007) on the Beaufort Sea OCS, within and beyond 25 miles from Alaska's seaward boundary. When the Discoverer drillship and/or its Associated Fleet are within 25 miles from Alaska's seaward boundary (Inner OCS) the applicable corresponding onshore area regulations apply. Thus the Frontier Discoverer drillship and Associated Fleet are subject to the applicable regulations in Article 3 of the State of Alaska Air Quality Control Regulations 18 Alaska Administrative Code 50.302 (Construction Permits) and 18 AAC 50.306 (Prevention of Significant Deterioration Permits), the applicable provisions of which have been incorporated into 40 C.F.R. Part 55 Appendix A. 75 FR 3387 and 75 FR 3392.

The provisions in this Statement of Basis and proposed permit that apply only to operations within 25 miles of the state seaward boundary are identified as "COA Regulations". A reference to any Alaska Administrative Code (AAC) provision refers to the AAC provisions incorporated into 40 C.F.R. Part 55 (See 75 FR 3387 and 75 FR 3392). Unless identified as a "COA Regulation," the provision in the permit applies in both the Inner and Outer OCS.

2.9 Title V

As specified in 40 C.F.R. § 55.13(f)(2), the requirements of the Title V operating permit program, as set forth at 40 C.F.R. Part 71 (Part 71), apply to OCS sources located beyond 25 miles of states' seaward boundaries. While within 25 miles of the State's seaward boundary, the applicable COA regulations pertaining to Title V operating permit regulations in 18 AAC 50 apply. Because the PTE for this project is greater than 100 tpy for several criteria pollutants, it is a major source under Title V and Part 71 and Shell must apply for an operating permit as provided in 40 C.F.R. § 71.5(a)(1)(i) within 12 months of first becoming an OCS on its current leases in the Beaufort Sea.

3 PROJECT EMISSIONS AND PERMIT TERMS AND CONDITIONS

3.1 Overview

Shell intends to implement their Beaufort Sea exploration drilling program through the use of the Frontier Discoverer drillship and the Associated Fleet.

As discussed above, determining a project's PTE is essential for determining the applicability of PSD, as well as the scope of PSD review, in particular, the pollutants that are subject to application of BACT, analysis of ambient air quality impacts from the project, analysis of air quality and visibility impact on Class I areas, and analysis of impacts on soils and vegetation. As discussed in Section 2 of this Statement of Basis, PTE reflects a source's maximum emissions of a pollutant from a source operating at its design capacity, including consideration of any physical or operational limitations on design capacity such as air pollution control equipment, emission limitations, and other capacity limiting restrictions that effectively and enforceably limit emissions capacity. See 40 C.F.R. §§ 52.21(b)(4) and 55.2. In the case of OCS sources, emissions from vessels servicing or associated with an OCS source are included in the "potential to emit" for an OCS source while physically attached to the OCS source and while en route to or from the source when within 25 miles of the source.

The detailed emissions calculations for the Beaufort Sea exploration drilling program are contained in the Shell 01/18/10 Permit Application Appendix A and in Environ International Corporation Revised Appendix A Email 01/20/10. In developing the emission inventory, EPA relied extensively on emissions data that were representative of the subject emission unit. For most emission units on board the Discoverer, EPA used emissions data from either the manufacturer or from literature that provided equivalent emissions data, such as data from similar emission units. In a very few instances, where representative data were not available, EPA relied on AP-42 to calculate projected emissions (EPA 1995 AP-42 and updates).

The emission inventory reflects application of emission limitations representing best available control technology or "BACT." As discussed in Section 4.1 of this Statement of Basis, a new major stationary source is required to apply BACT for each pollutant subject to regulation under the CAA that it would have the PTE in significant amounts. 40 C.F.R. § 52.21(j). Based on the emission inventory for the OCS source presented in Table 2-1, the emissions of CO, NO_X, PM, $PM_{2.5}$, PM_{10}, and VOC have a PTE exceeding their respective significant emission rates. Therefore, BACT must be determined for each emission unit on the Discoverer or that is part of the OCS source that emits these pollutants. Section 4 of this Statement of Basis contains a detailed discussion of the BACT determination for each emission unit subject to BACT. The proposed permit contains emission limitations that represent BACT and the emission inventory reflects these BACT-based emission limitations.

The emission inventory also reflects emission limitations and operating restrictions requested by Shell in its permit application as well as emission limitations and operating restrictions based on operating conditions assumed in the air quality impact analysis. The PSD regulations require that a source demonstrate that the allowable emissions increase from the new source, in conjunction with all other applicable increases or reductions (including secondary emissions), would not cause or contribute to a violation of the NAAQS or any applicable maximum allowable increase over the baseline concentration in any area. 40 C.F.R. § 52.21(k). The "applicable maximum allowable increase over baseline concentration in any area" are referred to as "increments" and are set forth in 40 C.F.R. § 52.21(c). After application of emission limitations that represent BACT, preliminary modeling indicated that additional restrictions on Shell's emissions and mode of operation would be needed to ensure attainment of the NAAQS and compliance with increment for some pollutants. Therefore, to ensure attainment of NAAQS and compliance with increment, the proposed permit imposes restrictions on emission units and Shell's mode of operation that are in addition to the application of BACT and that further limit operation of and emissions from the project.

The air quality impact analysis is discussed in Section 5. Emission limitations and operational restrictions are needed to demonstrate compliance with the annual increment for NO_X, attainment of the 24-hour $PM_{2.5}$ NAAQS, and compliance with the 24-hour PM-10 increment. Therefore, for most emission units, the permit contains an annual limit on NO_X, and 24-hour limits on PM_{10} and $PM_{2.5}$.

The permit contains monitoring, recordkeeping and reporting to monitor and ensure compliance with the emission limitations. This proposed permit requires stack testing of certain sources prior to commencement of each of the first three drilling seasons. Under this approach, not all emission units in a source category will be tested each year, but by the end of the first three drilling seasons, all of them will have been tested. Monitoring for the daily PM_{10} and $PM_{2.5}$ limits and the annual NO_X limit is based on emission factors derived from source tests, load monitoring or fuel usage, and annual fuel usage limits.

The number and range of stack testing of the newer and the smaller internal combustion engines (FD-9 to FD-20) and boilers (FD-21 to FD-22) are contained in Permit Conditions F.6, G.8, H.7, I.8, and J.5. EPA believes that testing at the specified operating loads or operating load ranges will continue to provide a reasonable assurance of compliance and considers operational and logistical concerns regarding stack testing concerns regarding the number of required source tests under the permit generally and the difficulty of stack testing some of these specific units due to their unique operation and function. There are no ambient air standards for VOC and predicted impacts of CO from this project are well below the standards. Therefore, EPA focused the monitoring regime on the BACT emission limits for these pollutants. For VOC and CO, testing at lower loads is expected to provide a higher emission factor than testing at full operating loads (see emissions data for various Caterpillar D343 configurations). The same is true with respect to visible emissions. EPA therefore believes that requiring stack testing for VOC, CO and visible emissions within the expected operating range of each engine will provide a reasonable indication of compliance for the VOC, CO, and visible emission limits for the newer engines, the smaller engines, and the boilers. See Permit Conditions F.6, G.8, H.7, I.7, and J.5. Because the data for NO_X and particulate matter is less conclusive, EPA is requiring stack testing at two load ranges – a high-load operating range and a lower-load operating range. EPA believes it is appropriate to extend this approach to the engines on board the icebreakers for the same reasons and has done so in this proposed permit. See Conditions O.10 and P.12.

While EPA understands that there may be practical challenges to testing the Deck Cranes (Units FD-14 and FD-15) emission units, EPA has insufficient information at this time to eliminate testing for these units. EPA is therefore proposing that, as with the other newer and smaller engines on the Discoverer, that stack testing be required at load ranges between 50 and 70 percent, or 80 and 100 percent. During the public comment period, EPA invites public comment and additional information from Shell and other commenters that further supports or opposes eliminating the stack testing requirement for the deck cranes.

Except for those conditions addressing notification, reporting and testing, the permit conditions contained in Sections B through R of the proposed permit apply only during the time that the Discoverer is an OCS source. Permit conditions addressing notification, reporting and testing apply at all times as specified. When the Discoverer is an "OCS Source" for purposes of the proposed permit is discussed in Section 2.5.1.

3.2 Generally Applicable Requirements

This section describes the permit conditions that apply generally to the Discoverer and the Associated Fleet and generally relate to permit administration or enforcement. These conditions apply in Outer and Inner OCS as specified. Permit Conditions that are included pursuant to COA regulations that have been incorporated in to 40 C.F.R. Part 55 are identified as "COA Regulations". The provisions of this permit apply to both the Inner OCS and Outer OCS unless specified to apply only to the Inner OCS.

Construction and Operation

Condition A.1 requires the permittee to construct and operate the OCS source and the Associated Fleet in accordance with its application and supporting materials and in accordance with the final permit, as provided in 40 C.F.R. §§ 55.6(a)(4)(i) and 52.21(r)(1).

Overlapping Requirements

Condition A.2 requires the permittee to comply both with conditions established in through the PSD permitting process and conditions that are the result of applying the COA regulations. In instances where two different permit conditions apply to the same emission unit or activity, the permittee must comply with both conditions.

Compliance Required

Condition A.3 specifies the enforcement authority for violation of OCS and PSD regulations and this permit, as provided in 40 C.F.R. §§ 55.9(a)-(b) and 52.21. Operation in violation of a permit term or condition is not authorized under this permit.

Compliance with Other Requirements

Condition A.4 makes clear that the permit does not relieve the permittee of the responsibility to comply fully with all other requirements of federal law as provided in 40 C.F.R. §§ 55.6(a)(4)(iii) and 52.21(r)(3). EPA is aware that Shell is required to obtain approval from other agencies before it is authorized to begin exploratory drilling in the Beaufort Sea and that there is pending litigation regarding the leases and exploration plan approval under which Shell proposes to conduct its exploratory drilling. EPA believes it is nonetheless appropriate to proceed with issuance of this OCS/PSD permit so that once Shell has all necessary approvals and authorizations to begin its exploratory drilling program on its leases in Lease Area 195 (March 2005) and 202 (April 2007), Shell can proceed with its exploratory drilling operations in Lease Area lease sales 195 and 202 without further delay consistent with a final OCS/PSD permit and all other necessary federal approvals and requirements. Condition A.4 makes clear Shell's obligation to satisfy all other federal requirements prior to commencing operation under this CAA permit.

Terms to Make Permit Enforceable

Condition A.5 makes clear that it is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the permit. The State of Alaska adopted this standard permit condition under 18 AAC 50.345(d) as part of the construction permit program and the condition is included in State construction permits.

Notification to Owners, Operators, and Contractors

Condition A.6 requires the permittee to notify all owners, operators and contractors of the source of the requirements of the permit, as provided in 40 C.F.R. § 55.6(a)(4)(iv).

Expiration of Approval to Construct

Condition A.7 contains provisions relating to automatic expiration of PSD permits as provided in 40 C.F.R. § 52.21(r)(2) in the event of failing to timely commence or complete construction or of a delay in construction. As provided in 40 C.F.R. § 124.5(g)(2), such permit expiration is not subject to the procedural requirements of 40 C.F.R. Part 124.

Permit Revision, Termination and Reissuance.

Condition A.8 contains provisions for revision, termination, or revocation and reissuance of the permit. Although 40 C.F.R. Part 124 does not contain such procedures for OCS or PSD permits, see 40 C.F.R. § 124.5(g)(1), EPA believes it has inherent authority to revise, terminate, or revoke and reissue a permit for cause, including a material mistake, inaccurate statements made during permit issuance, failure to comply with permit requirements, or ensuring compliance with the requirements of the CAA. Should EPA decide cause exists to revise, terminate, or revoke and reissue the permit, EPA will follow 40 C.F.R. Part 124. EPA intends to give Shell reasonable notice prior to initiating such action.

COA Regulations: Permit Revision, Termination and Reissuance.

Condition A.9 clarifies that the modification, revocation, and reissuance or termination or notice of planned change or anticipated noncompliance does not stay any permit condition. The State of Alaska adopted this standard permit condition under 18 AAC 50.345(f) as part of the construction permit program the condition is included in State construction permits. This condition applies within the Inner OCS.

Credible Evidence

Condition A.10 clarifies that the specification of a reference test method does not preclude the use of other credible evidence for the purpose of establishing whether or not the permittee is in compliance with a particular requirement. This is consistent with EPA's interpretation of the CAA requirements. See 40 C.F.R. §§ 52.12(c), 60.11(g), 61.12(e), and 62 FR 8314 (February 24, 1997).

Inspection and Entry

Condition A.11 includes EPA's inspection authority under Section 114 of the CAA. As discussed above, the permittee is a Title V source and must apply for a Title V operating permit under 40 C.F.R. Part 71 within one year of commencing operation. To facilitate

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incorporation of the requirements of this permit into the permittee's Title V permit, EPA has used the inspection language in 40 C.F.R. § 71.6(c).

Recordkeeping Requirements

Condition A.12 includes general recordkeeping requirements, including a record retention requirement of five years. Again, because Shell is subject to the Title V operating permit program and will be issued a Title V operating permit, EPA believes it is appropriate to make the general recordkeeping requirements in the permit consistent with Part 71. See 40 C.F.R. § 71.6(a)(3).

COA Regulations: Recordkeeping Requirements

Condition A.13 applies in the Inner OCS. It simply restates the COA regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit.

Agency Notifications

Condition A.14 specifies the EPA address to which information under the permit must be submitted.

Certification

Condition A.15 requires the certification of all documents submitted under the permit. Again, to facilitate incorporation of this requirement into Shell's Title V permit, EPA used language consistent with 40 C.F.R. § 71.5(d).

COA Regulations: Certification

Condition A.16 requires the permittee to comply with the certification requirements in 18 AAC 50.205. The State of Alaska adopted this standard permit condition under 18 AAC 50.345(j) as part of the construction permit program and this condition is included in State construction permits. This condition requires the permittee to certify any permit application, report, affirmation, or compliance certification submitted to EPA. To ease the certification burden on the permittee, the condition allows the excess emission reports to be certified with the OCS source operating report. This condition supplements the other reporting requirements of this permit and applies in the Inner OCS.

Severability and Property Rights

Conditions A.17 and A.18 contain standard language regarding severability of permit conditions and property rights. Again, to facilitate incorporation of these requirements into Shell's Title V permit, EPA used language consistent with 40 C.F.R. §§ 71.6(a)(5) and 71.6(a)(6)(iv). This language is consistent with the State's Severability and Property Rights Provisions in 18 AAC 50.345(e) and (g).

COA Regulations: Information Request

Condition A.19 applies in the Inner OCS and requires the permittee to submit requested information to the EPA. This standard permit condition is required in State construction permits under 18 AAC 50.345(i).

COA Regulations: Administration Fees

Condition A.20 ensures compliance with the applicable fee requirement in 18 AAC 50.400 – 50.405. This condition requires the permittee, owner, or operator to pay administration fees as set out in regulation. Paying administration fees is required as part of obtaining and holding a permit for operation within the Inner OCS.

COA Regulations: Assessable Emissions and Assessable Emissions Estimates.

Conditions A.21 and A.22 apply in the Inner OCS and implements the applicable requirements in 18 AAC 50.410 – 50.420. The regulations require all permits to include due dates for the payment of fees and the method the permittee may use to re-compute assessable emissions.

The State of Alaska adopted this condition as Standard Permit Condition I (revised as of August 25, 2004) under 18 AAC 50.346(b) and the condition is included in State construction permits. The default assessable emissions are generally potential emissions of each air pollutant in excess of 10 tpy authorized by the permit. Assessable emissions are defined as the quantity of each air pollutant for which emission fees are assessed.

This condition allows the permittee to calculate actual annual assessable emissions based on previous actual annual emissions. Assessable emissions are based on each air pollutant. Therefore, fees based on actual emissions shall be paid on any pollutant emitted whether or not the permit contains any limitation of that pollutant.

This condition specifies that, unless otherwise approved by EPA, calculations for assessable emission based on actual emissions use the most recent previous calendar year's emissions. Since each current year's assessable emission are based on the previous year, the EPA will not give refunds or make additional billings at the end of the current year if the estimated emissions and current year actual emissions do not match.

COA Regulations: Excess Emission and Permit Deviation Reports and Excess Emissions and Permit Deviation Notification Forms.

Conditions A.23 and A 24 apply within the Inner OCS and require the permittee to comply with applicable excess emission and permit deviation reporting requirement in 18 AAC 50.235(a)(2) and 18 AAC 50.240 except as provided in Condition A.24. The State of Alaska adopted this condition as Standard Permit Condition III (revised as of August 20, 2008) and Standard Permit Condition IV (revised as of August 20, 2008) under 18 AAC 50.346(b) as part of the construction permit program and these condition are included in State construction permits.

The permittee is required to notify EPA when emissions or operations deviate from the requirements of the permit. This condition satisfies two State of Alaska regulations related to excess emissions: the technology-based emission standard regulation and the excess emission regulation. Although there are some differences between the regulations, Conditions A.22 and A.23 satisfy the requirement of each regulation.

The reports themselves and the other monitoring records required under this permit provide monitoring of whether the Permittee has complied with the condition. Please note that there may be additional federally required excess emission reporting requirements.

Visible Emission Data Field Sheet

Condition A.25 provides the permittee with a Visible Emission Data Field Sheet to be used when conducting a Method 9 observation.

COA Regulations: Operating Reports

Condition A.26 implements compliance with the applicable requirement in 18 AAC 50.346(b)(6). The State of Alaska adopted this condition as a Standard Permit Condition VI (revised as of August 20, 2008) under 18 AAC 50.346(c) as part of the construction permit program and this condition is included in State construction permits. This Condition applies within the Inner OCS.

This condition restates the requirements for reports listed in the State regulation. The condition supplements the specific reporting requirements elsewhere in the permit

COA Regulations: Annual Compliance Certification

Condition A.27 applies within the Inner and Outer OCS and implements the applicable requirement in 18 AAC 50.040 (j)(4) and applies to State permits. This condition specifies the periodic compliance certification requirement and specifies a due date for the annual compliance certification.

COA Regulations: General Source Test Requirements

Condition A.28.1 applies within the Inner OCS and requires the Permittee to conduct source tests requested by EPA. The State of Alaska adopted this condition under 18 AAC 50.345(k) as part of its construction permit program standard permit condition and the condition is included in State construction permits. This condition ensures compliance with the applicable regulation in 18 AAC 50.220(a).

Conditions A.28.2 through A.28.4 apply within the Inner OCS and implements the applicable requirements in 18 AAC 50.220(b) and apply because the permittee is required to conduct source tests as set out in Conditions A.28.2 through A.28.4. These conditions supplement the specific monitoring requirements stated elsewhere in the permit.

Condition A.28.5 applies within the Inner OCS and implements the applicable requirements in 18 AAC 50.345(a) and applies when the source exhaust is observed for visible emissions. As provided in 18 AAC 50.345(a) the requirement for test plans, notifications and reports do not apply to visible emissions observations by smoke readers, except in connection with required particulate matter testing.

Condition A.28.6 applies within the Inner OCS and implements the applicable requirements in 18 AAC 50.345(l) – (o) and applies because the permittee is required to conduct source tests by this permit. Standard Conditions 18 AAC 50.345(l) – (o) are incorporated through this condition.

Condition A.28.7 applies within the Inner OCS and requires the permittee to reduce particulate matter data in accordance with 18 AAC 50.220(f). It applies when the permittee tests for compliance with the PM standard in 18 AAC 50.050 or 50.055. This condition incorporates a regulatory requirement for PM source tests. This condition supplements specific monitoring requirements stated elsewhere in the proposed permit.

3.3 Source-Wide Requirements

Section B of the permit contains air quality-related and operational limits that generally apply on a source-wide basis to the Discoverer and the Associated Fleet.

Drill Site Notification

Condition B.1 requires Shell to notify EPA at least 10 days prior to becoming an OCS source at any drill site. This proposed permit authorizes operation of the OCS source at multiple drill site locations on Shell's lease holdings in Lease Area lease sales 195 (March 2005) and 202 (April 2007) of the Beaufort Sea. The emissions limits and related monitoring, recordkeeping, and reporting apply at all drill site locations. Overall operation as an OCS source under the permit is limited to 168 days per rolling 12-month period.

Condition B.1.1 through B.1.4 requires the permittee to notify EPA of the proposed new location and probable duration of a drill site operation as well as to confirm that no Class I area or any area known to have a violation of applicable increment would be impacted by that specific operation.

Duration of Exploration Operations

Condition B.2 limits the annual duration of Shell's exploration operations in the Beaufort Sea. Shell's drilling season will largely be limited by sea ice conditions. Some variability can be expected from year to year. However, Shell expects to start drilling in July of each year and the drilling season is expected to last 5.5 months and has specifically requested that the proposed permit impose an annual limit of 168-days of operation as an OCS source. Condition B.2 limits the drilling season to the period between July 1 and December 31 of each year, which is referred to as the "drilling season" in the permit, and limits the number of days of operation as an OCS source to 168 calendar days each year. This is not a continuous 168-day period but an aggregation of all time operating as an OCS source during a given 12-month period. In addition, for each drill site, this condition requires Shell to document the exact location of the Discoverer when drilling, the lease block where drilling is occurring and the duration of the Discoverer as an OCS source at that site. This condition also clarifies that time recorded as an OCS source must include time spent drilling relief wells.

Drilling Season Notification

Condition B.3 requires Shell to notify EPA of the beginning and end of each drilling season.

Best Available Control Technology (BACT) for Sulfur Dioxide (SO2) Emissions from Discoverer Emission Units

Condition B.4 imposes a BACT limit of 0.0015 percent sulfur by weight on the fuel used in the Discoverer engines (except the propulsion engine), boilers, and incinerator. Shell is required to monitor fuel sulfur content by either testing the fuel being used or obtaining

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supplier certifications from the supplier. Note that Shell has committed to using only ULSD as the only fuel to be used by all engines and boilers that are part of this project, including support vessels. (Shell Beaufort Permit Application 01/18/10.). EPA's authority to impose emission limitations and other operating restrictions on the Discoverer, however, is limited to when the Discoverer is an OCS source.

SO_2 and Owner Requested Limit for Sulfuric Acid Mist for Associated Fleet

Condition B.5 limits the fuel sulfur content of fuel used in the Associated Fleet to a sulfur content of 0.0015 percent by weight, which Shell is required to monitor by either testing the fuel being used or obtaining supplier certifications from the supplier. This is based on Shell's commitment to using fuel with a maximum sulfur content of 0.0015 percent sulfur by weight in all engines on vessels in the Associate Fleet when operating north of the Bering Strait (Shell 12/09/09 Supp. App.). The emission inventory, permit limits, and other analyses supporting the proposed permit are based on the use of ultra-low sulfur fuel.

This permit condition also satisfies the requirement for an ORL in 18 AAC 50.225 for sulfuric acid mist which would apply when the source is within 25 miles of the seaward boundary of Alaska.

Marine Vessel Visible Emission Standards

Condition B.6 applies within the Inner OCS and implements the applicable requirements in 18 AAC 50.070 related to marine vessels. This condition imposes visible emission standards on the Associated Fleet when the Discoverer is an OCS source and the marine vessel is within 25 miles of the OCS source. Compliance with this standard is determined using the Method 9 Plan or Smoke/No Smoke Observations plan in Standard Permit Condition IX (revised as of August 20, 2008) under 18 AAC 50.346(c).

BACT for Particulate Matter Emissions (PM, PM10, and PM2.5) from Discoverer Diesel IC Engine Crankcase Ventilation

Condition B.7 implements the BACT requirement to control emissions PM, PM_{10} and $PM_{2.5}$ emissions from crankhouse ventilation. It requires that that each diesel IC engine, except for the MLC Compressor Engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19), be equipped with a closed crankcase ventilation (CCV) system. The MLC Compressor Engines and the Caterpillar C7 Logging Winch Engine have built-in crankcase emission controls.

COA Regulations: Industrial Process and Fuel-Burning Equipment Visible Emissions Standard and Visible Emissions Monitoring, Recordkeeping, and Reporting

Conditions B.8 through B.11 apply within the Inner OCS and implements the applicable requirements in 18 AAC 50.055(a). 18 AAC 50.055(a) applies to the operation of fuel burning equipment and industrial processes. Units FD-1 through 23 and FD-31 in Table 1 are fuel-burning equipment and industrial processes. The State of Alaska adopted this condition as a Standard Permit Condition IX (revised as of August 20, 2008) under 18 AAC 50.346(c) as part of the construction permit program and this condition is included in State construction permits. Condition B.8 prohibits the permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1).

The permittee must monitor, record, and report emissions in accordance with Conditions B.9 through B.11 of this permit.

Condition B.9.2 has slightly modified the State's Standard Permit Condition in this permit by removing the part of the Standard Permit Condition which requires semiannual method 9 observations. Shell stated in the Beaufort permit application that the Beaufort Sea drilling season will be July 1 through December 31 annually. Given the length of the drilling season (six months) EPA determined that the permittee would not be able to conduct the semiannual Method 9 observations contemplated in the State's Standard Permit Conditions.

Liquid fuel-fired burning equipment

For liquid fired fuel-burning equipment, Units FD-1 through FD-22 and FD-31, the MR&R requirements in the State's Standard Permit Condition IX.

Monitoring: In general, the visible emissions shall be observed by a Method-9 Plan or Smoke/No Smoke Plan as detailed in Condition B.9. Corrective actions such as maintenance procedures and either more frequent or less frequent testing may be required depending on the results of the observations.

Recordkeeping: The permittee is required to record the results of all visible emission observations and record any actions taken to reduce visible emissions.

Reporting: The permittee is required to report: 1) emissions in excess of the federal and state visible emission standard and 2) deviations from permit conditions. The permittee is required to include copies of the results of all visible emission observations with the OCS operating report.

COA Regulations: Industrial Process and Fuel-Burning Equipment Particulate Matter (PM) Standard; PM Monitoring, Recordkeeping and Reporting; PM Record Keeping for Diesel Engines; PM Monitoring for Liquid-Fired Boilers and Heaters; Particulate Matter Recordkeeping

Conditions B.12 through B.16 apply within the Inner OCS and implements the applicable requirements in 18 AAC 50.055(b). This requirement applies to operation of all industrial processes and fuel burning equipment in Alaska. The State of Alaska adopted this condition as a Standard Permit Condition IX (revised as of August 20, 2008) under 18 AAC 50.346(c) as part of the construction permit program and this condition is included in State construction permits. Units FD-1 through 22 and FD-31 of Table 1 are fuel burning equipment and industrial processes.

Condition B.12 prohibits emissions in excess of the state PM (also called grain loading) standard applicable to fuel-burning equipment and industrial processes. The Permittee must establish by actual visual observations that can be supplemented by other means, such as a defined Stationary Source Operation and Maintenance Program, that the stationary source is in continuous compliance with the State's emission standards for visible emissions and particulate matter.

These conditions detail a stepwise process for monitoring compliance with the State's visible emissions and particulate matter standards for liquid and gas fired sources. Equipment types covered by these conditions are internal combustion engines, turbines, heaters, boilers, and flares. Initial monitoring frequency schedules are established along

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with subsequent reductions or increases in frequency depending on the results of the self-monitoring program.

Reasonable action thresholds are established in these conditions that require the Permittee to progressively address potential visible emission problems from sources either through maintenance programs and/or more rigorous tests that will quantify whether a specific emission standard has been exceeded.

Monitoring recording and reporting requirements are listed in Conditions B.13 through B.16. The permittee must establish actual visible observation which can be supplemented by other means to demonstrate that the emission unit is in continuous compliance with the State's emission standards for PM.

COA Regulations: Sulfur Compound Emissions Standard; Sulfur Compound Monitoring, Recordkeeping and Reporting Liquid Fuel-fired Sources

Conditions B.17 through B.19 apply within the Inner OCS and require the permittee to comply with the sulfur compound emission standard for all fuel-burning equipment and industrial processes. This requirement applies to operation of all industrial processes and fuel burning equipment in Alaska. The State of Alaska adopted Conditions B.17 and B.19 as a Standard Permit Condition XI (revised as of August 25, 2004) under 18 AAC 50.346(c) as part of the construction permit program. In addition Standard Permit Condition XII (August 25, 2004) was adopted under 18 AAC 50.345(c). As a result, these standard permit conditions are included in State construction permits. Units FD-1 through 22 and FD-31 of Table 1 are fuel-burning equipment and industrial processes.

The permittee may not cause or allow the affected equipment to violate this standard. Conditions B.18 and B.19 contain the COA Regulations for recordkeeping and reporting requirements to ensure compliance with the Sulfur Compound Emission Standard.

General Testing Requirements

Condition B.20 contains general testing requirements related to how the stack tests must be conducted. It also contains procedures for approval of an alternative to or a deviation from a reference test method. Condition B.20.2 is included for consistency with 18 AAC 50.345 and applies only within the Inner OCS for source tests requested under Condition A.28.1

Prohibited Activities

Condition B.21 prohibits Shell from flow testing wells, flaring gas, storing liquid hydrocarbons recovered during well testing, or refueling within 25 miles of the Discoverer while the Discoverer is an OCS source. Shell's application states that, during its planned drilling campaign using the Discoverer, they have no plans to conduct these activities. Because EPA has therefore not estimated or analyzed emissions from these activities, Condition B.21 prohibits them.

Monthly Emissions Calculations

Condition B.22 requires Shell to calculate monthly emissions of pollutants of CO, NO_X, $PM_{2.5}$, PM_{10}, SO_2 and VOC.

Rolling 12-Month Emissions Calculations

Condition B.23 requires a monthly calculation of rolling-12-month emissions of each of these pollutants for the prior 12-month period. Condition B.24 requires Shell to notify EPA if any of the emission or throughput limits in the permit are exceeded.

Reporting

To the extent not included in Condition A.23 for the Inner OCS, Condition B.24 requires Shell to report any exceedance of an emission limit as a throughput to the EPA within 3 business days.

Good Operating and Maintenance Requirements.

All of the emissions estimates are based on the equipment and control equipment being operated using good practices. Consequently, Condition B.25 requires the use of good air pollution control practices for minimizing emissions and is derived from language in the general provisions of the NSPS and NESHAP. See 40 C.F.R. §§ 60.11(e) and 63.6(e).

COA Regulations: Good Air Pollution Control Practice.

Condition B.26 applies within the Inner OCS and ensures compliance with the applicable requirement in 18 AAC 50.346(b)(5) and applies to all emission units except those subject to federal emission standards, those subject to continuous emission parametric monitoring, and for insignificant emission units. This condition requires the permittee to comply with good air pollution control practices for all sources.

Maintaining and operating equipment in good working order is fundamental to preventing unnecessary or excess emissions. The State of Alaska adopted this condition as a Standard Permit Condition II (revised as of August 25, 2004) under 18 AAC 50.346(b) as part of the construction permit program and this Standard Permit Condition included in State construction permits. The State condition is based on the assumption that good maintenance is performed. Without appropriate maintenance, equipment can deteriorate more quickly than with appropriate maintenance.

The permittee is required to keep maintenance records to show that proper maintenance procedures were followed and to make the records available to the EPA. The EPA may use these records as a trigger for requesting source testing if the records show that maintenance had been deferred. EPA also has authority under Section 114 of the CAA to require source testing at any time to determine compliance with CAA requirements.

COA Regulations: Air Pollution Prohibited.

Condition B.27 applies within the Inner OCS and implements the applicable requirement in 18 AC 50.110. Air Pollution Prohibited requirements apply to the stationary source because the stationary source will have emissions. The State of Alaska adopted this condition as a Standard Permit Condition II (revised as of August 25, 2004) under 18 AAC 50.346(a) as part of the construction permit program and is included in State construction permits.

The condition prohibits the permittee from causing any emission which is injurious to human health or welfare, animal or plan life, or property, or which would unreasonably interfere with the enjoyment of life or property. While the other permit conditions and emission limitations should ensure compliance with this condition, unforeseen emission impacts can cause violations of this standard. These violations would go undetected except for complaints from affected persons. Therefore, to monitor compliance, the permittee must monitor and respond to complaints.

The permittee is required to report any complaints and injurious emissions. The permittee must keep a record of the date, time, and nature of all complaints received and summary of the investigation and corrective actions undertaken for these complaints and to submit copies of these records upon request by EPA.

The EPA will determine whether the necessary actions were taken. No corrective actions are necessary if the complaint is frivolous or there is not a violation of 18 AAC 50.110; however this condition is intended to prevent the permittee from prejudging that complaints are invalid.

3.4 Frontier Discoverer Drillship

Sections 3.4 through 3.8 of the Statement of Basis describe each emission unit or group of emission units on the Discoverer and the Associated Fleet in more detail. It also provides additional explanation for the basis for the emissions calculations, explains the BACT or other emission limitations applicable to the emission unit(s), and explains the monitoring, recordkeeping and reporting for the emission unit(s).

The Discoverer is a turret-moored drillship that is able to move under its own power. The propulsion unit will not be used while the drillship is an OCS source (see Section 2.5.1). While an OCS source, the Discoverer will use a variety of pollutant-emitting equipment and/or activities. The emission units on board the Discoverer are listed in Table 3-1. All of these emission units are existing equipment, with the exception of the MLC air compressors, which are new engines.

Table 3-1: Frontier Discoverer Emission Units

ID	Description	Make and Model	Rating[a]
FD-1 – 6	Generator Engines	Caterpillar D399 SCAC 1200 rpm	1,325 hp
FD-7	Propulsion Engine	Mitsubishi 6UEC65	7,200 hp
FD-8	Emergency Generator	Caterpillar 3340	131 hp
FD-9 – 11	MLC Compressor Engines	Caterpillar C-15	540 hp
FD-12 – 13	HPU Engines	Detroit 8V-71	250 hp
FD-14	Port Deck Crane Engine	Caterpillar D343	365 hp
FD-15	Starboard Deck Crane Engine	Caterpillar D343	365 hp
FD-16 – 17	Cementing Unit Engines	Detroit 8V-71N	335 hp
FD-18	Cementing Unit Engine	GM 3-71	147 hp
FD-19	Logging Winch Engine	Caterpillar C7	250 hp
FD-20	Logging Winch Engine	John Deere PE4020TF270D	35 hp
FD-21 – 22	Heat Boilers	Clayton 200	7.97 MMBtu/hr
FD-23	Incinerator	TeamTec GS500C	276 lb/hr
FD-24 -30	Fuel Tanks	Not applicable (NA)	Various
FD-31	Supply Ship Generator Engine(s)	Generic	584 hp

ID	Description	Make and Model	Rating[a]
FD-32	Drilling Mud System	NA	NA
FD-33	Shallow Gas Diverter System	NA	NA
FD-34	Cuttings/Mud Disposal Barge[b]	NA	NA

[a] Permit conditions may limit operation to less than rated capacity.
[b] Permit conditions prohibits cuttings/mud disposal barge from emitting any air pollutants.

As noted in Table 3-1, most of the emission units on board the Discoverer are internal combustion engines. The Discoverer is also equipped with two boilers. Both the engines and the boilers are fired on a light-distillate, liquid fuel equivalent to No. 1 or 2 grade diesel. As discussed previously, Condition B.4 requires Shell to use only fuels with very low sulfur content in the Discoverer emission units (0.0015 percent sulfur by weight). This fuel must also be used in the Discoverer incinerator burner.

3.4.1 Discoverer Generator Engines (FD-1 to FD-6)

Six Caterpillar D399 generator sets provide the primary systems power for the drilling as well as the ship utilities. The Discoverer D399 units are each rated at 1325 horsepower (hp), and are separate circuit aftercooled (SCAC). These D399 engines are specified to produce peak power at 1200 revolutions per minute (rpm). Each engine can be operated at varying load levels throughout the drilling process. Shell expects that no more than five engines will operate at one time, leaving one as a spare. The normal ramping procedure is to operate the fewest number of engines needed to power the load and as load increases, to add on engines so that the operating engines are at 50 percent capacity or greater. In recognition of the excess capacity and to limit maximum emissions, Shell has requested that the engines be limited to operate at no more than 71 percent of rated capacity, in aggregate.

As discussed in Section 4, EPA is proposing that selective catalytic reduction (SCR) and oxidation catalyst control devices represent BACT for the D399. These controls are to be retrofitted by D.E.C. Marine AB, a Swedish company with extensive experience in installing ship emission control systems for NO_X. The analyses in support of this permit action were based on the SCR units and the oxidation catalysts being fully operational at any time that the engine they serve are running. Conditions C.1 and C.2 reflect these requirements.

The D.E.C. Marine AB control guarantees for NO_X and CO are based on the engines running at between 50 and 100 percent load. Based on Shell's discussions with the vendor, Shell is confident that the SCR and oxidation catalyst are able to meet the proposed emission rates, even at lower loads. As a result, the emission inventory and modeling analyses are based on these emission rates at all loads. Therefore, the BACT permit conditions contained in Condition C.3 are based on these limits applying at all operating conditions. Condition C.4 contains emission limits for $PM_{2.5}$ (daily), PM_{10} (daily) and NO_X (annual) that arise out of emission limits requested by Shell. Again, these limits apply at all operating conditions.

D.E.C. Marine AB does not guarantee an emission rate for emissions of VOC. Instead, they indicate that emissions reduction can be expected between 70 and 90 percent. Shell has used the lower range as part of their representation of PTE. Shell has indicated that the oxidation catalyst will result in a 50 percent reduction in emissions of particulate matter of all sizes. EPA's emission inventory reflects these assumptions and requires stack testing (Condition C.6) to assure that actual emission rates comply with the BACT emission limits.

EPA believes that monitoring electrical power output produced by the generators will provide a reasonable means of assuring compliance with the applicable emission limits. The main generators comprise six Caterpillar D399 engines rated at 1325 hp each, with an aggregate rating of 7950 hp. Shell has requested a limit to operate at no greater than 71 percent of this rating, or 5,645 hp. This is equivalent to 4209 kW (mechanical). In Shell's November 23, 2009 submittal, Shell presented generator efficiencies for a variety of gensets, with efficiencies ranging from 92 percent to 96 percent (Shell 11/23/09 Supp. App.). Given the apparent age of the Discoverer's gensets and the lack of specific information regarding the efficiencies of the Discoverer's gensets, EPA believes it is appropriate to use the most conservative value (i.e. 92 percent) to represent generator efficiency for these emission units. This would result in an hourly limit of 3,872 kWe-hr.

Condition C.5 limits the power output in aggregate for these gensets to 3,872 kWe and, in conjunction with the emission factors derived from the stack testing required in Condition C.6, is used to monitor compliance with emission limits for these engines. Condition C.6 requires Shell to conduct stack testing for CO, NO_X, $PM_{2.5}$, PM_{10}, VOC, ammonia and visible emissions and to monitor certain parameters in addition to determining the efficiency for each engine. In addition to monitoring power output (Condition C.7), Shell is required to monitor and record parameters related to good operation of the SCR. Condition C.7.5 requires Shell to monitor and record hourly NO_X emissions.

3.4.2 Discoverer Propulsion Engine (FD-7)

Section 2.5.1 discusses two alternative approaches for when the Discoverer will be considered an OCS source under the proposed permit. Under either approach, the propulsion engine will have no emissions during the time the Discoverer drillship is an OCS source.

Based on Shell's application and EPA review, the proposed permit includes two permit conditions regarding use of this emission unit. Condition D.1 prohibits the use of the propulsion engine while the Discoverer is an OCS source. Condition D.2 requires Shell to report to EPA any use of this engine while the Discoverer is an OCS source.

3.4.3 Discoverer Emergency Generator (FD-8)

The Discoverer will have one emergency generator, powered by a 131 hp Caterpillar 3304 engine, for use in powering the basic drillship utilities, which include domestic and worker safety devices. This generator will not be used for powering drilling equipment. There are no planned uses of the emergency generator except for weekly exercising which involves operation for approximately 120 minutes (two hours) at loads up to capacity.

In estimating emissions from this generator, EPA relied upon Caterpillar emissions data from an EPA Health Assessment Document (EPA 5/02 Diesel Health Assessment). Because this document did not feature data specific to the 3304 model engine, EPA used the maximum emissions rate for each pollutant from all Caterpillar engines as a conservative assessment of emissions from the Caterpillar 3304 engine. In estimating $PM_{2.5}$ emissions, EPA conservatively assumed that all PM_{10} emissions were also $PM_{2.5}$.

Based on Shell's application and EPA review, Condition E.1 prohibits operations of the emergency engine in excess of 120 minutes during any single day and 48 hours during any rolling 12-month period. Condition E.2 requires Shell to record all usage of this engine while the

Discoverer is an OCS source and, per Condition E.3, to report any deviation from the operational restrictions.

3.4.4 Mud LineCellar Compressor Engines (FD-9 to FD-11)

The mud line cellar (MLC) air compressors are used for drilling the MLCs, which is the initial drilling activity. Shell expects to use these compressors for about one week per well. The compressors will be powered by three 540-hp Caterpillar C-15 engines, and will be used at between 50 and 100 percent capacity during the week needed to evacuate the MLC. Shell has requested an annual fuel limit of 81,346 gallons for all three engines combined. Hourly and daily emissions are based on operation of all three engines at maximum capacity. The C-15 engines are new and are required to meet EPA's Tier 3 emission standards for nonroad engines (40 C.F.R. § 89.112).[10] The Tier 3 standards have a single limit for NO_X and VOC combined. In the emission inventory, the conservative maximum emission rate of 4.0 g/kW-h was used for each pollutant (i.e. NO_X and VOC). These engines are also subject to a PM limit of 0.20 g/kW-h under the Tier 3 standards. In the emission inventory, this emission rate of 0.20 g/kW-h was also used to estimate emissions of PM_{10} and $PM_{2.5}$, a conservative assumption. Particulate matter emissions are expected to be even lower as a result of the addition of an oxidation catalyst and the passage of the exhaust gases through that system.

Conditions F.1 and F.2 contain the BACT emission limits and requirements for these engines. Condition F.3 of the permit contains the annual NO_X emissions limit that results from the fuel limit requested by Shell, 81,346 gallons for all three engines combined during any rolling 12-month period, which is contained in Condition F.5. The annual NO_X limit and fuel limit each apply to all three engines in aggregate. In contrast, Condition F.4 imposes emissions limits for $PM_{2.5}$ and PM_{10} on a per-unit base. To monitor fuel usage, Condition F.7 requires the permittee to install, properly maintain and operate totalizing, nonresettable diesel fuel flow meters on each engine and to monitor and record the daily use of fuel in each engine. Condition F.6 requires Shell to stack test one engine in each of the first three drilling seasons for CO, VOC and visible emissions within one load range, and NO_X, $PM_{2.5}$ and PM_{10} within two different load ranges.

3.4.5 Hydraulic Power Units Engines (FD-12 to FD-13)

The hydraulic power units (HPU) are also used for drilling the MLCs. The HPU units are powered by a pair of 250-hp Detroit Diesel 8V-71 engines. These units will be used very similarly to the MLC compressors. Shell has requested an annual fuel limit of 44,338 gallons for both engines combined. Hourly and daily emissions are based on operation of both engines at maximum capacity.

EPA relied on the EPA Health Assessment Document for engine-specific data (EPA 5/02 Diesel Health Assessment). This source had several data points for this engine, and EPA used the maximum of the data values for each pollutant as a conservative assessment of emissions. This document only listed emissions data for PM, not PM_{10} or $PM_{2.5}$. Consequently, the values for

[10] As discussed in Section 4.2 below, EPA set new emission standards for nonroad diesel engines using a 3-tiered progression to lower emission standards. Each tier involves a phase-in by horsepower rating over several years. Tier 3 in 40 C.F.R. Part 60, Subpart IIII, is the most stringent of the 3 tiers.

PM were assumed to be representative of PM_{10} and $PM_{2.5}$ emission rates, again, a conservative assumption.

The proposed permit requires Shell to use a catalytic diesel particulate filter (CDPF) on each engine in this group for control of oxidizable emissions (volatile organics, carbon monoxide, and hydrocarbon particulate matter). The filter vendor Shell is using, CleanAIR Systems, has indicated that with the correct filter on each engine, and with adequate regeneration, the filters are capable of 85 percent reduction in PM emissions, 90 percent reduction in CO emissions, and 90 percent reduction in VOC emissions. (Shell Beaufort Permit Application 01/18/10). CleanAIR Systems has also indicated that the exhaust temperature will need to be above 300 degrees Celsius (^oC), or 572 degrees Fahrenheit (^oF), for at least 30 percent of the engine operating time for proper filter regeneration using ultra-low sulfur fuel (i.e. 0.0015 percent sulfur by weight). (Shell Beaufort Permit Application 01/18/10, Appendix C).

Condition G.1 requires use of the CDPF whenever the engine being served by that CDPF is in operation. The CDPFs are equipped with a HiBACK monitor and alarm system that monitors exhaust pressure and temperature. Condition G.1.1 requires that each CDPF be equipped with a fully operational HiBACK system and, in order to assure adequate regeneration, Condition G.1.2 requires temperature over the course of a day of operation to be at least 300 ^oC for at least 30 percent of operational time. Conditions G.2 and G.3 reflect the BACT emission limits, including a requirement to use good combustion practices to control NO_X emissions.

Condition G.4 of the permit contains the annual NO_X emissions limit that resulted from the fuel limit requested by Shell, 44,338 gallons for both engines combined during any 12-month period, which is contained in Condition G.6. The annual NO_X limit and the fuel limit apply to both engines in aggregate. In contrast, Condition G.5 contains emissions limits for $PM_{2.5}$ and PM_{10} that apply on a per-unit base. To monitor fuel usage, Condition G.9 requires the permittee to install, properly maintain and operate totalizing, nonresettable diesel fuel flow meters on each engine and to monitor the daily use of fuel in each engine as well as other parameters necessary to assure compliance with the limitations in this section of the permit. Condition G.8 requires Shell to stack test one engine each of the first two drilling seasons for CO, VOC and visible emissions at one load, and NO_X, $PM_{2.5}$ and PM_{10} at two different loads.

Shell intends to operate the HPU engines under one of three operating scenarios: Base Operating Scenario, Alternative Operating Scenario #1 and Alternative Operating Scenario #2. Under each of these scenarios, Shell will operate under different daily fuel limits and coordinate operation of these engines with operation of the incinerator (FD-23). Under the Base Operating Scenario, the HPU engines shall not be operated while the incinerator is allowed to incinerate no greater than 1300 lbs of waste in any calendar day. With Alternative Operating Scenario #1, the HPU engines are allowed to combust up to 352 gallons of fuel per calendar day in both engines in aggregate, while the incinerator is limited to 800 lbs of waste during the same day. Under Alternative Operating Scenario #2, the HPU engines' fuel limit rises to 704 gallons per calendar day in both engines in aggregate, and the incinerator limit is reduced to 300 lbs of waste during the same day. The conditions establishing the alternative operating scenarios for the HPU engines are contained in Condition G.7.

3.4.6 Deck Cranes (FD-14 to FD-15)

The Discoverer is equipped with two deck cranes that are mounted on and rotate on pedestals. One crane is located on the port side of the drillship and the other crane is located on the starboard side. Each crane is powered by a Caterpillar D343 engine rated at 365 hp. The engines are mounted on the pedestal with the rotating crane. The cranes are used intermittently to move materials around the deck and to on-load supplies from the supply ship. Shell has requested both daily and annual limits on the amount of fuel combusted in these two emission units. As with the HPU engines, the crane engines will have CDPFs for control of particulate matter, CO, and VOC.

Emissions from the Caterpillar D343 engines were estimated from the manufacturer's emissions data. Permit conditions for these emission units parallel those for the HPU engines. Specifically, Condition H.1 contains the requirement to use the CDPF, HiBACK system and exhaust temperature limits. Conditions H.2 and H.3 contain the BACT limitations, while Condition H.4 specifies the annual emission limit for NO_X, and Condition H.5 contains the daily emission limits for $PM_{2.5}$ and PM_{10}. Condition H.6 specifies the annual fuel limit, while Conditions H.7 and H.8 contain the stack testing, monitoring, recordkeeping and reporting requirements.

3.4.7 Cementing Units and Logging Winch Engines (FD-16 to FD-20)

The three cementing units are used intermittently when drilling is interrupted for forcing a liquid slurry of cement and additives down the casing and into the annular space between the casing and the wall of the borehole when the drill pipe is pulled out of the hole, or for plugging and abandoning wells. The cementing units are also used intermittently as high pressure pumps for hydrostatically testing various well equipment and drilling components, such as the wellhead connections, the blowout preventer, and other connections. The two logging winches are used to gather information from each well when the drill stem is removed.

The cementing unit and logging winch engines will all be equipped with CDPFs. FD-19 is a Caterpillar C7 engine that meets EPA's Tier 3 emission standards. Although the logging winches will operate only when the cementing units are not used and the prime movers are operating at a low load, Shell is not requesting these as operating restrictions and has instead modeled all described units operating concurrently. The logging winches operate at variable and unpredictable loads.

To estimate emissions from these emission units, EPA relied on the EPA Diesel Health Assessment Document for engine-specific data. (EPA 05/02 Diesel Health Assessment). As noted earlier, this document had several data points for the Detroit 8V-71. All of the "-71" series are from the same family of engines, with a different number of cylinders. In addition, the GM 3-71 engine (FD-18) is manufactured by Detroit Diesel. Accordingly, for the GM 3-71 engine, EPA used the maximum of the data values for each pollutant from any -71 series engine as a conservative assessment of emissions. As also noted before, this document only listed emissions data for PM, not PM_{10} or $PM_{2.5}$. Consequently, the values for PM were assumed to be representative of PM_{10} and $PM_{2.5}$ emission rates, a conservative assumption. Because the logging unit engines are Tier 2 and Tier 3 engines, EPA used the corresponding limits in 40 C.F.R. Part 89 to estimate the PTE from these engines.

Permit conditions for these emission units parallel those for the HPU engines. Specifically, Condition I.1 contains the requirement to use the CDPF, HiBACK system and exhaust temperature limits. Conditions I.2 and I.3 contain the BACT limitations for each of the engines, while Condition I.4 specifies the annual emission limit for NO_X, and Condition I.5 contains the daily emission limits for $PM_{2.5}$ and PM_{10}. For this group of engines, Shell requested and EPA is imposing a daily fuel limit in addition to an annual fuel usage limit. Condition I.6 specifies the annual and daily fuel limits while Conditions I.7 and I.8 contain the stack testing and monitoring requirements.

3.4.8 Heat Boilers (FD-21 and 22)

The Discoverer has two Clayton 200 diesel-fueled boilers for providing heat for domestic and work space heating purposes. Shell's intent is to use one boiler for normal operation and the second as a backup although there could be times when both would operate. For this permit, Shell is not requesting any operational limits, and so, the PTE for the boilers has been determined based on continuous operation for 168 days at full load. Because emissions are based on operation as described above, limitations on fuel usage or hours of operation are unnecessary. Emissions were estimated based on emissions data from the manufacturer. EPA conservatively assumed that all PM_{10} was $PM_{2.5}$.

In addition to the BACT limits in Conditions J.1 and J.2, Section J of the permit contains conditions that are very similar to those imposed on the engines in previous conditions of the permit. Condition J.3 contains an annual emission limit for NO_X and Condition J.4 contains daily emission limits for PM_{10} and $PM_{2.5}$. Condition J.5 contains stack testing requirements and Condition J.6 specifies the monitoring, recordkeeping and reporting required of Shell.

3.4.9 Waste Incinerator (FD-23)

Shell intends to dispose of domestic and other non-hazardous materials in a small two-stage, batch-charged unit capable of burning 276 lbs/hr (125 kg/hr) of solid trash or 1,000 lb of liquid sewage per day. In developing the emissions estimate, EPA relied on AP-42 (EPA1995 AP-42 and updates) emissions data for a larger class of incinerators because the manufacturer's emissions data is oriented to satisfying European emission standards, and was not in a format that could be converted into a throughput-based emission factor. For emissions of CO, NO_X, VOC and lead, EPA used the worst case emission factor for combustion of domestic waste or sewage. In using this approach, the monitoring regime can be simplified and does not need to require maintaining separate logs for the types of material incinerated.

For emissions of $PM_{2.5}$, PM_{10} and SO_2, Shell requested throughput-based limits. These values are used in the emission inventory, and are reflected in emission limits in the permit (Condition K.5). These limits, expressed in lbs/ton of waste incinerated, do not require additional monitoring because they are the same as the BACT emission limits in the permit (Condition K.1). Shell also requested throughput limits that are below rated capacity in order to demonstrate that they meet NAAQS and increment. These throughput limits and their related PTE limits for NO_X, $PM_{2.5}$ and PM_{10} are contained in Conditions K.3, K.4 and K.5 respectively. In addition to these conditions, the permit also requires stack testing (Condition K.8) and monitoring, recordkeeping and reporting (Condition K.9).

Shell intends to operate the incinerator in coordination with operation of the HPU engines (FD-12 to FD-13) under one of three operating scenarios: Base Operating Scenario, Alternative Operating Scenario #1 and Alternative Operating Scenario #2. Under each of these scenarios, Shell will operate under different daily incineration and fuel limits. Under the Base Operating Scenario, the HPU engines shall not be operated while the incinerator is allowed to incinerate up to 1300 lbs of waste in any calendar day. With Alternative Operating Scenario #1, the HPU engines are allowed to combust up to 352 gallons of fuel per calendar day in both engines in

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aggregate, while the incinerator is limited to 800 lbs of waste during the same day. Under Alternative Operating Scenario #2, the HPU engines' fuel limit rises to 704 gallons per calendar day in both engines in aggregate, and the incinerator limit is reduced to 300 lbs of waste during the same day. The conditions that establish the alternative operating scenarios for the incinerator are contained in Condition K.7.

Condition K.11 applies within the Inner OCS and ensures compliance with the applicable visible emission requirements in 18 AAC 50.055(a). This condition prohibits the permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1).

The permittee must monitor, record, and report emissions in accordance with Condition B.10 of this permit.

3.4.10 Discoverer Diesel Fuel Tanks (FD 24 – 30)

The Discoverer is equipped with a number of fuel tanks that are used to store the fuel used in the various emission units on board the drillship. Table 3-2 lists the tanks on board the Discoverer as well as their respective capacities.

Table 3-2: Discoverer Diesel Fuel Tanks

ID	Tank Capacity (m^3)	Tank Capacity (gallons)
FD-24	538	142,140
FD-25	267	70,542
FD-26	267	70,542
FD-27	179	47,292
FD-28	150	39,630
FD-29	150	39,630
FD-30	135	35,667

The fuel stored in the tanks is the diesel used to fuel the emission units on board the Discoverer. Diesel fuel has a very low vapor pressure, and so the tanks will have very low emissions – about 24 lbs of VOC per year (Shell Beaufort Permit Application 01/18/10). Consequently, the proposed permit contains no conditions regarding operation of these tanks.

3.4.11 Supply Ship Generator Engine (FD-31)

Although the Discoverer is provisioned and supplied at the beginning of a drilling season, additional supplies are expected to be brought out to the drillship during the course of the drilling season. Shell is expecting to re-provision the Discoverer at intervals of two to four weeks, for a maximum of eight re-provisionings per season.

Shell will use a leased vessel to conduct these resupply operations. The most recent plans call for a foreign-flagged vessel named Jim Kilabuk. The Jim Kilabuk will provision out of Canada, and a different vessel would be used if supplied out of Alaska. Shell is also considering the possibility of using a barge and tug combination. There will be no need for the supply ship to be within 25 miles of the Discoverer except for the time needed to approach, deliver, and leave the area. If the supply ship makes a delivery, it will attach to the Discoverer for less than 12 hours, during which time only one of its 292-hp generators will be operating. To simplify the monitoring regime for this very occasional source, stack testing has been scaled back to testing at only one load. This will require Shell to assume that the generator engine is operated at full load while the supply ship is attached to the Discoverer. The permit does not specify a particular vessel, but does require that the rated capacity of the generator be no greater than included in the modeling analysis.

If a barge and tug combination is used the barge will attach to the Discoverer during which time it cannot operate any emission units or emit any pollutants. At no time shall the tug attach to the Discoverer.

The supply ship and tug/barge requirements are contained in Conditions L.1 through L.6. Condition L.1 contains operational limits on the duration and frequency of supply ship visits. Conditions L.2 and L.3 contain PTE annual emission limits and PTE daily emission limits, respectively. Condition L.4 contains the stack testing requirements and Condition L.5 specifies the monitoring, recordkeeping and reporting required of Shell. Condition L.6 specifies the requirements if a barge/tug are used.

3.4.12 Mud Drilling System (FD-32)

The wells Shell proposes to drill in the Beaufort Sea will use the conventional rotary drilling and fluids circulating systems. The fluids circulating system is comprised of drilling fluid, which is pumped down the drill string, through orifices in the bit, and back to the surface where it is directed into storage pits on the rig. After solids removal and mud conditioning, the drilling fluid is directed from the pits back down the drill string. The drilling fluid cools and lubricates the drill bit, carries cutting out of the hole and exerts hydrostatic pressure which prevents an influx of formation fluids into the well bore. Shell estimates the maximum amount of hydrocarbons that could be released from an entire drilling season to be 128 lbs of VOC (Air Shell Beaufort Permit Application 01/18/10). Because of the low level of emissions, the proposed permit contains no conditions regarding this emission unit.

3.4.13 Shallow Gas Diverter System (FD-33)

The shallow gas diverter is an emergency protection device for the protection of the drill rig and personnel, and is not expected to be used except in the event of an influx to the well. The purpose of a diverter is to direct any formation fluids away from the rig in the event of an influx into the borehole. The diverter is used while drilling the shallow interval of the well before the blow out preventers are installed (the interval from the 30 inch casing shoe at approximately 500 feet, down to 20 inch casing shoe at approximately 1000 feet. The diverter does not shut the well in, but merely diverts the flow for discharge away from the rig, until the gas dissipates or the hole bridges over. The diverter is used because at the shallow depths, the formation strength is insufficient to withstand the potential pressure of a shut-in gas or gas/mud column in the annulus. The blow out preventers are installed after running the 20 inch casing, because below the 20 inch casing, the formation strength is sufficient to permit the well to be physically shut in using the blow out preventers.

According to Shell, these types of diverters have been in use for decades. For example, the model KFDS diverter, the type used on the Discoverer, has been in use for 25 years. MMS requires all rigs operating in OCS waters to use a diverter. Most offshore rigs have diverters whether or not they operate in OCS waters. Some land-based rigs use a diverter, or a similar device called a rotating head, if the geologic environment suggests the possibility of shallow gas.

The diverter is located in a housing located under the rig floor. The drilling riser is attached to the bottom of the diverter housing and maintains a continuous conduit for the return of the drilling fluids from the sea bottom back to the rig. The drill string is run through the rig floor and through the diverter housing and riser and down to the bottom of the well. The diverter housing has two large 16-20 inch diameter outlets oriented at 180 degrees to each other to which are attached large pneumatic fast acting valves. The control logic for these valves is such that only one can be closed at any given time. The diverter is a donut-shaped rubber element that is located in the diverter housing above the two outlets. A hydraulically activated piston compresses the element to seal around the drill string (or upon itself if the drill pipe is out of the hole) and direct the flow through the outlet whose valve is in the open position in the event of a shallow fluids (gas, water or air) flow. The opposing outlets permit the rig to divert the flow to the downwind side of the rig. Attached to the valves are large diameter flowlines that direct the flow from the diverter to the edge of the rig. The flowlines are generally horizontal, so that the elevation is approximately 5-15 feet below the rig floor.

Shell anticipates that the likelihood of encountering shallow gas in the planned drill sites is quite low, for the following reasons:

1. Shell has drilled wells nearby that have penetrated the same shallow formations and did not see shallow gas;
2. Shell has conducted shallow hazards seismic surveys to delineate possible shallow gas intervals and have selected locations to avoid any likely potential shallow gas sites;
3. Shell drills with a drilling fluid density that exceeds the anticipated formation fluid pressure;
4. Shell drills a smaller (12 ¼”-17 ½”) pilot hole and uses formation evaluation tools to interpret in real time the possibility of a shallow gas flow environment because drilling the smaller hole limits the amount of gas that can enter the well bore and permits the use of the dynamic kill procedure to shut off the flow; and
5. Shell will have a volume of heavy weight kill mud on hand immediately available to pump in the event of a formation fluid influx so that the appropriate hydrostatic head can be reestablished and influx can be shut off.

Based on the information above, EPA has determined that the very low probability of use of a diverter requires no permit conditions beyond requirements to record and report to EPA if a diversion event occurs. See Condition M.1.

3.4.14 Cuttings/Mud Disposal Barge (FD-34)

In an effort to avoid potential environmental impacts of the exploration program, Shell is considering collecting the drill cuttings and mud like materials and removing them from the area to a separate disposal site. Since there is no room on the Discoverer to store the material, Shell is considering the placement of an unpowered barge next to the Discoverer to be used as a repository for these materials. The barge itself would not emit air pollutants but would need to be delivered and removed from the site using a tug. The tug emission units have not been included in the emission inventory or modeling analysis. However, Shell has stated that the barge will be delivered before drilling begins and removed after drilling has ceased. The impacts from this activity should be similar to impacts from the anchor setting and retrieval activities which also occur before an after drilling.

If Shell utilizes a tug/barge combination, the requirements are contained in Condition N which prohibits any emissions from the barge and prohibits the tug from attaching to the Discoverer.

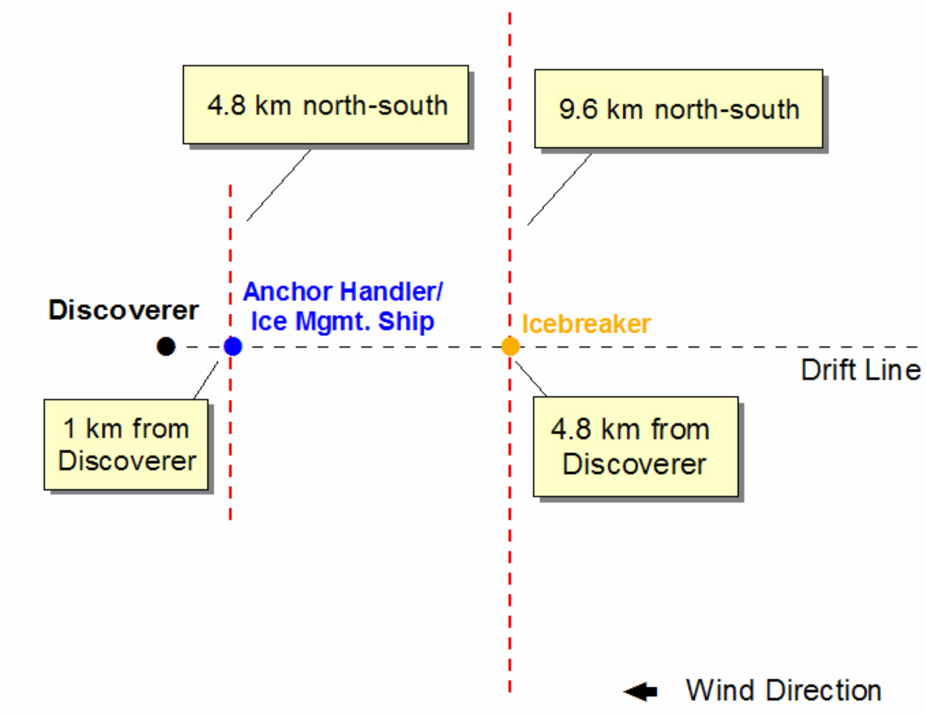
3.5 Ice Management and Anchor Handling Fleet

Shell's ice management and anchor handling fleet is expected to consist of two leased ships: an icebreaker (referred to in the permit as Icebreaker #1) and an anchor handler/icebreaker (referred to in the permit as Icebreaker #2). The purpose of this fleet is to manage the ice in the area of the Discoverer, which involves deflecting or in extreme cases breaking up any ice floes that could impact the ship when it is drilling, and to handle the ship's anchors during connection to and disconnection from the seabed.

The ice floe frequency and intensity is unpredictable and could range from no ice to ice sufficiently dense that the fleet has insufficient capacity and the Discoverer would need to disconnect from its anchors and move off site. Based on statistics on ice at the Sivulliq drill site in the Beaufort Sea, Shell estimates that ice breaking capability in its lease holdings in Lease Area lease sales 195 (March 2005) and 202 (April 2007) in the Beaufort Sea would only be required 38 percent of the time. For the remainder of the time the ice management and anchor handling fleet would be beyond the 25-mile radius from the Discoverer in a warm stack mode (anchored and occupied).

The primary driver of the ice floe is the wind, so the ice management ships are typically upwind of the Discoverer when managing the ice. Figure 3-1 depicts the approximate locations of the primary icebreaker and the anchor handler/ice management vessel when used to break one-year ice.

Figure 3-1: Ice Management and Anchor Handling Ships Locations for Breaking of One Year Ice



For addressing one-year ice, Icebreaker #1 will typically be positioned from 4,800 meters to 19,000 meters upwind on the drift line and Icebreaker #2 will be located from 1,000 meters to 9,600 meters upwind from the Discoverer. In the case of thick ice, the width of the Icebreaker #1 swath will be about 3 miles (4.8 kilometers) to either side of the drift line and Icebreaker #2 will be moving laterally 1.5 miles (2.4 kilometers) to either side of the drift line. The actual vessel distances will be determined by the ice floe speed, size, thickness, and character, and wind forecast. Although 2-meter-thick first-year ice is not expected, it might occur and the ice management fleet would be moving at near full speed to fragment this ice. Occasionally there may be multi-year ice ridges which are expected to be broken at a much slower speed than used for first-year ice. Multi-year ice may be broken by riding up onto the ice so that the weight of the icebreaker on top of the ice breaks it.

Shell will be leasing Icebreaker #1 from year to year. Consequently, the vessel used as Icebreaker #1 may change from year to year. In order to accommodate this uncertainty, Shell has requested that the permit allow for a generic Icebreaker #1. Furthermore, the fleet could consist of either two vessels or only one vessel, depending on availability of ships and ice conditions. At present, there are only a limited number of eligible ships. Murmansk Shipping of Russia operates one vessels – the Vladimir Ignatjuk. Viking leases four vessels – the Odin, the Tor, the Balder and the Vidor. The Talagy is available from Smit, and lastly, the Nordica and Fennica are operated by Finstaship.

The emission sources from all of these icebreaker class vessels consist of diesel engines for propulsion power, general purpose generators, boilers and incinerators. To accommodate the requested flexibility, Shell has developed a single generic equipment list for Icebreaker #1 that cannot be exceeded for any vessel. Table 3-3 shows the maximum aggregate ratings for each category of equipment for Icebreaker #1.

Table 3-3: Maximum Aggregate Rating of Emission Sources for Icebreaker #1

Description	Make and Model	Maximum Aggregate Rating
Propulsion Engines	Various	28,400 hp
Generator Engine(s)	Various	2,800 hp
Heat Boiler(s)	Various	10 MMBtu/hr
Incinerator	Various	154 lbs/hr

To execute Icebreaker #2 duties, Shell will use one of two vessels – either the Tor Viking or a new icebreaker being built to their specifications by Edison Chouest. Each of these vessels will be equipped with SCR on the main engines, which will result in a substantial reduction of NO_X. (Shell Beaufort Permit Application 01/18/10). The latter vessel has not been named yet but is referred to by the shipbuilder as Hull 247. Throughout this permit documentation, this vessel is also referred to as Hull 247, with the intent that all permit conditions for Icebreaker #2 continue to apply to the vessel, even once it has had its name changed from Hull 247 to its permanent name. Table 3-4 shows the maximum aggregate ratings for each category of equipment for Icebreaker #2.

Table 3-4: Maximum Aggregate Rating of Emission Sources for Icebreaker #2

Description	Make and Model	Maximum Aggregate Rating
Tor Viking		
Propulsion Engines	Various	17,660 hp
Generator Engine(s)	Various	2,336 hp
Heat Boiler(s)	Various	1.37 MMBtu/hr
Incinerator	Various	151 lbs/hr
Hull 247		
Propulsion Engines	Various	24,000 kW
Heat Boiler(s)	Various	4.00 MMBtu/hr
Incinerator	Various	151 lbs/hr

Marine propulsion engines, such as those used on the icebreakers, have a different emission profile than the more common engines found on board the Discoverer. The most cited reference on emissions from marine engines is a document published by Lloyds Register. However, a more recent publication compares emission factors from Lloyds with more recent emissions data from the Swedish Environmental Research Institute (Corbett 11/23/04). To ensure that the emissions factors used in the emission inventory for this project were adequately conservative, EPA compared these data with emissions data from AP-42 (see Reference Table 3 in Appendix A) and used the highest value for each pollutant.

In addition, Shell has requested limits on $PM_{2.5}$ of 40.2 lbs/hr and on PM_{10} of 45.8 lbs/hr (Shell Beaufort Permit Application 01/18/10) on Icebreaker #1, and 11.4 lbs/hr and 11.7 lbs/hr, respectively, for Icebreaker #2. The proposed permit requires candidate icebreakers to have their emission units tested prior to each drilling season. If a candidate vessel's uncontrolled emissions of $PM_{2.5}$ or PM_{10} are above these values, then the vessel cannot be used as either Icebreaker #1 or Icebreaker #2. Conditions O.1 and P.1 contain these equipment capacity and emission limits for the two icebreakers.

In calculating emissions from the emission sources on board the icebreakers, all sources, except the propulsion engines, were assumed to operate at 100 percent of rated capacity. The propulsion engines were represented at operating at no more than 80 percent of rated capacity. Consequently, these restrictions are imposed in Conditions O.2 and P.2.

Based on the emissions calculations and resultant modeling, Shell has determined a maximum usage for the icebreakers. The emissions, fuel and power output limits associated with this scenario are contained in Conditions O.3, O.4, O.5, O.6, P.3, P.4, P.5 and P.6. The fuel and power output limits in Condition O.5, O.6, P.5 and P.6 will also serve to limit emissions of the other pollutants, such as CO. The fuel limits on the icebreakers are based on Shell's estimate of its need for icebreaking capacity and ensure that emissions from the icebreakers will not exceed the modeled emissions scenarios.

Based on Shell's application, there is no scenario where either of the icebreakers is attached to the drillship, thereby becoming part of the OCS source.[11] Consequently, the permit contains Conditions O.8 and P.10 that prohibit such attachment. The permit does allow each icebreaker to approach near the Discoverer for purposes of transferring equipment and crew to and from the Discoverer. Otherwise, Condition O.7 requires Icebreaker #1 to, consistent with the modeling analysis, operate outside of a 4800 meter long cone centered on the centerline of the Discoverer. Similarly, Condition P.7 requires Icebreaker #2 to operate outside of a 1000 meter long cone centered on the centerline of the Discoverer, except during anchor handling operations (Condition P.8) and bow washing (Condition P.9). The air quality impact analysis was based on these operating scenarios and therefore the permit contains emission limits to impose these restrictions. The icebreakers are allowed to transit through their respective cones as these transit events will be of short duration and at low loads as they will not be conducting icebreaking activities within the cones. Modeled impacts from transit events in the area would therefore be expected to be lower than the worst case scenario.

In order to assure compliance with the emission limits, both icebreakers are required to test their emission sources each drilling season as provided in Conditions O.10 and P.12. Conditions O.11 and P13 require Shell to conduct monitoring, recordkeeping and reporting to assure compliance with the substantive conditions of Sections O and P of the permit.

[11] As discussed in Section 2.5.1 above, EPA does not consider Icebreaker #2 to be physicially attached to the Discoverer within the meaning of the definition of "OCS source" in 40 C.F.R. § 55.2 during the time it is assisting the Discoverer in the anchor setting and retrieval process.

3.5.1 Anchor Setting and Retrieval

As discussed above, the anchor-handling operation involves placing the Discoverer anchors on the seabed in preparation for drilling, and retrieving the anchors when the Discoverer is being moved off the well. Anchor handler propulsion power during anchor handing operations is either low or at idle since it is precision work setting anchors, spooling-out lines, and tensioning lines. The emissions from Icebreaker #2 during anchor retrieval are included in those allowed for Icebreaker #2 in Conditions P.3 and P.4.

3.5.2 Bow Washing of Discoverer

Occasionally, ice can build up at the bow of the Discoverer. Periodically, to remedy this situation, Icebreaker #2 will pass close to the Discoverer bow and dislodge this ice with its propeller wash. During these "bow washing" events, which would last no more than one hour, Icebreaker #2 operates at low power, and operates from either side of the bow (rather than in front of the bow).

3.6 Supply Ship/Barge and Tug

As described in Section 3.4.11, although the Discoverer is expected to be provisioned at the beginning of the season, additional supplies will be needed. These supplies will be brought out on a supply ship or barge and tug combination. Section 3.4.11 addressed operations and emissions while the supply ship or barge is attached to the Discoverer. This section addresses operations of the supply ship or barge and tug as it transits to and from the Discoverer. Table 3-5 lists the emission units associated with the supply ship.

Table 3-5: Supply Ship/Barge and Tug

Description	Make and Model	Maximum Aggregate Rating
Propulsion Engines	Various	7,200 hp
Generator Engine(s)	Various	584 hp

While the supply ship is in transit, Shell's application describes operations as consisting of the two propulsion engines operating at no more than 80 percent of rated capacity, and both generators operating at full load. Condition Q.1 prohibits operation of these engines at loads above 80 percent, and Condition Q.3.1 requires Shell to confirm operations of these engines. If a barge and tug is used in lieu of a supply ship, Condition Q.4 requires the barge and tug to comply with Conditions Q.1 through Q.3.

3.7 Oil Spill Response Fleet

The Oil Spill Response (OSR) fleet in the Beaufort is expected to consist of one offshore management/skimmer ship (Arctic Endeavor Barge/Point Barrow Tug), three Kvichak 34-foot work boats and one 47-foot skimmer (Rozema). Two of the three 34-foot work (Kvichak No. 1, No. 2,) boats will be used to tow containment booms while the third will act as a backup, for crew changes and re-fueling. It is possible that the Nanuq will be in the vicinity, but only as a berth for the OSR crew and occasional refueling of the Discoverer drilling equipment.

The OSR fleet is expected to be used only in the unplanned event of an oil discharge to the water. It will remain within about 5,000 meters of the drillship and downwind, but at least 2,000 meters away for safety purposes. The work boats and skimmer will remain on the deck of the management vessel and will only be in the water for training, drills, and response events. The OSR fleet will have on-water drills at a maximum frequency of once per day, which will consist of an 8-hour exercise. The exercise will normally consist of two 34-foot boats towing an open apex boom diverting a water stream back to the Arctic Endeavor Barge. The Arctic Endeavor Barge will have skimmers deployed and be simulating the recovery of oil downstream of the open apex. The Rozema Skimmer could also participate in the skimming exercise. During this exercise, the small craft as well as the Arctic Endeavor will be moving at approximately 0.5 nautical miles per hour.

In addition, a tanker will be stationed beyond 25 miles from the fleet. This tanker would store fuel to refuel the fleet and drill ship engines. It could also be used to potentially store oil and water from the Endeavor Barge as it becomes full from possible cleanup operations.

Table 3-6 presents the emission units on board the Point Barrow Tug, Arctic Endeavor Barge, Nanuq, Kvichak work boats and the Rozema Skimmer.

Table 3-6: Oil Spill Response Fleet

ID	Description	Make and Model	Rating
Offshore Management - Point Barrow Tug			
PBT-1 – 2	Propulsion Engines	Caterpillar 3512	1050 hp
PBT-3 – 4	Non-propulsion Generator Engines	Caterpillar 3304	150 hp
Skimmer Ship - Arctic Endeavor Barge			
AEB-1 – 4	Non-propulsion Generator Engines	Various	556 hp
Oil Spill Response Ship - Nanuq			
N-1 - 2	Propulsion Engines	Caterpillar 3608	2,710 kW
N-3 – 4	Non-propulsion Electrical Generators	Caterpillar 3508	1,285 hp
N-5	Emergency Generator	John Deere	166 kW
N-6	Incinerator	ASC/CP100	125 lbs/hr
Oil Spill Response Work Boat - Kvichak 34-foot No. 1			
K-1 – 2	Propulsion Engines	Cummins QSB	300 hp
K-3	Generator Engines	Various	12 hp
Oil Spill Response Work Boat - Kvichak 34-foot No. 2			
K-4 – 5	Propulsion Engines	Cummins QSB	300 hp
K-6	Generator Engines	Various	12 hp
Oil Spill Response Skimmer - Rozema 47-foot			

ID	Description	Make and Model	Rating
R-1 –2	Propulsion Engines	Various	700 hp
R-3	Generator Engines	N/A	9 hp

In determining the PTE from the OSR fleet, EPA relied on manufacturer's data for the two Caterpillar 3608 propulsion engines. Emissions from the two Caterpillar 3508 generator engines and the incinerator were estimated using EPA's AP-42 document. The emergency generator will not be used as part of normal operations and will only be used during a true emergency situation. Each of the two Kvichak work boats is equipped with two Cummins QSB engines for propulsion power and a small 12 hp generator engine. The Rozema Skimmer is equipped with two engines for propulsion and a small 9 hp generator engine. The Emissions for the former were based on manufacturer's data, while generator engine emissions were determined using AP-42.

Shell has committed to use of CDPF units from CleanAIR Systems on both the propulsion and non-propulsion generator engines on the Nanuq. Condition R.1 therefore requires use of the CDPF whenever these engines are operated. The main ambient air impacts from this fleet are annual NO_X. Accordingly, Condition R.2 imposes an annual NO_X emission limit that results from fuel usage limits requested by Shell. These fuel limits are contained in Condition R.3. Shell has analyzed operation of the OSR based on certain operational parameters for the fleet. Where these assumptions affect the outcome of the air quality impact analysis, adherence to these parameters is required in Conditions R.4, R.5 and R.6. These conditions require the OSR fleet to operate downwind of the Discoverer and at a minimum distance of 2,000 meters from the Discoverer except in the case of an emergency or to transfer equipment and crew to and from the Discoverer. In addition, the OSR fleet is prohibited from attaching to the Discoverer.

Condition R.7 requires Shell to stack test the propulsion engines and the generator engines for emissions of NO_X. Condition R.8 requires the use of fuel flow meters to track fuel usage for these emission units, and has other monitoring requirements to assure compliance with the other permit conditions in Section R of the permit.

3.8 Associated Growth

The indirect activities associated with the Discoverer exploration activities are likely to include support facilities in Deadhorse or Barrow. The facilities could include storage facilities and aircraft hangers. Shell has estimated emissions from operation of the warehouse as well as from helicopter access to the Discoverer (Shell Beaufort Permit Application 01/18/10). EPA agrees with Shell's conclusion that it is not anticipated that the project will result in a significant increase in air emissions associated with growth. Therefore EPA has determined that permit conditions are not necessary to address these types of activities.

4 BEST AVAILABLE CONTROL TECHNOLOGY

4.1 BACT Applicability and Introduction

Pursuant to 40 C.F.R. § 52.21(j), a new stationary source shall apply BACT for each pollutant subject to regulation under the CAA that it would have the PTE in significant amounts. Based on the emission inventory for the project presented in Table 2-1, NO_X, PM, $PM_{2.5}$, PM_{10}, VOC and CO will be emitted in quantities exceeding their respective significant emission rates. Therefore, BACT must be determined for each emission unit on the Discoverer which emits NO_X, PM, $PM_{2.5}$, PM_{10}, SO_2[12], VOC and CO while the drillship is operating as an OCS source.

BACT is defined in 40 C.F.R. §52.21(b)(12) in part as

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

The CAA contains a similar BACT definition, although the 1990 CAA amendments added “clean fuels” after “fuel cleaning or treatment” in the above definition. 42 U.S.C. § 7479(c).

On December 1, 1987, EPA issued a memorandum describing the top-down approach for determining BACT. In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps, for each pollutant to which BACT applies:

Step 1: Identify all control technologies.

Step 2: Evaluate technical feasibility of options from Step 1 and eliminate options that are technically infeasible based on physical, chemical and engineering principles.

[12] In addition to the SO_2 BACT requirement, Shell has committed to using ULSD in all emission units in the Associated Fleet to keep the H_2SO_4 PTE below the significant emission rate. Without the BACT requirement to use ULSD in all emission units on the Discoverer, the SO_2 PTE would be above the significant emission rate so PSD requirements still apply to SO_2 emissions from the Discoverer and Associated Fleet. See Sections 2.5.2and 2.5.3.

Step 3: Rank the remaining control technologies from Step 2 by control effectiveness, in terms of emission reduction potential.

Step 4: Evaluate the most effective controls from Step 3, considering economic, environmental and energy impacts of each control option. If the top option is not selected, evaluate the next most effective control option.

Step 5: Select BACT (the most effective option from Step 4 not rejected).

In the permit application, Shell applied the EPA top-down BACT methodology to groups of similar emission units on the Discoverer. For example, there are six large diesel generators (FD-1 to FD-6) that are identical and three diesel engine driven compressors that are identical (FD-9 to FD-11), so the BACT analysis was performed for each group of identical engines. Likewise, there are a number of smaller diesel engines [<500 horsepower (hp)] which are similar so that the BACT analysis can be performed for each similar group of emission units. EPA agrees that grouping identical or similar emission units for the BACT analysis is reasonable. EPA's BACT evaluation uses the top-down format and follows a pattern of grouping identical or similar emission units as was done in the Shell Beaufort Permit Application.

Throughout the BACT section PM, $PM_{2.5}$ and PM_{10} emissions will be addressed together for all emission units except the incinerator since it is assumed that essentially all of the PM and PM_{10} emissions are also $PM_{2.5}$ emissions, and the control technologies available for $PM_{2.5}$ emissions on the types of equipment aboard the Discoverer will also effectively control PM and PM_{10}. In addition, the BACT analyses for VOC and CO are grouped together because the same control technology is generally used to control both pollutants for the specific types of emission units on the Discoverer.

4.2 SO_2 BACT Analysis for the Diesel IC engines, Boilers and Incinerator

Step 1 – Identify all available control technologies

Most of the SO_2 emissions for this project result from combustion of diesel fuel which contains some amount of sulfur. Sulfur contained in the material burned in the incinerator also contributes to the SO_2 emissions. The available SO_2 control technologies can be grouped into one of two categories: use of low sulfur fuels and post-combustion treatment of the exhaust gases from the emission units. Shell searched the EPA RACT, BACT, LEAR Clearinghouse (RBLC) and the California BACT Clearinghouse (CA-BACT) for determinations made for SO_2 from the type of emission units on the Discoverer (diesel IC engines, small boilers and the incinerator). The search results are shown in Table 4-5 of the permit application (Shell Beaufort Permit Application 01/18/10). The most common control technologies found were "no control" or use of "low sulfur fuel." The only post-combustion SO_2 control technology found was a semi-dry scrubber for an incinerator which was much larger than the incinerator on the Discoverer. The RBLC and CA-BACT did not have any post-combustion control technology applications for diesel IC engines, small boilers, or small incinerators. Several other SO_2 flue gas desulfurization control technologies exist and are used on larger SO_2 sources, such as power plants, petroleum refineries, pulp mills and incinerators, but are not found in practice on smaller emission units such as the boilers and incinerator on the Discoverer.

Step 2 – Eliminate technically infeasible control options

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For technical reasons, EPA believes that post-combustion SO_2 control technologies are not feasible for any of the emission units on the Discoverer, all of which are relatively small emission units. The fact that no post-combustion controls were found in the RBLC search for diesel IC engines, small boilers, and small incinerators indicates that such controls they have not been found to be technically feasible or cost effective for small emission units in past determinations. Moreover, in this case, the emission units are located on a ship with limited space, and the ship will be located in an Arctic environment (low temperatures and limited fresh water availability). Use of ULSD fuel (discussed below) results in very low SO_2 emission rates (the table titled "Summary of Annual Emissions" for the Frontier Discoverer Sources in Appendix A, Shell Beaufort Permit Application 01/18/10, page A-1 shows less than 0.4 ton per year of SO_2 for the sum of all emission units on the Frontier Discoverer). Even if post-combustion SO_2 controls could be engineered to overcome the factors described above, they could not achieve the same degree of SO_2 emissions reduction as the use of ULSD fuel when compared to the use of a higher sulfur baseline fuel. Therefore, the BACT analysis for SO_2 is focused on evaluating diesel fuels with various levels of sulfur content.

Step 3 – Rank the remaining technologies by control effectiveness

Shell identified diesel fuels with three different sulfur contents, including ULSD with ≤0.0015 weight percent sulfur (≤15 ppm), low sulfur diesel ≤0.05 weight percent sulfur (≤500 ppm) and higher sulfur diesel fuel (>500 ppm). Since the SO_2 emissions are directly proportional to the sulfur content of the fuel, the fuels are rank ordered in SO_2 reduction effectiveness from the fuel with the lowest amount of sulfur to the fuel with the highest amount of sulfur.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Shell proposed to use the lowest available sulfur content diesel fuel with a sulfur content of ≤15 ppm. ULSD fuel is required by other EPA regulations for both on-road diesel vehicles and for non-road diesel engines. Therefore, ULSD fuel is available as a control technology for the emissions units on the Discover. Not only does ULSD result in the lowest SO_2 emissions, it is necessary to allow the use of various catalytic control devices for other pollutants such as selective catalytic reduction for NO_X control, oxidation catalysts and catalytic diesel particulate filters for particulate matter, VOC and CO control (discussed in the sections below).

Use of ≤15 ppm ULSD for the emission units on the Discoverer provides a greater than 97 percent reduction in SO_2 emissions compared to low sulfur diesel (≤500 ppm). As mentioned above, using ULSD fuel, the total annual emissions of SO_2 from all the emission units on the Discoverer are less than one ton per year. Because Shell proposed the most effective control option as BACT and there is no evidence that the most effective control option would have adverse environmental impacts, no additional evaluation is required.

Step 5 – Select SO_2 BACT for the Diesel Engines, Boilers and Incinerator

Since use of ULSD fuel is the most effective control option, EPA is proposing that BACT for SO_2 is the use of ULSD fuel with ≤0.0015 weight percent sulfur (≤15 ppm) for the emission units located on the Discoverer. The fuel sampling and test methods for determining the sulfur content of the diesel fuel are presented in Section 4.8

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4.3 NO_X BACT Analysis

Step 1 – Identify all available control technologies

In general, NO_X emissions are generated in the combustion process as a result of the reaction of oxygen with nitrogen contained in the fuel or with nitrogen present in the combustion air. As described in Section 4.2, we have determined that BACT for SO_2 is the use of ULSD fuel in all combustion sources on the Discoverer. The processes used by the petroleum refining industry to produce ULSD fuel, such as hydrotreating and hydrocracking, remove nitrogen as well as sulfur. Since ULSD fuel contains very little nitrogen, most of the NO_X emissions from the emissions units on the Discoverer are attributable to the reaction of oxygen with nitrogen in the combustion air, known as thermal NO_X. The concentration of thermal NO_X formed is a function of the combustion temperature with higher temperatures resulting in higher concentrations of NO_X in the exhaust gas.

Shell searched the EPA RBLC and the CA-BACT for thermal NO_X determinations made for diesel IC engines >500 hp, diesel IC engines <500 hp, small boilers and the incinerator. Their findings are summarized in Table 4-2 of the permit application. For diesel IC engines, the control technologies include combustion modifications designed to lower the combustion temperature and thereby lower the generation rate of NO_X. These combustion modification technologies include injection timing retard (ITR), intake air cooling (AC), high injection pressure for the fuel (HIP) and water injection (WI). Although not listed in the RBLC or CA-BACT, Shell also identified exhaust gas recirculation (EGR) as another diesel IC engine control technology for NO_X that has become commercially available. The RBLC also lists low NO_X design (LND) for several engines, but does not describe the actual NO_X combustion control technology. Presumably the determinations labeled LND are referring to specific combustion chamber designs or other engine modifications that reduce NO_X formation and, thus, these designs are intrinsic to the particular model of engine associated with each RBLC determination for LND. Another engine modification control alternative is a cam shaft cylinder reengineering kit which is available for certain diesel engines.

Some of the combustion modification technologies for NO_X control have associated negative impacts. For example, ITR results in increased emissions of particulate matter, VOC and CO, decreased fuel efficiency and higher soot contamination of the engine lube oil. The use of combustion modification technologies can result in NO_X emission reductions ranging from 10 percent to 50 percent from baseline emissions depending on the specific technology or combination of technologies (Shell Beaufort Permit Application 01/18/10, page 53; EPA 09/28/07 Retrofit Strategies; EPA 1995 AP-42 and updates; MassDEP 1/08).

In 1998 EPA set new emission standards for nonroad diesel engines. The rulemaking was part of a 3-tiered progression to lower emission standards. Each tier involves a phase in by horsepower rating over several years. Tier 1 standards for engines over 50 horsepower were phased in from 1996 to 2000. More stringent Tier 2 standards for all engine sizes were phased in from 2001 to 2006, and yet more stringent Tier 3 standards for engines rated over 50 horsepower were phased in from 2006 to 2008 (EPA 08/98 Nonroad Diesel). Depending on the year of manufacture, new diesel IC engines are available that meet the EPA Tier 2 or Tier 3 emission standards. The resulting lower NO_X emission rates for diesel IC engines designed to meet the Tier 2 or Tier 3 standards are the result of the intrinsic engine design features built into them by the manufacturer.

The only post-combustion exhaust gas treatment for NO_X emissions found by the search of the RBLC and CA-BACT for diesel IC engines was selective catalytic reduction (SCR). SCR involves reaction of a reagent such as urea or ammonia with NO_X in the presence of a catalyst to yield elemental nitrogen. SCR systems have the capability of reducing NO_X emissions by 90 percent or more. Use of selective non-catalytic reduction (SNCR) has been investigated for controlling NO_X from diesel IC engines. However, because the NO_X reduction reactions are highly dependent on temperature, the NO_X reduction potential of SNCR is much lower than for SCR, and SNCR is not suited for diesel engine applications with low exhaust temperatures (Nam 2/13/02; WRAP 11/28/05).

In the BACT analysis, Shell included two additional post-combustion control options for NO_X: Lean NO_X Catalyst (LNC) also know as Hydrocarbon SCR (HC SCR) and NO_X Adsorber technology. LNC or HC SCR utilize a NO_X reduction catalyst and uses unburned hydrocarbons in the exhaust stream or additional diesel fuel that is injected into the LNC device as the reducing agent to react NO_X to elemental nitrogen. LNC is usually integrated with a catalytic diesel particulate filter (discussed further in Section 4.4) to remove excess hydrocarbons by catalytic reaction to carbon dioxide and water. One manufacture of a LNC system is Clēaire whose LONESTAR™ system for off-road applications is designed to achieve at least 40 percent NO_X reduction (Clēaire 2009). The California Air Resources Board has verified the Clēaire LONESTAR™ system for certain turbo charged diesel engines but excludes 2-stroke engines, engines with original equipment manufacturers diesel particulate filters and engines with external EGR. NO_X Adsorbers adsorb NO_X by catalytically reacting NO to NO_2 and reacting the NO_2 with a chemical coating on the catalyst matrix to form a nitrate salt. Before the chemical coating becomes saturated, it must be regenerated using a chemical such as hydrogen.

The search of the EPA RBLC and the CA-BACT for boilers and incinerators found determinations based on the use of low NO_X burners (LNB), EGR and SNCR.

Good combustion practice of operating and maintaining the emission units according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions is also an available work practice for all emission units on the Discoverer.

As discussed above, the control option must result in an emission rate no less stringent than an applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. 40 C.F.R. § 52.21(b)(12)(definition of BACT).

4.3.1 NO_X BACT for the Generator Diesel IC Engines (FD-1 to FD-6)

Step 2 – Eliminate technically infeasible control options

Six Caterpillar D399 generator sets provide the electrical power for drilling and ship utilities on the Discoverer (FD-1 to FD-6). Each of these generator diesel IC engines is rated at 1325 hp, and the normal procedure is to operate the minimum number of engines needed to power the load while keeping each operating engine at 50 percent capacity or greater. Since the generator diesel IC engines are the largest engines on the Discoverer and will operate for the most hours, thereby resulting in the largest potential uncontrolled emissions, BACT for the generator diesel IC engines was evaluated separately from BACT for the other diesel IC engines.

The available controls for the generator diesel IC engines include ITR, AC, HIP, LND, Tier 2 or 3 controls, WI, EGR, and SCR. EPA's view is that LND, Tier 2 or 3 controls, EGR, and WI are technically infeasible. LND and Tier 2 or 3 level controls are intrinsic to the original engine design and are not part of the Caterpillar D399 design. EGR is not available for older model engines such as the Caterpillar D399. WI is considered technically infeasible for a number of reasons, the most significant being the large amount of extremely pure water required. In general, reduction of NO_X emissions by one percent requires one percent of water in the water-fuel system. In other words, achieving a 50 percent NO_X reduction requires running the engine using a 1:1 mix of water and diesel fuel. A WI system would require water purification equipment and storage capacity on a ship with limited space availability. Another issue with the introduction of water in the combustion chamber is the potential for liquid water droplets to contact the cylinder surface, which would cause an immediate disintegration of the lubrication oil film and damage to the engine. Cold temperature environments (such as the Arctic Ocean) are also problematic for WI systems due to the potential for freezing. For these reasons and because of the potential engine retrofit incompatibility for the Caterpillar D399 engines, EPA believes that WI is technically infeasible for these engines.

ITR, AC, and HIP and good combustion practice are technically feasible for this generator engine model. SCR is technically feasible because the engines are stationary on the vessel deck and there is adequate room to install the SCR devices.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for the Discoverer's generator diesel IC engines (FD-1 to FD-6) are ranked by control effectiveness as follows:

1. SCR – 90 percent control (0.5 g/kW-hr NO_X)
2. ITR, AC, and/or HIP – 10 percent to 50 percent control
3. Good combustion practices

In the permit application, Shell provided several uncontrolled NO_X emission rates for the Caterpillar D399 generator engines, including actual stack test information for one of the Caterpillar D399 generator engines (FD-1) (TRC 06/03/07). Testing was performed by TRC Environmental Corporation on May 18 and 19, 2007 for three engine load conditions (100 percent, 75 percent and 50 percent). The measured NO_X emission rate ranged from 5.62 g/kW-hr to 6.99 g/kW-hr, with the lowest emission rate at 100 percent load. Using the lowest measured uncontrolled emission rate of 5.62 g/kW-hr and applying the proposed and guaranteed emission rate of 0.5 g/kW-hr, the percentage reduction in NO_X emissions from applying SCR is >91 percent. The percentage reduction from the higher uncontrolled emission rates would be even greater.

EPA has promulgated emission standards for non-road diesel IC engines in 40 C.F.R. § 89.112. For engines ≥750 hp, the Tier 2 emission limit for NO_X + non-methane hydrocarbons (NMHC) is 6.4 g/kW-hr. EPA also promulgated emission standards for new and in-use non-road compression-ignition engines in 40 C.F.R. § 1039. Although these standards for engines ≥750 hp do not apply until model year 2011, the NO_X emission standard for generator sets is 0.67 g/kW-hr. By comparison with these standards, the NO_X emission limit of 0.5 g/kW-hr that EPA is proposing in this permit for the generator diesel IC engines is significantly lower.

Recent permitting actions for IC engines by the Alaska Department of Environmental Conservation have not required NO_X emission limits nearly as low as the 0.5 g/kW-hr emission limit proposed for the Discoverer generator IC engines. For example, the permit for the Nixon Fork Mine issued August 13, 2009 included a generator engine operating at 11.1 g/kW-hr; the

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permit for the Naknek Power Plant issued March 31, 2009 included a generator engine with an emission rate of 26.0 g/kW-hr; and the Liberty Oil Project (BP) permit issued December 12, 2008 included a generator engine with an emission rate of 6.3 g/kW-hr.

Based on achieving the proposed NO_X emissions limit 0.5 g/kW-hr, the maximum NO_X emissions from each Caterpillar D399 generator engine on the Discoverer would be 1.55 tpy as shown in Appendix A. The maximum total NO_X emissions from all six generator engines would be 9.30 tpy.

EPA asked Shell to evaluate the use of diesel IC engine modifications such as ITR, AC or HIP in combination with the SCR control system, since theoretically a lower inlet NO_X concentration to the SCR control system would result in a lower outlet value (EPA 04/08/09). In an email to EPA dated April 20, 2009, Shell's environmental consultant provided a response from D.E.C. Marine (Air Sciences 04/20/09). D.E.C. Marine stated that, although the use of engine modifications in addition to the SCR control system would, in theory, result in a lower NO_X emission rate, the engine modifications would have collateral adverse impacts, including increased fuel consumption, lower exhaust gas temperature and increased levels of particulate and hydrocarbon emissions. The surface of the catalyst in the SCR (and the oxidation catalyst) systems would be adversely affected by the higher loading of particulate matter and hydrocarbon emissions and the lower exhaust temperature would reduce the effectiveness of the catalytic reactions in the SCR system. D.E.C. Marine stated that "It is therefore best to optimize the engine for good combustion …….and keeping the temperatures high." D.E.C. Marine also stated that use of the SCR system is a much more effective way to reduce NO_X emissions than using retrofit engine modifications, and that the SCR system is designed with "plenty of margin to make sure we will stay below the guaranteed level of 0.5 g/kW-hr…." EPA agrees that optimizing the engine combustion performance in combination with the SCR control system is a preferred strategy for controlling NO_X from the generator engines.

The use of SCR results in low concentrations of ammonia emissions that are not completely reacted in the SCR system. The unreacted ammonia emissions are also known as ammonia slip. In order to ensure that the ammonia slip is maintained at the minimum level commensurate with achieving the NO_X emission limit of 0.5 g/kW-hr, EPA is proposing an emission limit for ammonia as part of the BACT emission limit for NO_X from the generator engines. D.E.C. Marine stated that the SCR system is designed so that ammonia slip is less than 10 ppm; however, they expect that the ammonia slip will actually be less than 3 ppm because the oxidation catalyst that follows the SCR catalyst will oxidize most of the ammonia that passes through the SCR catalyst (Shell Beaufort Permit Application 01/18/10, page 21). Based on these facts, EPA believes that an ammonia emission limit representative of good performance for the SCR and oxidation catalyst system is 5 ppm at the actual stack gas conditions.

<u>Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts</u>

Shell proposed that SCR represents BACT for the generator diesel IC engines because it offers the highest NO_X emissions reduction of ≥90 percent. Shell requested a technical proposal for an SCR control system from D.E.C. Marine, a Swedish company that has been installing such control systems on marine vessels since 1991. According to a letter from D.E.C. Marine to Shell dated 2008-10-09 (Shell Beaufort Permit Application 01/18/10, Appendix C), D.E.C. Marine has installed SCR control systems on more than 70 vessels since 1991. The SCR system that D.E.C. Marine proposed is capable of reducing NO_X emissions to as low as 0.1 g/kW-hr under ideal steady state conditions; however, the D.E.C. Marine guarantee is 0.5 g/kW-hr because of the continually varying operating level of the engines and the severe environmental conditions in the Arctic Ocean.

As discussed in more detail in Step 3 above, EPA believes that an emission limit of 0.5 g/kW-hr, in conjunction with good combustion practice and a limit on ammonia slip, represent BACT for the generator diesel IC engines. The D.E.C. Marine SCR system uses a tuned urea injection system where the rate of urea injection is a function of engine operating load. In addition, the system includes a NO_X exhaust analyzer that sequences through the six generator engines to provide a direct measurement of NO_X emissions once per hour for each engine. The information from the NO_X analyzer provides a means for the urea injection algorithm to be optimized over time. Since the NO_X analyzer is not used for instantaneous continuous control of the urea injection system, periodic monitoring of NO_X is appropriate. Use of a continuous NO_X analyzer on each engine would not provide any significant benefit, but would increase the analyzer maintenance requirements and monitoring costs by a factor of six.

Step 5 – Select NO_X BACT for the generator diesel IC engines

Based on the facts presented above, EPA is proposing a NO_X emission limit of 0.50 g/kW-hr, in conjunction with an ammonia emission limit of 5 ppm at actual stack gas conditions, as BACT for the Caterpillar D399 generator diesel IC engines based on the use of SCR technology. The averaging time and compliance test methods for these emission limits (and the emission limits discussed below) are presented in Section 4.8.

4.3.2 NO_X BACT for the Compressor Diesel IC Engines (FD-9 to FD-11)

Step 2 – Eliminate technically infeasible control options

As discussed in Section 4.3, the available control technologies for the Discoverer's three MLC compressor diesel IC engines (FD-9 to FD-11, 540 hp Caterpillar C-15 engines) are ITR, AC, HIP, LND, Tier 2 or Tier 3 controls, WI, EGR, NO_X adsorbers, LNC and SCR. The Caterpillar C-15 diesel engines for the air compressors are new Tier 3 engines which incorporate the technologies of EGR and AC into the intrinsic design of the engines to meet the Tier 3 emission standard of 4.0 g/kW-hr for NO_X + NMHC. Because these engines are designed and tuned to meet Tier 3 standards, they are incompatible with incorporating combustion control technologies such as ITR, AC, HIP, LND, and EGR in addition to the Tier 3 controls. EPA believes that WI is technically infeasible due to the cold climate in which these generators will be operated, the potential engine retrofit incompatibility, the excessive pure water requirements, limited available space on the ship for storing the water, and the potential risk of engine damage associated with this technology.

NO_X adsorbers have been used on light duty vehicles; however, Shell stated that they are not aware of any marine applications of this technology. Shell cites one manufacturer, Johnson Matthey, as stating that they are just starting to look at this technology for stationary applications and the technology is not commercially available for stationary applications (Shell Beaufort Permit Application 01/18/10, page 73). EPA's Office of Transportation and Air Quality has published a summary of potential retrofit technologies for diesel engines which includes NO_X adsorbers (EPA 12/14/09 Potential Retrofit Technologies). However, NO_X adsorbers are not listed on EPA Verified Retrofit Technologies list nor are they listed on the EPA Verified Nonroad Engine Retrofit Technologies List (EPA 12/14/09 Verified Retrofit Technologies; EPA

12/14/09 Nonroad Retrofit Technologies). Since NO_X adsorber technology is not commercially available, EPA considers this technology to be technically infeasible for this application.

LNC has been used in retrofit applications for both on-road and nonroad diesel engines. Example applications include backhoes, graders, loaders and back-up generators; however, neither Shell nor EPA is aware of any marine applications of LNC. A representative of Clēaire, a vendor of LNC technology, stated that there have been few stationary applications of their LNC systems; and although there are no technical reasons the LNC systems would not work, the Clēaire representative stated that their LNC technology would be more of a demonstration project for this application and technical support during the demonstration of this technology would be needed. Therefore, the Clēaire representative would not recommend their LNC technology as commercial for this application (Shell Beaufort Permit Application 01/18/10, page 73). EPA considers this technology to be technically infeasible for this application.

The compressor diesel IC engines are portable due to critically limited deck space on the Discoverer. The compressor units are designed to be portable so they can be removed from the drill ship at any time should deck space be required for other equipment or materials. However, for operational reasons the preference is to have the compressor units on board the drill ship to minimize the time required to set up the units for a second MLC operation if so required. The physical location of the compressor units on the Discoverer is shown in the photograph labeled Figure 1 of the February 4, 2010 supplement to the BACT analysis (Environ 02/04/10). As can be seen in the photograph, there is very limited space around the compressor units. Shell provided drawings of the SCR and SCR injection control unit sized for the compressor IC engine. The SCR catalyst unit is approximately 30 inches square and 52 inches flange to flange. Additional space would be required for the piping to connect the SCR catalyst unit to the exhaust pipe from the engine. In addition, the SCR injection control unit has a footprint of about 40 inches by 18 inches and a height of approximately 66 inches. The supply of urea for an SCR system for the compressor engines would require a 1000 gallon storage tank with a deck space requirement of approximately 6.5 by 4 feet and would need to be maintained at a temperature above the "salt out temperature" when urea begins to precipitate from solution. Shell contends that there is not adequate space to install the SCR equipment at the location of the compressor units on the Discoverer and that SCR should therefore be considered technically infeasible for this application.

The State of California typically imposes emission controls that are more stringent than the Federal standards. The California Air Resources Board has created a voluntary Portable Engine Registration Program (PERP), which allows owners and operators to register their portable engines/equipment and operate them throughout the state without obtaining permits from local air districts. The current registration requirements for 2009 and 2010 for engines between 75 and 750 bhp are that these engines must meet the Tier 3 standards. Local air districts in California use the PERP when permitting portable engines including skid mounted engines used on offshore platforms and drilling operations. For example, the Santa Barbara County Air Pollution Control District, which has offshore platforms in its jurisdiction, considers engines meeting the PERP requirements to also meet BACT requirements and does not require additional controls for these engines (Shell Beaufort Permit Application 01/18/10, pages 68-69). Portable engines such as the compressor IC engines which meet the Tier 3 standards would meet BACT requirement without additional controls under the PERP.

For the reasons discussed above, EPA believes that SCR is not technically feasible for portable deck engines and has excluded SCR from further consideration in the BACT analysis for the compressor diesel IC engines.[13]

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for compressor diesel IC engines (FD-9 to FD-11) are ranked by control effectiveness as follows:

1. Tier 3 Emission Standards of 4.0 g/kWh of NO_X + NMHC
2. Tier 2 Emission Standards of 6.4 g/kWh of NO_X + NMHC

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since Shell proposed the most effective control option (the Tier 3 emission standards) as BACT and there is no evidence that the most effective control option would have adverse environmental impacts as compared to other control options, no additional evaluation is required.

Step 5 – Select NO_X BACT for the compressor diesel IC engines

Based on the facts presented above, EPA is proposing that BACT for NO_X from the compressor diesel IC engines is 4.0 g/kW-hr NO_X + NMHC, the Tier 3 engine standard.

4.3.3 NO_X BACT for the Smaller Diesel IC Engines (FD-12 to FD-20)

Step 2 – Eliminate technically infeasible control options

The smaller diesel engines on the Discoverer include:

1. FD-12 and FD-13, HPU Engines – 250 hp Detroit 8V-71
2. FD-14 and FD-15, Cranes – 365 hp Caterpillar D343
3. FD-16 and FD-17, Cementing Units – 335 hp Detroit 8V-71N
4. FD-18, Cementing Unit – 147 hp GM 3-71
5. FD-19, Logging Unit Winch – 250 hp Caterpillar C7
6. FD-20, Logging Unit Generator – 35 hp John Deere PE4020TF270D

The available control technologies for engines under 500 hp are ITR, AC, LND, WI, cam shaft reengineering kit, LNC, NO_X adsorbers, SCR and good combustion practices. The Logging Unit Winch engine (FD-19) has been up-graded from the engine proposed in the original permit application to an engine (Caterpillar C7) that meets the Tier 3 engine standards. The logging unit generator engine was also changed to a John Deere engine that meets the Tier 2 engine standards.

[13] Although we have determinated this technology is not technically feasible, even if it were feasible and remained in the analysis, it would be excluded from consideration in step 4 due to unreasonable control costs. Shell submitted for a cost effectiveness analysis for SCR based on cost quotation data from Johnson Matthey, a SCR vendor, in the December 2009 supplement to the BACT analysis (Environ 12/11/09). The cost effectiveness value calculated for the compressor engines was greater than \$34,000/ton of NO_x removed, which is greater than what EPA considers reasonable for a BACT determination.

As explained in Section 4.3.1, WI is considered technically infeasible due to the cold climate in which these generators will be operated, the potential engine retrofit incompatibility, the excessive pure water requirements, limited available space on the ship for storing the water, and the potential risk of engine damage associated with this technology.

ITR and AC decrease the peak combustion temperature, which lowers the NO_X generation rate but can increase the exhaust gas temperature, which may in turn adversely impact exhaust valve life and turbocharger performance. The Tier 2 and Tier 3 engines are not amenable to ITR or AC because these engines have been optimized as part of the low NO_X design of the engines. ITR is not as effective on engines which lack electronic fuel injection such as the HPU units, the cementing units, and the cranes. ITR and AC result in an increase in emissions of PM, CO and VOC emissions which puts an additional load on the downstream control equipment for those pollutants which is detrimental to the performance of the downstream control equipment. For these reasons EPA considers ITR and AC to be infeasible technology for any of the smaller diesel IC engines on the Discoverer.

EGR is not feasible for retrofit on the HPU units and the cementing units because these engines are older two-stroke engines which are not amenable to EGR. The crane engines are older Caterpillar engines for which EGR is not available. The logging unit engines are newer Tier 2 and Tier 3 engines which incorporate EGR in the low NO_X design of the engines. Therefore, EGR is considered technically infeasible for any of the smaller IC diesel engines on the Discoverer.

Cam shaft cylinder reengineering kits are available from Clean Cam Technology Systems (CCTS) for older Detroit Diesel Corporation two-stroke engines such as the HPU engines and the two larger Cementing unit engines. The CCTS retrofit kits are not available for the older Caterpillar engines or the newer Logging unit engines. The CCTS retrofit kits are considered technically feasible only for the HPU engines (FD-12 and FD-13) and the two larger Cementing unit engines (FD-16 and FD-17).

NO_X adsorbers have been used on light duty vehicles; however, Shell stated that they are not aware of any marine applications of this technology. Shell cites one manufacturer, Johnson Matthey as stating that they are just starting to look at this technology for stationary applications and the technology is not commercially available for stationary applications (Shell Beaufort Permit Application 01/18/10, page 73). EPA's Office of Transportation and Air Quality has published a summary of potential retrofit technologies for diesel engines which includes NO_X adsorbers (EPA 12/14/09 Potential Retrofit Technologies). However, NO_X adsorbers are not listed on EPA Verified Retrofit Technologies list nor are they listed on the EPA Verified Nonroad Engine Retrofit Technologies List (EPA 12/14/09 Verified Retrofit Technologies; EPA 12/14/09 Nonroad Retrofit Technologies). Since NO_X adsorber technology is not commercially available, EPA considers this technology to be technically infeasible for this application.

LNC has been used in retrofit applications for both on-road and nonroad diesel engines. Example applications include backhoes, graders, loaders and back-up generators; however, neither Shell nor EPA is aware of any marine applications of LNC. A representative of Clēaire, a vendor of LNC technology, stated that there have been few stationary applications of their LNC systems; and although there are no technical reasons the LNC systems would not work, the Clēaire representative stated that their LNC technology would be more of a demonstration project for this application and technical support during the demonstration of this technology would be needed. Therefore, the Clēaire representative would not recommend their LNC

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technology as commercial for this application (Shell Beaufort Permit Application 01/18/10, page 73).

There are no determinations for installing SCR on diesel engines under 500 hp in the EPA RBLC or CA-BACT, indicating that SCR has not previously been deemed BACT for this diesel engine category due to technical infeasibility and/or energy, environmental, and/or economic impacts. Although SCR is proposed for the main generator sets, several issues have been identified with applying SCR to the smaller IC engines. Whereas the generator engines will be operated in a manner and in a location where the exhaust temperature going to the SCR can be maintained in the appropriate range and the urea temperature will be above the "salt out temperature," the smaller engines will operate on a more intermittent basis over a wide range of loads in locations more exposed to ambient temperature conditions. The following considerations have an impact on the technical feasibility of SCR for the smaller IC engines.

1. The dynamic loading of the smaller engines with short term load swings up to 50 percent can be expected when these engines are operated. The changing load will result in times when the engine load is not sufficient to achieve the exhaust temperatures necessary for optimal performance of the SCR system. Below about 400ºF the NO_X reduction may be as low as 20 percent. Excessive ammonia slip can occur when the catalyst temperature is not in the optimum range for the reaction between NO_X and ammonia.
2. The smaller engines are located on the topside deck of the ship and exposed to the ambient climatic conditions in the Arctic which will contribute to the difficulty of maintaining proper temperature in the SCR catalyst. The photos in the February 4, 2010 supplement to the BACT analysis shows several of the smaller engine units in Figures 1 through 6 (Environ 02/04/10).
3. Urea will "salt out" or precipitate from solution at lower temperatures depending on the concentration of urea in the solution. Whether the urea is stored in local tanks at each engine or transferred from a central storage tank, special precautions would be required to ensure that urea did not precipitate.
4. Space on the ship is limited as shown in Figures 1 to 5 of the February 4, 2010 supplement to the BACT analysis. Several of the smaller engines are "packaged" into enclosed skids which have little or no additional space to accommodate SCR equipment and urea storage tanks without a total redesign of the units.
5. Shell has expressed concern that taking additional deck space for SCR equipment or for urea storage tanks would compromise the maneuverability of equipment needed during drilling.

For these reasons, EPA believes SCR is technically infeasible for implementation on the smaller diesel IC engines on the Discoverer.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for the smaller diesel IC engines (FD-12 to FD-20) are ranked by control effectiveness as follows:

1. Cam shaft cylinder reengineering kits
2. Good combustion practice

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

The cost of the CCTS engine retrofit cam kits varies by size of the engine, but is relatively low. However, the cost of the kits is not the major cost of the engine rebuild. The major costs are associated with providing the technicians and mechanics to the site to extract the engine and shipping the engine to and from the Discoverer and the engine shop where the retrofit kit is installed. The cost of the kit ranges from \$4000 to \$7500 depending on engine size. The additional cost for logistics and shipping was estimated by Shell to be \$50,000 per engine. Shell estimated the cost effectiveness for the reengineered HPU engines to be \$16,202/ton of NO_X reduced and \$12, 206/ton of NO_X reduced for the reengineered Cementing units (Shell Beaufort Permit Application 01/18/10, page 75). EPA believes that these cost effectiveness values exceed what is reasonable to be representative of BACT for these engines.

The remaining technically feasible control option is the use of good combustion practice. Good combustion practice for NO_X control essentially consists of operating and maintaining the engines according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

Step 5 – Select NO_X BACT for the smaller combustion engines

EPA proposes that BACT for NO_X for all of the smaller diesel IC engines is the good combustion practice of operating and maintaining the engines according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, EPA proposes the following good combustion practices, in addition to the emission limits set forth below, as BACT for the engines:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operations and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

EPA proposes the following NO_X emission limits as representative of BACT for the smaller diesel IC engines, as shown in Table 4-1. The emission limits shown in Table 4-1 are derived from the emission factors or the emission rates and the engine ratings identified in Appendix A.

Table 4-1: NO_X Emission Limits for the Smaller Diesel IC Engines

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Emission Unit Number and Engine Name	NO_X Emission Limit (g/kW-hr)
FD-12 & 13, HPU Engines	13.155
FD-14 & 15, Deck Crane Engines	10.327
FD-16 & 17 Cementing Unit Engines	13.155
FD-18 Cementing Unit Engine	15.717
FD-19 Logging Unit Winch Engine	4.000
FD-20, Logging Unit Generator Engine	7.500

4.3.4 NO_x BACT for the Diesel-Fired Boilers (FD-21 to FD- 22)

Step 2 – Eliminate technically infeasible control options

The Discoverer has two small diesel fueled boilers (FD-21 and FD-22) to provide heat for domestic and work spaces. According to Shell's application, under typical operations, one boiler will be operating and the second will be on standby, although there may be times when both boilers operate simultaneously. The maximum heat input for each of the existing Clayton Model 200 boilers is approximately 8 million Btu per hour (MMBtu/hr). As shown in Appendix A, the total estimated emissions of NO_X from the two boilers are 6.46 tpy.

A search of the EPA RBLC and CA-BACT found that previous determinations for NO_X control of small boilers included no controls, low NO_X burners (LNB) and flue gas recirculation (FGR). Literature from Clayton Industries, the manufacturer of the two boilers, states that LNB are available only for natural gas or propane fired boilers (Shell Beaufort Permit Application 01/18/10, page 86), and are not available for the diesel fired boilers on the Discoverer. Clayton Industries also states that FGR is an available option for new boilers, but that they are not aware of any FGR retrofits to any of their existing boilers. There are no determinations for installing SCR on small boilers (<100 MMBtu/hr), nor is EPA aware of any instance where SCR has been installed on small boilers on exploration vessels. The boilers on the Discoverer are located next to the engine room, which is being expanded to accommodate the SCR systems for the generator engines. Shell states that after installation of the SCR for the generator engines, there will be no deck space for additional SCR units. For these reasons, EPA believes that LNB, FGR and SCR are technically infeasible for the small boilers at issue in this specific application.

Step 3 – Rank the remaining technologies by control effectiveness

The only technically feasible NO_X control option for the two boilers (FD-21 and FD-22) is good combustion practices.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since the top control option from Step 3 (good combustion practices) is the only technically feasible control option, this step is not required.

Step 5 – Select NO_X BACT for the diesel-fired boilers

EPA proposes that BACT for NO_X for the diesel-fired boilers be the good combustion practice of operating and maintaining the engines according to the manufacturer's recommendations to

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maximize fuel efficiency and minimize emissions. More specifically, EPA proposes the following good combustion practices, in addition to the emission limits set forth below, as BACT for the engines:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

The emission limit representative of NO_X BACT for the boilers is 0.20 pounds per million Btu (lb/MMBtu). This emission limit was derived from the emission rate and boiler size information provided in Appendix A.

4.3.5 NO_X BACT for the Incinerator (FD-23)

Step 2 – Eliminate technically infeasible control options

The Discoverer has a two-stage, batch charged incinerator capable of incinerating 276 pounds per hour of solid trash, or 6624 pounds per day; however, Shell has requested an operating restriction to limit the maximum amount of trash burned to no more than 1300 pounds per day. The maximum incineration capacity is rated at 3 MMBtu/hr. The use rate and batch size will be variable depending on the waste generation rate on board the Discoverer. The only determination for post-combustion controls for NO_X found in the EPA RBLC and CA-BACT searches was for selective non-catalytic reduction (SNCR), although that determination was for a much larger incinerator. Team Tec, the manufacturer of the incinerator on the Discoverer, was not aware of any control technologies that have been installed on this model of incinerator for control of NO_X (Shell Beaufort Permit Application 01/18/10, page 90). Since the heat content and the batch size charged to the incinerator will be quite variable, design of an SNCR control system would be infeasible. Therefore, EPA believes that SNCR is technically infeasible for this small incinerator.

Step 3 – Rank the remaining technologies by control effectiveness

The only technically feasible NO_X control option for the incinerator (FD-23) is good combustion practices.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since the top control option from Step 3 (good combustion practices) is the only technically feasible control option, this step is not required.

Step 5 – Select NO_X BACT for the incinerator

EPA proposes that BACT for NO_X for the incinerator be the good combustion practice of operating and maintaining the engines according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, EPA proposes the following good combustion practices, in addition to the emission limits set forth below, as BACT for the engines:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

The NO_X emission limit representative of BACT for the incinerator is 5.0 pounds of NO_X per ton of waste burned which is the same as the NO_X emission factor presented in the emission inventory in Appendix A.

4.4 PM/ PM_{10}/ $PM_{2.5}$ BACT Analysis

Step 1 – Identify all available control technologies

PM/ PM_{10}/ $PM_{2.5}$ emissions (hereafter referred to as particulate matter or PM[14]) from diesel engines are a complex mixture of compounds which are formed through a number of different mechanisms. Diesel PM emissions are comprised of the soluble organic fraction (SOF), the insoluble fraction, and the sulfate fraction. Fuel and lube oil contribute to the SOF fraction. The insoluble fraction is primarily dry carbonaceous soot from incomplete fuel combustion. The sulfate fraction is produced from the sulfur in diesel fuel. The available PM control technologies for the Discoverer's engines, boilers, and incinerator were determined from searches performed on the RBLC and the CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-3 of the Shell Beaufort Permit Application (01/18/10).

[14] As discussed above, except with respect to the incinterator, all PM and PM_{10} from all emission units on the Discoverer are assumed to be $PM_{2.5}$, a conservative assumption.

The available PM combustion control technologies for diesel IC engines identified in the RBLC and CA-BACT searches include low sulfur fuel (LSF), oxidation catalyst (OxyCat), diesel particulate filter (DPF), Tier 2 or Tier 3 level controls, and closed crankcase ventilation (CCV), which is sometimes referred to as positive crankcase ventilation (PCV). Although not listed in the RBLC or CA-BACT, the combination of OxyCat and DPF, referred to as a catalytic diesel particulate filter (CDPF), is also an available control technology for PM reduction. This list of available control technology is consistent with the list of diesel retrofit technologies that EPA has approved for use in engine retrofit programs (EPA 12/14/09 Verified Retrofit Technologies), and with the control technologies discussed in the Western Regional Air Partnership "Offroad Diesel Retrofit Guidance Document" (WRAP 11/28/05) and the Massachusetts Department of Environmental Protection "Diesel Engine Retrofits in the Construction Industry: A How To Guide" (MassDEP 01/08).

LSF reduces the sulfate PM fraction by limiting the amount of sulfur in the fuel that is available for sulfate formation. As described in Section 4.2, use of ultra-low sulfur was determined to represent BACT for SO_2 and has the added benefit of reducing the sulfate portion of PM emissions from emission units burning diesel fuel. An OxyCat removes the SOF of PM through catalytic oxidation of the combustible organic matter resulting in an overall PM control efficiency of about 50 percent. A DPF removes the insoluble fraction of PM (soot) by filtration with an overall PM control efficiency of 40 to 50 percent. CDPF technology removes both the SOF and the insoluble fraction of PM with an overall PM control efficiency of about 85 percent. According to information from CleanAIR Systems, a CDPF vendor, the CDPF must be operated at temperatures greater than 300ºC (572ºF) for a certain percentage of the operating time for proper filter regeneration when using low sulfur fuel (CleanAIR Systems 2009). Therefore, the capability to monitor temperature of the engine exhaust gas at the inlet of the CDPF should be required for those emission units for which CDPF technology is determined to represent BACT.

The crankcase of a combustion engine accumulates gases and oil mist called blow-by gases that leak into the crankcase from the combustion chamber and other sources. The blow-by gases must be vented from the crankcase to prevent damage to engine components such as seals. The blow-by gases contains PM, which is primarily SOF, and will contribute to PM emissions if not controlled. CCV systems were developed to remove blow-by gases from the engine and to prevent those vapors from being expelled into the atmosphere. The CCV system does this by directing the blow-by gases back to the intake manifold, so they can be combusted. Shell stated that all of the diesel IC engines on the Discoverer except for the MLC Compressor engines (FD – 9 to FD-11) will be equipped with a CCV system. The MLC Compressor engines have built-in crankcase emission control.

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than an applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. 40 C.F.R. § 52.21(b)(12)(definition of BACT). EPA has promulgated exhaust emission standards for stationary IC engines under the NSPS Subpart IIII which specifies that engine manufacturers must certify their 2007 and later engines to the applicable emission standard for new nonroad engines in 40 C.F.R. § 89.112 (and several other sections). 40 C.F.R. § 60.4201(a). Engines designed to meet Tier 2 or Tier 3 PM emission standards typically employ a combination of low PM emitting engine designs and DPF or CDPF. For diesel IC engines manufactured to meet the Tier 3 emission standards such as the three 540 hp MLC compressor engines (FD-9 to FD-11) and the 250 hp Logging Unit Winch engine (FD-

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19), the applicable PM emission standard is 0.2 grams per kilowatt hour (g/kW-hr). 40 C.F.R. § 89.112(a) Table 1.

No PM control technologies were found from the search of the RBLC and CA-BACT for diesel fired boilers less than or equal to 100 MMBtu/hr. Although 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 the Discoverer.

The only PM control technology for the incinerator found in the RBLC and CA-BACT search was an ESP although it was for a much larger incinerator than the one on the Discoverer. Other control devices such as a ceramic fabric filter, a venturi scrubber or a wet ESP could theoretically be designed for the small incinerator on the Discoverer and were evaluated as control options.

Good combustion practice of operating and maintaining the emission units according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions is also an available work practice for all emission units on the Discoverer.

4.4.1 PM BACT for the Generator Diesel IC Engines (FD-1 to FD- 6)

Step 2 – Eliminate technically infeasible control options

The available control technologies for the Discoverer's diesel IC engines are LSF, OxyCat, DPF, CDPF, Tier 2 or 3 level controls, and CCV. 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.

The primary difference between an OxyCat system and a CDPF is that the OxyCat system is constructed with an open flow catalyst matrix. In contrast, the CDPF is constructed with a catalyst matrix where the inlet channels of the catalyst matrix are plugged at the downstream end, forcing the exhaust gases to flow through the pores of the catalyst matrix and out the adjacent channels, which are plugged at the inlet end of the matrix. Because of this design difference, a CDPF achieves a higher percentage reduction of PM emissions but approximately the same percentage reduction for VOC and CO as compared to an OxyCat system, although at the expense of a higher pressure drop across the catalyst matrix.

The higher pressure drop of the CDPF is of concern because, as described in Section 4.3.1, the generator diesel IC engines will be equipped with the SCR system for NO_X control. The SCR catalyst imposes a backpressure on the engines due to the pressure drop required to move the exhaust gases through the SCR catalyst matrix. Adding the additional pressure drop associated with a CDPF could result in an excessive backpressure on the engines. D.E.C. Marine addressed the possibility of designing a CDPF to be used with the SCR system (Shell Beaufort Permit Application 01/18/10, Appendix C). Since a CDPF has not been included with the vendor's SCR systems in the past, a feasibility study would have to be conducted before final design. Several considerations would have to be addressed including the additional cross-sectional area needed for the CDPF catalyst matrix (perhaps as much as 50 percent larger than for an OxyCat matrix), the temperature profiles to determine how well the captured soot would be oxidized in the CDPF, the increased backpressure imposed and the manual cleaning frequency (or filter element exchange) required to keep the backpressure within specifications. D.E.C. Marine stated that they are not aware of any applications of CDPF systems on older heavy duty marine engines without modern electronic controlled fuel injection. Since 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.[15]

Step 3 – Rank the remaining technologies by control effectiveness

The remaining technically feasible controls for the generator diesel engines include OxyCat, LSF and good combustion practices for control of exhaust gas emissions. CCV or coalescing filters are available for control of crankcase emissions.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

The most efficient available technology is an OxyCat system with estimated removal efficiency of 50 percent for PM. As discussed in Section 4.2, EPA's view is that ultra-low sulfur fuel represents BACT for SO_2 control and will have the added benefit of reducing the sulfate fraction of the PM emissions. Therefore, ultra-low sulfur fuel can be considered, in conjunction with OxyCat, as a combination of PM control techniques. The proposed D.E.C. Marine design incorporates oxidation catalyst downstream of the SCR catalyst in the same converter shell, which results in a more compact and economical system than having separate devices. The OxyCat system is expected to reduce PM emissions to <0.127 g/kW-hr.

In addition to the exhaust gases from the engine, the generator diesel IC engines produce emissions from the crankcase, which must be ventilated to prevent pressure buildup from combustion gases that escape around the piston rings during the combustion stroke. Installation of CCV as a retrofit technology will eliminate crankcase PM emissions by recycling them back to the intake manifold of the engine. (Shell Beaufort Permit Application 01/18/10, pages 56-57)

Step 5 – Select PM BACT for the Generator Diesel IC Engines

EPA is proposing that BACT for PM from the generator diesel IC engines is 0.127 g/kW-hr based on the use of OxyCat in combination with use of ultra-low sulfur fuel (≤ 15 ppm).

The definition of BACT provides that if EPA determines that technological or economic limitations on the application of measurement technology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. 40 C.F.R. § 52.21(b)(12). Since quantifying PM emissions from crankcase ventilation is difficult and makes the imposition of an emission standard for the crankcase ventilation infeasible, EPA proposes that BACT for crankcase ventilation be a work practice of installing CCV systems which will eliminate any venting of crankcase emissions to the atmosphere.

In order to detect a major failure of the oxidation catalyst, EPA is also proposing a visible emissions (opacity) limit in addition to the particulate emission limit described above. EPA proposes that visible emissions from the engines, excluding condensed water vapor, shall not

[15] Even if a CDPF was technically feasible in this specific application, Shell estimated the cost effectiveness of a CDPF for the generator engines and found the cost effectiveness values to be in the range of $20,000 to $30,000 per ton of PM removed (Shell Beaufort Permit Application 01/18/10, page 58). This cost effectivness value exceeds what EPA believes to be representaitve of BAC for these engines.

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reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

4.4.2 PM BACT for the Compressor Diesel IC Engines (FD-9 to FD-11) and the Logging Unit Winch Engine (FD-19) (all Tier 3 Engines)

Step 2 – Eliminate technically infeasible control options

The compressor diesel IC engines and the Logging Unit Winch engine are newer and meet the EPA Tier 3 emission standards. According to the literature describing the Caterpillar C-15 engines, part of the control technology used on the C-15 engine includes clean gas induction which consists of a DPF and EGR (Caterpillar 2007). Therefore, the C-15 engines include the same type of diesel particulate filtration as achieved with a CDPF. The Tier 3 standard for PM is 0.2 g/kW-hr. Additional add-on PM control devices could be used, such as a CDPF, an OxyCat system or a DPF in series with the integral controls on the Tier 3 engines.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for the compressor diesel IC engines (FD-9 to FD-11) and the Logging Unit Winch engine (FD-19) are ranked by PM control effectiveness as follows:

1. CDPF – 85 percent control
2. OxyCat – 50 percent control
3. DPF – 40 – 50 percent control
4. Good combustion practices

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Shell included cost effectiveness calculations for a CDPF for the Compressor engines and the Logging Unit Winch engine (Shell Beaufort Permit Application 01/18/10, page 82). The calculated cost effectiveness value was $41,900/ton of PM removed for a CDPF on a compressor engine and $90,000/ton of PM removed for a CDPF on the Logging Unit Winch engine. Since the cost effectiveness values estimated for the CDPF on the Tier 3 engines are much greater than $10,000/ton commonly considered high for stationary source BACT determinations, EPA proposes that use of a CDPF does not represent BACT for the Tier 3 engines.

Similarly, Shell included a cost effectiveness calculation for an OxyCat system for the compressor engines and the Logging Unit Winch engine (Shell Beaufort Permit Application 01/18/10, page 82). The calculated cost effectiveness value was $32,100/ton of PM removed for an OxyCat system on a compressor engine and $55,200/ton of PM removed for an OxyCat system on the Logging Unit Winch engine. As in the case of the CDPF discussed above, the cost effectiveness values for an OxyCat system are higher than EPA considers reasonable for a BACT determination.

Since the cost of a DPF is not significantly lower than for an OxyCat and the PM removal efficiency is no greater than an OxyCat system, the cost effectiveness of a DPF on either of the Tier 3 engines is also greater than EPA considers reasonable for a BACT determination.

The remaining technically feasible control option is the use of good combustion practices.

Step 5 – Select PM BACT for the Compressor and Logging Unit Winch IC Engines

The CDPF, OxyCat and the DPF have been eliminated from consideration for use on Tier 3 engines based on unreasonably high cost effectiveness values. EPA proposes that BACT for PM for the compressor diesel IC engines and the Logging Unit Winch engine is that the engines meet the Tier 3 engine PM standard of 0.20 g/kW-hr and the use of good combustion practice for operating and maintaining the engines according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, EPA proposes the following good combustion practices, in addition to the emission limit set forth above, as BACT for the compressor engines and the Logging Unit Winch engine:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operations and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

In order to detect a significant degradation in the performance of the PM control system inherent to the compressor engines and the Logging Unit Winch engine, EPA is proposing a visible emissions (opacity) limit in addition to the PM emission limit described above. EPA proposes that visible emissions from the engines, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

4.4.3 PM BACT for the Smaller Diesel IC Engines (FD-12 to FD-18 and FD-20)

Step 2 – Eliminate technically infeasible control options

The available control technologies for the Discoverer's smaller diesel IC engines are LSF, OxyCat, DPF, CDPF, Tier 2 or 3 level controls, and CCV. Tier 2 or Tier 3 level controls are intrinsic to the original engine design. These control technologies are not technically feasible because they are not part of the design of the Discoverer's smaller diesel IC engines. LSF, OxyCat, DPF, and CDPF are all considered technically feasible for the smaller diesel IC engines.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible PM control technologies for the exhaust gases from the smaller diesel IC engines are ranked by control effectiveness as follows:

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1. CDPF – 85 percent control
2. OxyCat – 50 percent control
3. DPF – 40 to 50 percent control
4. Good combustion practices

Ultra-low sulfur fuel is included in combination with all the above technologies in determining the above control effectiveness.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since Shell proposed to install CDPF, which EPA agrees is the most effective control option, on each of the smaller diesel IC engines and there is no evidence that the most effective control option would have adverse environmental impacts as compared to other control options, no further analysis is required.

Step 5 – Select PM BACT for the Smaller Diesel Engines

EPA proposes that BACT for PM from the smaller diesel IC engines be an emission rate based on the use of CDPF technology in combination with use of ultra-low sulfur fuel. The BACT emission rate for each of the smaller diesel IC engines is shown in Table 4-2.

Table 4-2: PM Emission Limits for the Smaller Diesel IC Engines

Emission Unit Number and Engine Name	PM Emission Limit (g/kW-hr)
FD-12 & 13, HPU Engines	0.253
FD-14 & 15, Deck Crane Engines	0.0715
FD-16 & 17, Cementing Unit Engines	0.2530
FD-18 Cementing Unit	0.3860
FD-20, Logging Winch Engine	0.0900

As discussed in Section 4.4.1 above, since quantifying PM emissions from crankcase ventilation is difficult and makes the imposition of an emission standard for the crankcase ventilation infeasible, EPA proposes that BACT for crankcase ventilation be a work practice consisting of installation of CCV for all smaller diesel IC engines except for the MLC Compressor engines (FD 9 to FD-11) and the Logging Unit Winch Engine (FD-19), which have built-in crankcase emission control.

According to the information from CleanAIR Systems, a CDPF vendor, the CDPF must be operated at temperatures greater than 300ºC (572ºF) for a certain percentage of the operating time for proper filter regeneration when using low sulfur fuel. Therefore, EPA proposes that the permit include a condition requiring the permittee to monitor temperature of the engine exhaust gas at the inlet of the CDPF.

In order to detect a major failure of the CDPF control devices, EPA is also proposing a visible emissions (opacity) limit in addition to the PM emission limit described above. EPA proposes that visible emissions from the engines, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

4.4.4 PM BACT for the Diesel-Fired Boilers (FD-21 to FD-22)

Step 2 – Eliminate technically infeasible control options

No PM controls were found in the RBLC or CA-BACT search for small boilers.[16] Although it may be theoretically possible to design an ESP or a fabric filter for the small boilers on the Discoverer, one factor limiting the application of a fabric filter or an ESP on these boilers is that more than 50 percent of the PM from diesel fired boilers is condensable PM which would not be collected in a fabric filter or ESP at normal exhaust gas temperatures. As shown in Appendix A, the PM emissions for each boiler are 0.38 ton per year. Based on these factors, EPA considers a fabric filter or an ESP to be technically infeasible for control of PM from the boilers on the Discoverer. The use of ultra-low sulfur fuel for combustion will minimize the sulfate fraction of the PM emissions.

Step 3 – Rank the remaining technologies by control effectiveness

The only technically feasible PM control option for the two boilers (FD-21 and FD-22) is good combustion practices.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since the top control option from Step 3 (good combustion practices) is proposed as BACT, this step is not required.

Step 5 – Select PM BACT for the Diesel-Fired Boilers

EPA is proposing that good combustion practices represent BACT for PM for the diesel-fired boilers on the Discoverer. Good combustion practice for PM control essentially consists of operating and maintaining the boilers according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, EPA proposes the following good combustion practices, in addition to the emission limit set forth below, as BACT for the diesel-fired boilers on the Discoverer:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

[16] These control technologies are not found in practice because of the high cost of such control technology and the very small potential reduction in PM emissions.

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

EPA proposes that an emission limit representative of PM BACT for the boilers is 0.0235 pounds per million Btu (lb/MMBtu). This emission limit was derived from the emission rate and boiler size information provided in Appendix A.

In order to detect a major operating problem with the boilers, EPA is also proposing a visible emissions (opacity) limit in addition to the PM limit described above. EPA proposes that visible emissions from the boilers, excluding condensed water vapor, shall not reduce visibility through the exhaust effluent more than 20 percent averaged over any six consecutive minutes.

4.4.5 PM BACT for the Incinerator (FD-23)

Step 2 – Eliminate technically infeasible control options

Based on review of the RBLC and CA-BACT, the available control technologies for the Discoverer's incinerator (FD-23) are an ESP and good combustion practices. The incinerator listed in the RBLC with an ESP was rated at 350 tons per day (29,167 lb/hr), which is over 100 times the size of the incinerator on the Discoverer. Communication with TeamTec, the manufacturer of the incinerator on the Discoverer, indicated that they were not aware of any control technologies that have been installed on this model of incinerator for control of any of the pollutants including PM (Shell Beaufort Permit Application 01/18/10, page 90).

Shell summarized the results of a study conducted by GI Development LLC to evaluate PM control options for the incinerator (Shell Beaufort Permit Application 01/18/10, pages 90-96). The GI Development LLC study evaluated a dry ESP, a wet ESP, a venturi scrubber and a ceramic fiber baghouse.

Step 3 – Rank the remaining technologies by control effectiveness

1. Ceramic fabric baghouse – 99 percent control
2. Venturi scrubber – 90 percent control
3. Dry ESP – 75 percent control at the quoted size
4. Wet ESP – 75 percent control at the quoted size
5. Good combustion practices.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

The cost effectiveness value for the ceramic fiber baghouse based on a capital equipment cost of $220,000 was calculated to be $45,867/ton of PM removed (Environ 02/04/10). The high cost effectiveness value was due to both the high capital cost and the relatively low amount of potential PM removed (about 0.52 ton/year). This cost effectiveness value is higher than EPA considers reasonable for a BACT determination. Therefore, the ceramic fabric baghouse control device was eliminated from consideration in the BACT process.

The cost effectiveness value for the venturi scrubber based on a capital equipment cost of \$150,000 was calculated to be \$34,400/ton of PM removed (Environ 02/04/10). The high cost effectiveness value was due to both the high capital cost and the relatively low amount of potential PM removed (about 0.48 ton/year). This cost effectiveness value is higher than EPA considers reasonable for a BACT determination. Therefore, the venturi scrubber control device was eliminated from consideration in the BACT process.

Since both the dry and the wet ESP control devices have a higher capital cost (\$420,000 and \$175,000 respectively) and a lower PM control percentage than the venturi scrubber, the cost effectiveness values for either ESP is greater than for the venturi scrubber. Therefore, the dry and wet ESP control devices were eliminated from consideration in the BACT process.

The remaining control option is good combustion practices.

<u>Step 5 – Select PM BACT for the Incinerator</u>

Good combustion practices are determined to represent BACT for PM for the incinerator. Good combustion practice for PM control essentially consists of operating and maintaining the incinerator according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, good combustion practices for the incinerator consist of the following:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended scheduled operation and maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

In order to minimize emissions of PM, EPA proposes that the permit require that Shell develop and implement a written waste segregation work practice plan to ensure that non-combustible items containing heavy metals that could be volatilized and emitted from the incinerator as PM are not introduced into the incinerator.

The PM emission limit representative of BACT for the incinerator is 8.20 pounds of PM_{10} per ton of waste burned and 7.00 pounds of $PM_{2.5}$ per ton of waste burned. These emission limits are identical to the emission factors presented in the emission inventory in Appendix A.

4.5 CO and VOC BACT Analysis

Technology used to control CO emissions from combustion sources, including internal combustion engines, also provides control of volatile organic compound (VOC) emissions. Therefore, the following BACT analysis addresses CO and VOC control in combination.

Step 1 – Identify all available control technologies

The available CO and VOC control technologies for the Discoverer's engines, boilers, and incinerator were determined from searches performed on the RBLC and the CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-6 of the permit application. Crankcase ventilation gases from the diesel engines contain some VOC. CCV eliminates emissions from crankcase blow-by by directing these gases back to the intake manifold of the engine so they can be combusted.

The available CO and VOC combustion control technologies for diesel IC engines identified in the RBLC and CA-BACT are OxyCat and Tier 2 or Tier 3 diesel engine standards. OxyCat reduces CO/VOC emission through catalytic oxidation of these combustible gases. The OxyCat control system proposed for the generator diesel IC engines (and discussed in the Section 4.4.1 above) will provide an overall control efficiency of 80 percent for CO and approximately 70 percent for VOC according to D.E.C. Marine, the OxyCat vendor for the Discoverer's generator diesel IC engines (Shell Beaufort Permit Application 01/18/10, page 62). Diesel engines designed to meet Tier 2 or Tier 3 emission standards typically employ a combination of advanced combustion technology and catalytic oxidation. Although not listed in the RBLC or CA-BACT, a CDPF reduces CO and VOC emissions through catalytic oxidation with an overall control efficiency of up to 90 percent for both pollutants (Shell Beaufort Permit Application 01/18/10, page 84).

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than an applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. 40 C.F.R. § 52.21(b)(12)(definition of BACT). EPA has promulgated exhaust emission standards for stationary IC engines under the NSPS Subpart IIII which specifies that engine manufacturers must certify their 2007 and later engines to the applicable emission standard for new nonroad engines in 40 C.F.R. § 89.112 (and several other sections). 40 C.F.R. § 60.4201(a). Engines designed to meet Tier 2 or Tier 3 PM emission standards typically employ a combination of low PM emitting engine designs and DPF or CDPF. For diesel IC engines manufactured to meet the Tier 3 emission standards such as the three 540 hp MLC compressor engines (FD-9 to FD-11) and the 250 hp Logging Unit Winch engine (FD-19), the applicable CO emission standard is 3.5 grams per kilowatt hour (g/kW-hr). 40 C.F.R. § 89.112(a) Table 1. The VOC emission limit for Tier 3 engines is expressed as a combined value with NO_X (4.0 g/kW-hr).

No CO or VOC control technologies were found in the RBLC and CA-BACT searches for diesel-fired boilers less than or equal to 100 MMBtu/hr or for incinerators, nor are any CO or VOC control technologies found in practice for existing small boilers or incinerators. Therefore, good combustion practice is the only available control technology for consideration in this analysis for the diesel-fired boilers and the incinerator.

4.5.1 CO and VOC BACT for the Generator Diesel IC Engines (FD-1 to FD-6)

Step 2 – Eliminate technically infeasible control options

The available control technologies for the generator diesel IC engines are OxyCat, CDPF, Tier 2 or Tier 3 level controls, and CCV. Tier 2 or Tier 3 level controls are intrinsic to the original engine design; and, therefore, are not considered technically feasibility since they are not part of the design of the Discoverer's existing Caterpillar D399 diesel engines.

As discussed above in Section 4.4.1, the primary difference between an OxyCat system and a CDPF is that the OxyCat system is constructed with an open flow catalyst matrix. In contrast, the CDPF is constructed with a catalyst matrix where the inlet channels of the catalyst matrix are plugged at the downstream end, forcing the exhaust gases to flow through the pores of the catalyst matrix and out the adjacent channels, which are plugged at the inlet end of the matrix. Because of this design difference, a CDPF achieves a higher percentage reduction of PM emissions but approximately the same percentage reduction for VOC and CO as compared to an OxyCat system, although at the expense of a higher pressure drop across the catalyst matrix.

As also discussed above, the higher pressure drop of the CDPF is of concern because, as described in Section 4.3.1, the generator diesel IC engines will be equipped with the SCR system for NO_X control. The SCR catalyst imposes a backpressure on the engines due to the pressure drop required to move the exhaust gases through the SCR catalyst matrix. Adding the additional pressure drop associated with a CDPF could result in an excessive backpressure on the engines. D.E.C. Marine addressed the possibility of designing a CDPF to be used with the SCR system (Shell Beaufort Permit Application 01/18/10, Appendix C). Since a CDPF has not been included with their SCR systems in the past, a feasibility study would have to be conducted before final design. Several considerations would have to be addressed including the additional cross-sectional area needed for the CDPF catalyst matrix (perhaps as much as 50 percent larger than for an OxyCat matrix), the temperature profiles to determine how well the captured soot would be oxidized in the CDPF, the increased backpressure imposed and the manual cleaning frequency (or filter element exchange) required to keep the backpressure within specifications. D.E.C. Marine states that they are not aware of any applications of CDPF systems on older heavy duty marine engines without modern electronic controlled fuel injection. Since 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 that CDPF systems are technically infeasible for this specific application.[17]

Step 3 – Rank the remaining technologies by control effectiveness

The remaining technically feasible controls for the generator diesel IC engines include OxyCat and good combustion practices for control of exhaust gas emissions.

[17] Even if a CDPF was technologically feasible in this specific application, Shell estimated the cost effectiveness of a CDPF for the generator engines and found the cost effectiveness values to be in the $20,000 to $30,000 per ton of PM removed (Shell Beaufort Permit Application 01/18/10, page 58). Using a similar cost effectiveness calculation procedure, EPA estimated that the cost effectiveness value for a CDPF to control CO and VOC was approximately $40,000 per ton of CO and VOC removed. These cost effectiveness values exceed what EPA believes is representative of BACT for these engines.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

The most efficient available technology is an OxyCat system with estimated control efficiency of 80 percent for CO and 70 percent for VOC. The design proposed by D.E.C. Marine incorporates oxidation catalyst downstream of the SCR catalyst in the same converter shell, which results in a more compact and economical system than having separate devices. The OxyCat system is expected to reduce CO emissions to <0.179 g/kW-hr and VOC emissions to <0.0229 g/kW-hr.

In addition to the exhaust gases from the engine, the diesel generator engines produce emissions from the crankcase, which must be vented to prevent pressure buildup from combustion gases that escape around the piston rings during the combustion stroke. As discussed above in Section 4.4.1, EPA is proposing that CCV represents BACT for PM. Installation of CCV will also control CO and VOC emissions by recycling them back to the intake manifold so that they can be combusted.

Step 5 – Select CO and VOC BACT for the Generator Diesel IC Engines

EPA proposes that BACT for CO and VOC for the generator diesel IC engines is an emission limit of 0.1790 g/kW-hr for CO and 0.0230 g/kW-hr for VOC based on the use of OxyCat technology.

4.5.2 CO and VOC BACT for the Compressor Diesel IC Engines (FD- 9 to FD-11) and the Logging Unit Winch Engine (FD-19) (all Tier 3 Engines)

Step 2 – Eliminate technically infeasible control options

Shell proposed that engines meeting the Tier 3 emission standards represent BACT. However, there is no technical reason why add-on controls can not be considered for Tier 3 engines. The available control technologies for the Tier 3 diesel IC engines include CDPF, OxyCat, and good combustion practices. CCV is included as an inherent feature of the Tier 3 engines.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for the smaller diesel engines are ranked by control effectiveness:

1. CDPF – 80 percent control for CO and VOC
2. OxyCat – 47 percent control for CO and VOC
3. Good combustion practices

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

The cost effectiveness value for a CDPF for each of the compressor engines was calculated to be $9,848/ton of CO removed and the cost effectiveness value for an OxyCat for each of the compressor engines was calculated to be $4,323/ton of CO removed (Shell Beaufort Permit Application 01/18/10, page 85). The cost effectiveness values were calculated assuming the baseline emission rate was equal to the Tier 3 CO engine standard of 3.5 g/kW-hr. Since the cost effectiveness value for the CDPF was near the high end of the range that EPA considers reasonable, the incremental cost effectiveness value between an OxyCat and a CDPF was evaluated to determine whether the additional cost to move from an OxyCat to a CDPF for the compressor engines was justified. The incremental cost effectiveness value was calculated to be

$17,700/ton of CO removed. Because the incremental cost effectiveness value between an OxyCat and a CDPF is so large, EPA proposes that an OxyCat is representative of BACT for the compressor engines.

The cost effectiveness value for a CDPF for the Logging Unit Winch engine was calculated to be $3,329/ton of CO removed, a cost effectiveness value that EPA considers reasonable. Therefore, EPA proposes that a CDPF is representative of BACT for the Logging Unit Winch engine.

Step 5 – Select CO/VOC BACT for the Compressor and Logging Unit Winch Diesel IC Engines

EPA proposes that BACT for CO from the compressor diesel IC engines is an emission limit of 1.86 g/kW-hr based on the use of an OxyCat. EPA proposes that BACT for CO from the Logging Unit Winch diesel IC engine is an emission limit of 0.70 g/kW-hr based on the use of a CDPF. For these Tier 3 engines, the VOC emissions are included in determining compliance with the NO_X emission limit described in Section 4.3.2.

The use of an OxyCat on the compressor engines and a CDPF on the Logging Unit Winch engine will concurrently reduce PM emissions by 50 percent and 85 percent, respectively. Therefore, EPA proposes to reduce the PM emission limits for the Tier 3 engines to 0.10 g/kW-hr for the compressor engines and 0.03 g/kW-hr for the Logging Unit Winch engine.

According to the information from CleanAIR Systems, a CDPF vendor, the CDPF must be operated at temperatures greater than 300ºC (572ºF) for a certain percentage of the operating time for proper filter regeneration using low sulfur fuel. Therefore, EPA proposes to include in the permit a condition requiring monitoring of the temperature of the engine exhaust gas at the inlet of the CDPF.

4.5.3 CO and VOC BACT for the Smaller Diesel IC Engines (FD-12 to FD-18 and FD-20)

Step 2 – Eliminate technically infeasible control options

The available control technologies for the smaller diesel IC engines include CDPF, OxyCat, Tier 2 or Tier 3 engine standards, CCV and good combustion practices. Tier 2 or Tier 3 engine standards are intrinsic to the original engine design and are not technically feasible for the smaller, existing diesel IC engines on the Discoverer.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for the smaller diesel engines are ranked by control effectiveness:

1. CDPF – 90 percent control for CO and VOC
2. OxyCat – 80 percent control for CO and 70 percent control for VOC
3. Good combustion practices

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Shell proposed to use CDPF, the top control option, for all of the smaller diesel IC engines that are not Tier 3 engines. Therefore, no further analysis is required.

Step 5 – Select CO/VOC BACT for the Smaller Diesel Engines

EPA proposes that BACT for CO and VOC is the emission limits shown in Table 4-3 below based on the use of CDPF. The CO and VOC emissions limits are based on a 90 percent reduction of uncontrolled emissions from the engines.

Table 4-3: CO and VOC Emission Limits for the Smaller Diesel IC Engines

Emission Unit Number and Engine Name	VOC Emission Limit (g/kW-hr)	CO Emission Limit (g/kW-hr)
FD-12 & 13, HPU Engines	0.200	0.400
FD-14 & 15, Deck Crane Engines	0.064	0.220
FD-16 & 17, Cementing Unit Engines	0.200	0.400
FD-18 Cementing Unit Engine	0.270	0.880
FD-20, Logging Unit Generator Engine	0.750	0.550

According to the information from CleanAIR Systems, a CDPF vendor, the CDPF must be operated at temperatures greater than 300ºC (572ºF) for a certain percentage of the operating time for proper filter regeneration using low sulfur fuel. Therefore, EPA proposes to include in the permit a condition requiring monitoring of the temperature of the engine exhaust gas at the inlet of the CDPF.

In addition to the exhaust gases from the engine, the smaller diesel IC engines produce emissions from the crankcase, which must be ventilated to prevent pressure buildup from combustion gases that escape around the piston rings during the combustion stroke. EPA believes that CCV represents BACT for PM. Installation of CCV will also control CO and VOC emissions by recycling them back to the intake manifold so that they can be combusted.

4.5.4 CO and VOC BACT for the Diesel-Fired Boilers (FD-21 to FD-22) and the Incinerator (FD 23)

Step 2 – Eliminate technically infeasible control options

No CO or VOC controls were found in the RBLC or CA-BACT searches for small boilers and incinerators. As shown in Appendix A, the CO and VOC emissions for each boiler are 1.25 tpy and 0.02 tpy, respectively. Similarly, the CO and VOC emissions for the incinerator are 1.69 tpy and 0.16 tpy, respectively.

Step 3 – Rank the remaining technologies by control effectiveness

The only technically feasible CO and VOC control option for the two boilers (FD-21 and FD-22) and the incinerator (FD-23) is good combustion practices.

Step 4 – Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts

Since the only control option from Step 3 (good combustion practices) is proposed as BACT, this step is not required.

Step 5 – Select CO and VOC BACT for the Diesel-Fired Boilers and the Incinerator

EPA proposes that good combustion practices represent BACT for CO and VOC for the diesel-fired boilers and the incinerator. Good combustion practice for CO and VOC control essentially consists of operating and maintaining the boilers and the incinerator according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions. More specifically, good combustion practices for the boilers and the incinerator consist of the following:

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,
- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,
- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,
- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,
- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

EPA proposes that the permit include a condition requiring the permittee to follow the good combustion practices listed above.

EPA proposes that the emission limits shown in Table 4-4 below are representative of CO and VOC BACT for the boilers and the incinerator. The emission limits for the boilers are derived from the emission rate and boiler capacity information in the emission inventory in Appendix A. The emission limits for the incinerator are identical to the emission factors for the incinerator from the emission inventory in Appendix A.

Table 4-4: CO and VOC Emission Limits for the Boiler and Incinerator

Emission Unit	VOC Emission Limit	CO Emission Limit
Boilers (FD-21 & 22)	0.00140 lb/MMBtu	0.0770 lb/MMBtu
Incinerator (FD-23	3.0 lb/ton of waste burned	31.0 lb/ton of waste burned

4.6 BACT for the Drilling Mud De-gassing Operation (FD-32)

In the Chukchi permit application Shell estimated VOC emissions of 128 pounds per drilling season from drilling mud degassing operations. This VOC emission rate is expected to be similar for the Beaufort Sea lease blocks (Shell Beaufort Permit Application 01/18/10, page 98).

Drilling mud is used to lubricate and carry away heat from the drill bit and to transport drill cuttings to the surface. When the drill passes through a hydrocarbon zone, hydrocarbons in the drill cuttings are carried to the surface (the deck of the Discoverer) with the mud. The mud is directed to the "ditch", then the shakers and then to the mud pit. These pieces of equipment are exposed to the atmosphere and any trapped gases such as hydrocarbons, water vapor or carbon dioxide flash out of the mud. If high concentrations of hydrocarbons from the mud are detected, the mud it diverted to a mud separator where gases flashed from the mud are directed through a 10 inch diameter pipe and vented at the top of the drilling derrick as a safety precaution to prevent exposure to workers and to keep the potentially explosive gases away from ignition sources.

To control all VOC emissions from mud degassing, the mud-handling system would need to be redesigned to collect gas from both the open mud processing areas and from the mud gas separator. The gas collection system would need to be designed to handle a gas volumetric flow rate up to 500 cubic feet per minute associated with emergency and unexpected releases, but normally would process very small gas flows. With such a variable flow rate, condensers, carbon adsorption or routing the gases to the air intake of an on-board combustion device would not be technically feasible. A flare is the only VOC control device that is capable of handling this type of gas service.

Shell provided cost information for a flare based on information from the EPA Air Pollution Cost Control Manual. The annualized cost for a small flare (2 inch diameter nozzle) from Table 2.13 of the EPA Air Pollution Cost Control Manual was $61,800. This annualized cost value is likely an underestimate of the cost as applied to Shell's operation since it was for an on-land flare which is less expensive to construct compared to an on-ship flare system and was based on 2002 dollars. However, using the annualized cost of $61,800, the cost effectiveness value for controlling 128 pounds of VOC per year was calculated to be $965,625/ton of VOC removed (assuming 100 percent destruction of the VOC in the flare). A cost effectiveness value of this magnitude is much higher than EPA considers reasonable for a BACT determination. Therefore, EPA proposes that BACT for the mud de-gassing operation on the Discoverer is the use of the existing equipment.

4.7 BACT for the Supply Vessel at Discoverer (FD-31)

Aside from the supply vessel and the cuttings/muds barge, the vessels in the Associated Fleet will not be physically attached to the Discover, and therefore will not be part of the OCS source and not subject to the BACT requirement. The cutting/muds barge will also be attached however Shell indicated that no air pollution emitting emission units will operate on the barge while it is attached to the Discoverer. Therefore, BACT is not required for the cuttings/mud barge. The supply vessel will be part of the OCS source and thus subject to BACT only for the relatively short period of time it will be tied to the Discoverer. Shell estimated a maximum of eight resupply events per year. When the supplies are delivered to the Discoverer, the supply vessel would be attached to the Discoverer for a maximum of 12 hours with one generator diesel engine of less than 300 horsepower operating. The maximum time a supply vessel would be attached to the Discoverer and thus considered part of the “OCS source” would be 96 hours for the drilling season. The estimated emissions from the supply vessel while tied to the Discoverer based on the maximum time of 96 hours are shown in Appendix A. The largest value is 0.43 tpy for NO_X. The estimated emissions in units of tpy for all other pollutants are smaller: 0.09 for CO; 0.03 for PM; 0.03 for VOC; and 0.0002 for SO_2. Because of the very small emission reduction potential and the short time period over which any control technology would be amortized, EPA believes that installation of any additional control technology on the supply vessels would not be cost effective. Shell provided cost effectiveness calculations for several control alternatives that could be applied to the generator engine on the supply vessel. In all cases the calculated cost effectiveness values were much greater than EPA considers reasonable for BACT determinations. For example, the calculated cost effectiveness values for the supply vessel generator engine were approximately: $187,000/ton of PM for a CDPF; $114,000/ton of PM for an OxyCat; and $228,000/ton of PM for a DPF (Shell Beaufort Permit Application 01/18/10, page 79). These cost effectiveness values are much greater that EPA considers reasonable within the context of a BACT determination. Thus, EPA proposes that BACT for the supply vessel is no additional add-on controls. Shell has agreed, and the permit proposes, that Shell use ULSD fuel in all vessels in the Associated Fleet, including the supply vessel to assure attainment of the NAAQS and compliance with increment.

4.8 Reference Test Methods

This section describes the reference test methods EPA is proposing for the emission limits discussed above.

EPA is proposing that BACT for SO_2 is the use of ULSD fuel (≤0.0015 percent by weight). A representative fuel sample for sulfur analysis must be collected by one of the methods identified in 40 C.F.R. § 80.330(b). Any test method for determining the sulfur content of diesel fuel must satisfy the EPA approval process contained in 40 C.F.R. § 80.585(a) and the precision and accuracy requirements of 40 C.F.R. § 80.584. As an alternative, the sulfur content of the diesel fuel may be determined using ASTM D 5453-09. The permit specifies the frequency of the required testing. The testing requirement can also be met by obtaining a certification from the fuel supplier that the fuel meets the sulfur specification based on testing using the methods described above.

EPA proposes that all other emission limits be based on the average of three one hour test runs, with the arithmetic average of the three runs compared to the applicable emission limit.

NO_X emissions shall be measured using EPA Method 7E. EPA Method 7E is the performance test method required by a number of EPA NSPS for sources similar to those on the Discoverer such as steam generating units, gas turbines and large stationary IC engines.

CO shall be measured using EPA Method 10. EPA Method 10 is the performance test method required by the EPA NSPS for petroleum refinery fluid catalytic cracking units which typically include a boiler fueled by off-gas containing CO.

Ammonia emissions shall be measured using Conditional Test Method 027 (CTM-027) or CTM-038.

Except for the incinerator, $PM_{2.5,}$ PM_{10} and $PM_{2.5}$ emissions shall be measured using EPA Method 201/201A and Other Test Method 28 (OTM 28). Once proposed revisions to EPA Method 202 are finalized, see 56 FR 12970 (March 25, 2009), the permit requires the use of EPA Method 202 in place of OTM 28 to measure condensable particulate matter.

For the incinerator only, $PM_{2.5}$ emissions shall be measured using OTM 27 and OTM 28 until EPA finalizes the pending revisions proposed in 56 FR 12970 (March 25, 2009), at which time $PM_{2.5}$ emissions from the incinerator will be measured using the revised EPA Methods 201/201A and 202.

For opacity standards, EPA is proposing EPA Method 9 (40 C.F.R. Part 60, Appendix A) as the reference test method for opacity standards with numerical limits for point sources, with an averaging period of six minutes and an observation interval of 15 seconds.

EPA Methods 1, 2, 3A, 3B, 4 and 19 shall be used as needed to convert the measured NO_X, PM, PM_{10}, $PM_{2.5}$ and CO emissions into units of the emission limits in the permit. The EPA Methods identified in this section can be found in 40 C.F.R. Part 60, Appendix A, in 40 C.F.R. Part 51, Appendix M or on the EPA Emission Measurement Center webpage http://www.epa.gov/ttn/emc/. Permit Condition B.20 contains procedures for Shell to request and for EPA to approve alternatives to or deviations from the referenced test methods.

5 AIR QUALITY IMPACT ANALYSIS

5.1 Required Analyses

The PSD rules and implementing guidance require the permit applicant to demonstrate that, for all criteria air pollutants that would be emitted in excess of the significance thresholds at 40 C.F.R. § 52.21(b)(23)(i), the allowable emission increases (including secondary emissions) from a proposed new major stationary source, in conjunction with all other applicable emission increases or reductions at the source, would not cause or contribute to a violation of any NAAQS nor cause or contribute to a violation of any applicable "maximum allowable increase" over the baseline concentration in any area. The analysis must be based on air quality models, databases, and other requirements specified in the Guideline on Air Quality Models at 40 C.F.R. 51, Appendix W. The ambient air quality impact analyses for Shell's exploration drilling program are different from most that are received and reviewed by EPA in that (1) exploratory drilling operations will occur on the OCS in the Beaufort Sea, (2) drilling will occur at different lease blocks within a 60 kilometers by 95 kilometers area, and (3) combustion units are on board stationary and moving vessels.

As discussed in Section 2.2 above, the PSD requirements apply to emissions of CO, NO_X, PM, $PM_{2.5}$, PM_{10}, SO_2 and VOC from Shell's exploratory drilling program. Of these pollutants, NAAQS have been promulgated for CO, NO_2 (for NO_X), $PM_{2.5}$ (including precursors SO_2 and NO_X), PM_{10}, SO_2 and ozone (represented by precursors VOC and NO_X).

The "maximum allowable increases," also known as PSD increments, are listed in 40 C.F.R. § 52.21(c). There are PSD increments applicable to areas designated Class I, II and III. Class I areas are defined in 40 C.F.R. § 52.21(e). Mandatory Class I areas (which may not be redesignated to Class II or III) are international parks, national wilderness areas larger than 5,000 acres, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres. Class II areas are defined in 40 C.F.R. § 52.21(g) as all areas not initially designated Class I. The region covered by Shell's leases is a Class II area. See CAA Section 162(b). No areas have been redesignated to Class III that might be impacted by this project. The NAAQS and PSD Class I and II increments are listed in Table 5-4.

40 C.F.R. § 52.21(m) requires a PSD permit application to include an air quality analysis in connection with the demonstration required by 40 C.F.R. § 52.21(k)[18]. For each pollutant for which a NAAQS or PSD increment exists, 40 C.F.R. § 52.21(m)(1)(iv) requires the analysis to include at least one year of pre-construction ambient air quality monitoring data, unless EPA approves a shorter monitoring period (not less than four months). 40 C.F.R. § 52.21(i)(5)(i) allows exemption from the requirement for pre-construction ambient monitoring if the net emissions increase of a pollutant from the proposed source or modification would cause air quality impact less than the ambient monitoring thresholds listed in 40 C.F.R. § 52.21(i)(5)(i). See Table 5-14. For each pollutant for which no NAAQS has been established, 40 C.F.R. § 52.21(m)(1)(ii) allows EPA to require monitoring as determined to be necessary to assess

[18] As explained in Section 2.8 above, this permit applies in areas subject to § 52.21 and areas subject to the PSD permit provisions in 18 AAC 50.306 as incorporated into Part 55. The applicable Alaska ambient impact analyses requirements are consistent with the PSD requirements in § 52.21. Thus for ease and understandability this section of the Statement of Basis refers only to the Federal ambient impact analysis requirements in § 52.21.

ambient air quality for that pollutant in the area. In addition, 40 C.F.R. § 52.21(m)(2) authorizes EPA to require post-construction ambient air quality monitoring if EPA determines it is necessary to determine the effect that emissions from the source or modification may have on air quality.

40 C.F.R. § 52.21(o) requires an additional impact analyses, which must include an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the proposed source or modification, or that would occur as a result of any commercial, residential, industrial and other growth associated with the source or modification. Analysis for vegetation having no significant commercial or recreational value is not required.

For sources impacting Federal Class I areas, 40 C.F.R.§ 52.21(p) requires EPA to consider any demonstration by the Federal Land Manager that emissions from the proposed source modification would have an adverse impact on air quality related values, including visibility impairment. If EPA concurs with the demonstration, the rules require that EPA shall not issue the PSD permit.

5.2 Class II PSD Increments and NAAQS

5.2.1 PSD Baseline Dates

Figure 2-1 shows the location of the Shell Beaufort Sea lease blocks relative to the northern Alaska coastline. For sources locating on the OCS more than 25 miles from the State's seaward boundary (the Outer OCS), EPA considers the "baseline area" for purposes of 40 C.F.R. § 52.21 to be the area bounded on the shoreward side by a parallel line 25 miles from the State's seaward boundary; on the seaward side by the boundary of U.S. territorial waters; and on the other two sides by the seaward extension of the onshore Air Quality Control Region (AQCR) boundaries (EPA 07/02/09 Baseline Memo). OCS sources within 25 miles from the State's seaward boundary (the Inner OCS) are subject to the COA PSD regulations, including the minor source baseline dates established for the COA, so defining a "baseline area" for the Inner OCS is unnecessary. Effectively, those portions of the Beaufort Sea encompassing the Inner OCS and the Outer OCS are separate baseline areas with different minor source baseline dates.

The major stationary source baseline date, as defined in 40 C.F.R. § 52.21(b)(14)(i), and the trigger dates for SO_2, NO_2, and PM_{10} for this baseline area are shown in Table 5.1.

Table 5-1: Major Source Baseline Dates

Air Pollutant	Major Stationary Source	Trigger Date
Sulfur Dioxide	June 5, 1975	August 7, 1977
Nitrogen Dioxide	February 8, 1988	February 8, 2008
Particulate Matter	June 5, 1975	August 7, 1977

The minor source baseline date is established in an area when the first complete PSD application is submitted to EPA after the trigger date. See 40 C.F.R. § 52.21(b)(14)(i). EPA deemed the

Shell OCS/PSD application for exploratory drilling in the Chukchi Sea complete on July 31, 2009 (EPA 07/31/09 Completeness Letter), which effectively establishes July 31, 2009 as the minor source baseline date for SO_2, NO_2, and PM_{10} in the Chukchi Sea/Beaufort Sea Outer OCS baseline area. As a result, Shell is required to consider increment consuming emissions increases and decreases after July 31, 2009 from other sources in the area in its analysis of compliance with air quality increments. Due to the size of the AQCR and the location of the Shell Chukchi Sea drilling area relative to the Beaufort drilling area, emissions from the Chukchi project are not expected to have a significant impact at the Shell Beaufort Sea drilling area. Since the minor source baseline dates of the corresponding shore area apply in the Inner OCS, additional increment-consuming sources are required to be considered for modeled receptor locations in the Inner OCS. The minor source baseline dates have been triggered in this AQCR as shown in Table 5.2 below (Schuler 07/02/09). Shell disagrees with EPA's interpretation of this point, but included existing onshore sources within 100 kilometers of Shell's lease blocks in its PSD increment analysis. (Shell Beaufort Permit Application 01/18/10, Section 3.3.3)

Table 5-2: Minor Baseline Dates

Air Pollutant	Minor Source Baseline Date Beyond 25 Miles from the State Seaward Boundary	Minor Source Baseline Date Onshore and Within 25 Miles from the State Seaward Boundary
Nitrogen Dioxide	July 31, 2009	February 8, 1988
Particulate Matter	July 31, 2009	November 13, 1978
Sulfur Dioxide	July 31, 2009	June 1, 1979

Shell anticipates constructing a warehouse on shore which would have an oil fired heater in the existing Northern Alaska Intrastate AQCR. The PSD analysis of this source would be based on the onshore minor source baseline dates.

5.2.2 PSD Significant Impact Analysis

The PSD air quality analysis for Shell's exploratory drilling program was conducted in two basic stages. First, Shell conducted a screening analysis to determine the pollutants for which the project exceeded the significant impact levels and for which a more robust air quality demonstration would be required. Second, where the predicted maximum concentration of the specific air pollutant was greater than the applicable significant impact level, a full PSD increment and NAAQS analysis was performed for the pollutant. EPA guidance calls for a more detailed air quality analysis if the emission rate of a pollutant is significant, and if the predicted maximum ambient air concentration of the specific air pollutant is greater than the applicable significant impact level. (See e.g. EPA 10/90 Draft NSR Manual) As shown in Table 5-3, the highest concentration impact from the Discoverer and the Associated Fleet predicted by the screening analysis for the applicable averaging time exceeded the significant impact levels for NO_2 and PM_{10}. As a result, a detailed ambient air quality impact analysis is required for these air pollutants. An air quality analysis is also required for ozone because NO_2 and VOC emissions exceed 100 tpy. See 40 C.F.R. § 52.21(i)(5). In addition, because EPA has not promulgated a $PM_{2.5}$ significant impact level, a NAAQS analysis is required for this air pollutant. Shell also provided an analysis for SO_2, although Shell's commitment to use ULSD fuel in the Associated Fleet has now reduced overall SO_2 emissions below the PSD thresholds. At the time of the original application and previous proposed permit, the PTE for SO_2 exceeded the PSD thresholds and the current PSD permit application still includes a BACT analysis for the Discoverer and a demonstration that SO_2 emissions comply with the NAAQS and applicable PSD increments.

5.2.3 Significant Impact Radii

The significant impact levels are also used to determine the significant impact area (SIA) radii. The SIA radius is the farthest distance from a stationary source or major modification in which the concentration predicted by an EPA-accepted model exceeds the significant impact level. EPA guidance limits the SIA radius to 50 kilometers. (40 C.F.R. Part 51, Appendix W.) In this case, the SIA radius for annual NO_2 was set to 50 kilometers because the model predictions had not fallen below the significant impact level at this distance. A circular region with radius equal to the largest SIA radius for each pollutant, known as the significant impact area, is used as the modeling domain for the full NAAQS and PSD increment modeling analyses. Table 5-3 shows the significant impact levels and SIA radii for the Shell Beaufort Sea OCS leases.

Table 5-3: Class II Area Significant Impact Levels and Radius

Air Pollutant	Averaging Time	Predicted (µg/m³)	SIL (µg/m³)	Distance to Peak (m)	SIA Radius [a] (km)
Sulfur Dioxide (SO_2)	3-Hour	24.4	25	81	none [c]
	24-Hour	1.3	5	81	none [c]
	Annual	0.1	1	81	none [c]
Nitrogen Dioxide (NO_2)	Annual	19.1	1	2281	50.00
Carbon Monoxide (CO)	1-Hour	611.7	2000	5097	none [c]
	8-Hour	358.0	500	4897	none [c]
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	19.4	5	2406	42.0
	Annual	1.1	1	81	0.1
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	18.2	1	2406	NA [b]
	Annual	1.1	[b]	81	NA [b]
Ozone (O_3)			[b]		

Reference: Shell Beaufort Permit Application 01/18/10
NA ≡ Not Applicable. SIL ≡ Significant Impact Level

a. The significant impact area radius is the furthest modeled distance in which there is a significant impact, or a maximum radius of 50 km.
b. Because EPA has not promulgated $PM_{2.5}$ significant impact levels, a NAAQS analysis is required for this air pollutant.
c. The significant impact level was not exceeded; therefore no significant impact radius is defined.

5.2.4 Air Quality Standards

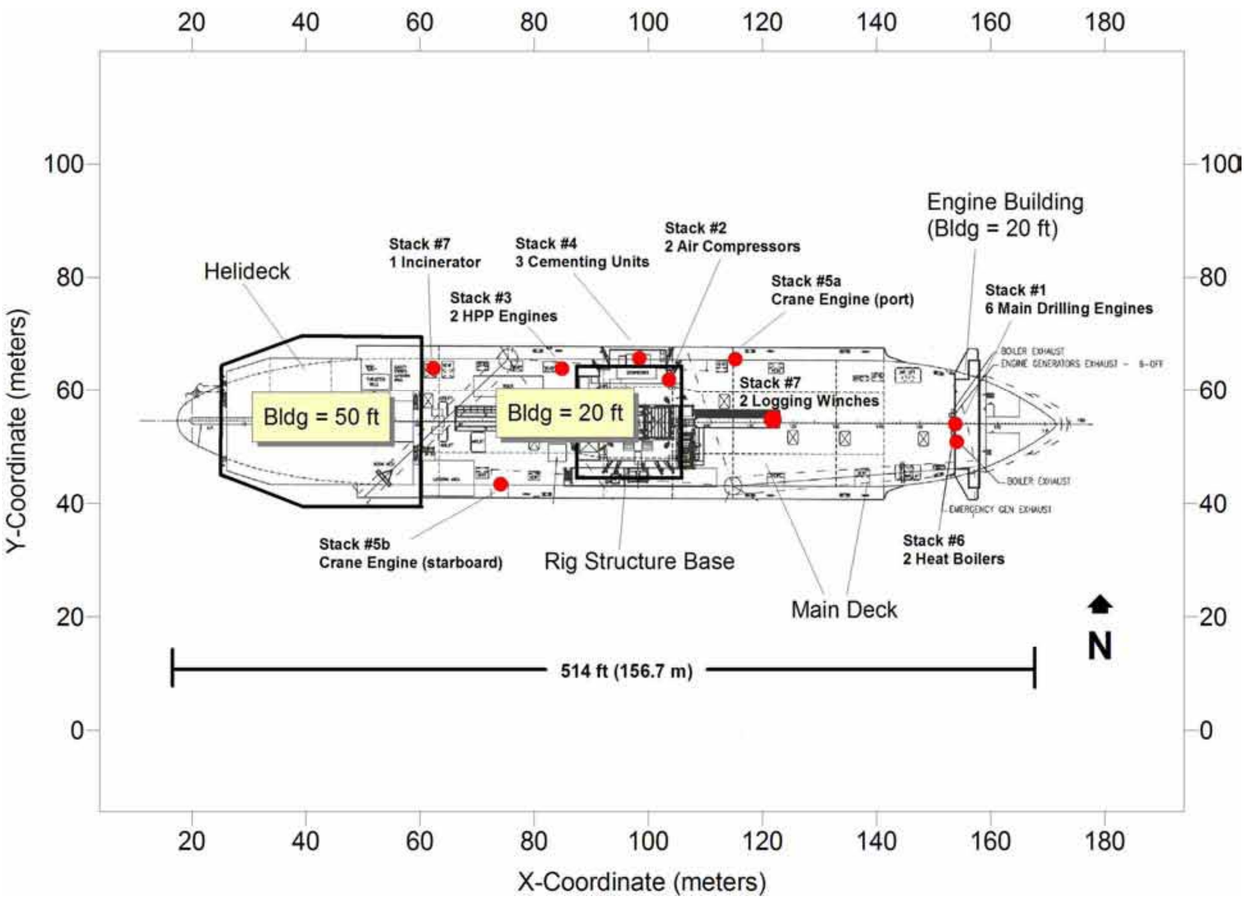
Table 5-4: Ambient Air Quality Standards, Air Quality Increments, and Impact Area and Monitoring Thresholds

Air Pollutant	Averaging Period	Air Quality Standards [a]		PSD Increments [b]	
		Primary ($\mu g/m^3$)	Secondary ($\mu g/m^3$)	Class I Area ($\mu g/m^3$)	Class II Area ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-Hour		1300	25	512
	24-Hour	365		5	91
	Annual	80		2	20
Nitrogen Dioxide (NO_2)	Annual	100	100	2.5	25
Carbon Monoxide (CO)	1-Hour	40000			
	8-Hour	10000			
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	150	150	8	30
	Annual			4	17
Particulate matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	35	35		
	Annual	15	15		
Lead (Pb)	Rolling 3-Month	0.15	0.15		
	Quarterly Average	1.5	1.5		
Ozone (O_3)	1-Hour	0.12 [c]	0.12 [c]		
	8-Hour [d]	0.75 [c]	0.75 [c]		
	8-Hour [e]	0.80 [c]	0.80 [c]		

a. Reference: 40 C.F.R. Part 50

b. Reference: 40 C.F.R. Part 52.21(c)
c. Units in parts per million (ppm)
d. 2008 standard
e. 1997 standard

Figure 5-1: Discoverer and Onboard Emission Units



5.2.5 Shell Operating Scenarios

Shell's proposed project consists of positioning the 514-foot drillship Discoverer (shown in Figure 5-1) within one of its lease blocks, setting anchors to stabilize the ship, and drilling into the seafloor. A support fleet will patrol at a distance to break ice, transfer supplies and personnel, and provide assistance in case of any oil spillage. In order to fully analyze the project's potential emissions and air impacts, accounting for the possible movement of the support vessels, several operating scenarios have been defined.

The base operating scenario (Base Operations) is the continuous overwater operation of the Discoverer with ice management and OSR vessels operating at a certain distance from the Discoverer. Included in the base operating scenario is the approach and docking of a resupply ship, presumed to be the *Kilabuk*, which could travel to the Discoverer up to eight times in a drilling season. Shell is also considering using a tug and barge in place of the resupply ship *Kilabuk*. The barge will have no emissions while attached to the Discoverer, and the tug is expected to have lower emissions than the *Kilabuk* during transit. The tug and barge were not separately included in the Shell Beaufort Sea modeling analysis but Condition Q.4 of the permit requires emissions from any tug and barge in transit to comply with the same requirements as the *Kilabuk*.

There are nine other operating scenarios (Scenarios 1-9, summarized in Table 5-5 and are further described in Section 5.2.22 below). These scenarios consider situations where other support vessels must approach the Discoverer; different levels of usage of the Discoverer's incinerator and HPU; and the emissions from the proposed onshore warehouse's oil-burning heater. EPA believes these scenarios are fully representative of the emissions from the drilling operations Shell will conduct in the Beaufort Sea during the July to December drill season.

In addition, a helicopter will be utilized to rotate the work crews. A maximum of three trips per day are expected. Because of the significant dispersion that occurs as a result of the helicopter's horizontal rotors, air quality modeling was not performed for the helicopter takeoffs and landings. Emissions associated with the helicopter are not expected to contribute to a violation of the NAAQS or noncompliance with PSD increments.

Table 5-5: Operating Scenarios

OPERATING SCENARIOS MODELED		DESCRIPTION
Base		Drilling by the Discoverer, deployment of the ice breaker OSR fleets to their standard positions, and resupply ship/barge and tug activities.
Other Operating Scenarios	1. Bow Washing	Anchor handler approaches Discoverer's bow to break ice accumulated there; concurrent with Base.
	2. Anchor Setting and Retrieval	Anchor setting and retrieval; most Discoverer sources not in operation.
	3. Discoverer 15 Degree Rotation	Discoverer realignment with wind; concurrent with Base.
	4. Ice Breaker and Anchor Handler Resupply	Ice breaker or anchor handler approach to transfer supplies and personnel; concurrent with Base.
	5. Nanuq Refueling	Oil spill recovery main ship, the Nanuq, approaches and connects a fuel line to the Discoverer to transfer fuel to it.
	6. Alternative Incinerator Use Options	Base scenario runs both HPU engines. This scenario considers other possible combinations of HPU engine usage and incinerator usage.
	7. Other Potential Operating Scenarios	Considers six possible ice management fleet configurations where support vessels could come closer to the Discoverer than in the base case.
	8. Warehouse Modeling	Analyzes impacts from the onshore warehouse

OPERATING SCENARIOS MODELED		DESCRIPTION
		heating unit.
	9. Tanker Modeling	Analyzes impacts from the tanker, which operates beyond 25 miles from the Discoverer.

Reference: Shell Beaufort Permit Application 01/18/10

5.2.6 Air Quality Model

In its air quality analysis, Shell used a non-guideline model called ISC3-PRIME, version 04269 (EPA 08/26/04 ISC3-Prime), to predict the maximum concentrations downwind of the hulls of the vessels. No site-specific over-ocean meteorological data was available in the Beaufort Sea. Without meteorological data, EPA's guideline model, AERMOD, could not be used. EPA believes ISC3-PRIME, a former EPA guideline dispersion model, is an appropriate model for determining the air quality impacts from the Discoverer and the Associated Fleet. It can model multiple emission sources and multiple source types, it can account for the wake effects from structures near emission points, it can accommodate a set of screening meteorological data, and it has been evaluated under Arctic conditions (EPA 06/03 AERMOD). EPA believes that ISC3-PRIME, using a screening meteorological dataset, will provide conservative estimates of the project's impacts. Therefore, EPA approved the use of ISC3-PRIME pursuant to Section 3.2 in 40 C.F.R. 51, Appendix W for use in evaluating Shell's permit application and air impact analysis.

As provided in 40 C.F.R. 52.21(l)(2), EPA is requesting public comment on the suitability of the ISC3-PRIME model in the ambient air quality impact analysis for this permitting action.

5.2.7 Meteorology

Because meteorological data representative of the open Beaufort Sea was not available, Shell used screening meteorology to predict worst-case ambient air impact concentrations from its exploratory drilling program. The use of screening meteorology typically results in a conservative analysis because it assumes a range of conditions conducive to high ambient pollution impacts, which may or may not be likely to occur frequently in the modeled domain.

Meteorological conditions from EPA's SCREEN3 model, consisting of 54 hours of wind speed, stability, temperature and mixing height combinations and a single wind direction (east to west), was input to ISC3-PRIME in Shell's analysis (EPA 10/92 Screening Procedures). The Discoverer pivots to face into the wind at all times, so the single wind direction is appropriate.

The SCREEN3 model employs a default ambient temperature of 293 Kelvin (K) (i.e., 19.85 degrees centigrade or 67.73 ^{o}F) to predict ambient air quality concentration impacts. After considering temperatures measured at Barrow, Alaska (Shell Beaufort Permit Application 1/18/10 Section 5.1.2), Shell modified the screening meteorology by using a lower, more representative ambient temperature of 261.1 K (-12 degrees centigrade or 10.3 ^{o}F).

Exhibit 5
AEWC & ICAS

5.2.8 Scaling Factors

Using a SCREEN3 meteorological data file, ISC3-PRIME can only provide one-hour concentration values. Scaling factors, as recommended by EPA, are simple multipliers used to estimate modeled concentrations at longer averaging periods (EPA 10/92 Screening Procedures). A range of scaling factors is suggested in EPA's document, but for this analysis, EPA recommended that Shell use the upper end scaling factors because of the expected wind persistence over the Beaufort Sea and the wake effects caused by vessel structures. See Table 5-6.

Table 5-6: Scaling Factors

Averaging Period	Scaling Factor
3-Hour	1.0
8-Hour	0.9
24-Hour	0.6
Annual Average	0.1

5.2.9 Ambient Air Definition

Ambient air is defined as "…that portion of the atmosphere, external to buildings, to which the general public has access" 40 C.F.R. § 50.1(e). Consistent with this definition, ambient air begins at and extends outward from the edge of the Discoverer and each vessel in the Associated Fleet. Similarly, ambient air begins at the exterior walls of the planned warehouse.

5.2.10 Urban/Rural Area Determination

The exploratory drilling operations will occur at 53 lease blocks in the Beaufort Sea, between Prudhoe Bay and Kaktovik, Alaska (Shell Beaufort Permit Application 01/18/10). The drilling operations occurring well out to sea are considered to be in a rural area for dispersion modeling. Shell may operate a combustion source to heat a warehouse at a coastal location, most likely in Barrow or Deadhorse, Alaska. In addition, other emission sources in the vicinity of Deadhorse and Badami, Alaska, will be included in the air quality analysis. The coastal region is also considered a rural area. Auer 1978.

5.2.11 Building Downwash/Wake Effects

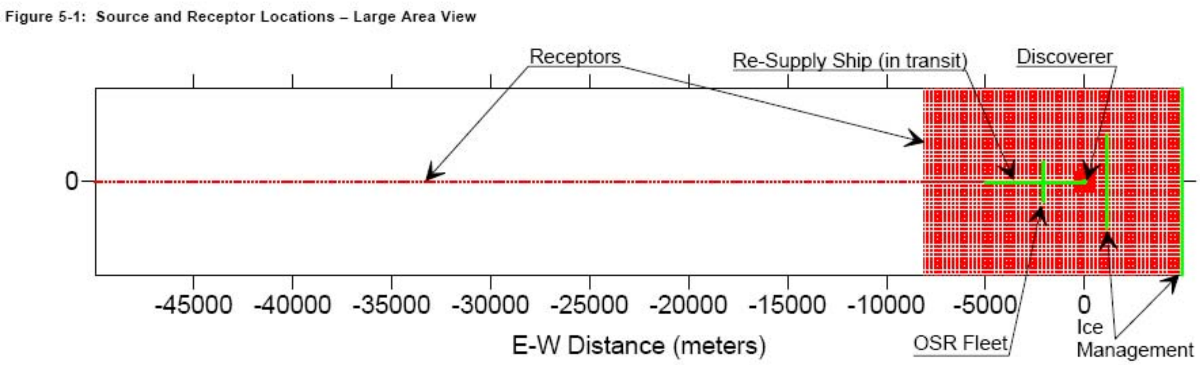
The Building Profile Input Program for PRIME (BPIPPRM) (EPA 4/21/04 User's Guide) calculates direction-specific building dimensions for input into ISC3-PRIME. These dimensions are used by the model to account for building downwash and wake effect which result from the effects of airflow around large structures near emission points. The stack location and height for each of the exhaust stacks above the water surface, along with the corner locations and structure height above the water surface of the Discoverer's main deck, its three above-deck structures, and the resupply ship's structures were input into BPIPPRM. Shell included the resulting direction-specific building dimensions in its modeling analysis. Similarly, the dimensions of the onshore warehouse structure were input into BPIPPRM and included in the modeling of this combustion source.

5.2.12 Receptors Location

A Cartesian coordinate system was used by Shell to define its primary modeling domain and covering all its overwater drilling and support operations. See Figure 5-2. Surface elevations were set to 0.0 meters. The center of the main 13 kilometer by 10 kilometer receptor grid is the exploratory drill hole location below the anchored Discoverer. Receptors in this grid are spaced every 100 meters.

There are several receptor grids within and extending out from the primary grid. The first grid consists of receptor points around the hull of the Discoverer and the resupply ship. These points, which define ambient air for the Discoverer, are spaced every ten meters. The second grid, a square, extends from the center of the Discoverer out to a distance of 500 meters. Receptor points in this area are at 25-meter intervals. Starting at the stern of the Discoverer is the elongated third receptor grid of approximately 50000 meters by 30 meters. There are three long rows of receptors (shown as one line extending to the left in Figure 5-2) along the centerline of the Discoverer and 15 meters to either side of the centerline. These receptors extend to a distance of 50000 meters downwind, with the receptor points at 25-meter intervals to a distance of 8000 meters downwind, and at 100-meter intervals between 8000 and 50,000 meters downwind. Figure 5-2 also shows the positioning of lines which describe the support vessels' movement relative to the Discoverer.

Figure 5-2: Modeling Domain and Receptor Points



5.2.13 Volume Source Representation for Vessels

Because there are no established procedures to model underway ship emissions, the support vessels were modeled as lines of volume sources representing their typical operating patterns. EPA requested that Shell model each known possible vessel of the ice breaker and OSR fleet as point sources, taking into account building wake effects, in order to determine the plume rise from the vessel stack emissions. Shell used the SCREEN3 model with D stability and a wind speed of 20 meters per second, in accordance with EPA's recommendation. The lowest plume rise calculated by SCREEN3 was used to establish the release height of the volume sources representing the vessels. Following the guidance contained in the ISC3 model user's guide (EPA 09/95 ISC3), the initial lateral dimension (sigma-yo) was calculated based on the vessel lengths and volume source separation distances, and the initial vertical dimension (sigma-zo) of the volume sources was calculated based on the height of the vessels.

To model the OSR fleet and the ice management fleet, a set of volume sources was placed along a line perpendicular to the Discoverer. A 9.6-kilometers line set 4.8 kilometers from the Discoverer represented the typical back and forth motion of the primary ice breaker breaking ice upwind of the Discoverer. A 4.8-kilometers line set 1 kilometers upwind of the Discoverer represented the anchor handler/ice management ship. A 2-kilometers line set 3 kilometers downwind of the Discoverer represented routine training exercises of the OSR fleet. All three of these lines are placed at the nearest distances to the Discoverer that the fleets would approach during normal base case operations.

In accordance with the ISC3 model user's guide (EPA 09/95 ISC3), volume sources, sized based on the vessels' dimensions, were placed adjacent to one another along the lines. Total vessel emissions were evenly distributed among the volume sources in the line for each fleet. Volume sources were similarly used to represent the approach of the resupply ship, which is included in the base operating scenario, and other vessel approaches within the other operating scenarios. The volume sources representing the ice breaker fleet, anchor handler, resupply ship, and OSR fleet were then modeled concurrently with the Discoverer's onboard emission units as they operate in the Beaufort Sea. EPA believes this approach will result in conservative concentration predictions.

5.2.14 Source Locations and Source Parameters

The modeled locations for operations during the base scenario and source parameters of the emission units on the Discoverer and Associated Fleet appear in Table 5-7. The x-coordinate and y-coordinates are based on an origin at (0, 0) meters at the drill hole as depicted in Figure 5-2. In general, the ice breaker and the anchor handler will operate no closer than 4800 meters and 1000 meters upwind of the Discoverer respectively, during drilling operations. When not performing training exercises, the OSR fleet will maintain a position several miles away from the Discoverer, but for the modeling, the OSR fleet is assumed to operate downwind of the Discoverer at a distance of 3000 meters.

Parameters needed for modeling point sources include stack height, stack gas exit temperature, stack gas exit velocity and inside stack diameters. Modeling volume sources requires release height, initial sigma-y and initial sigma-z.

Table 5-7: Base Operating Scenario – Location and Stack Parameters

Emission Units or Sources	Source Type	Location [a]		Stack Parameters			
		x (m)	y (m)	Height (m)	Temperature (K)	Velocity (m/sec)	Diameter (m)
Generator Eng [a,b,c]	Point	57.6	0.8	17.40	710.00	32.89	0.32
MLC Comp Eng [a,b,c]	Point	5.5	8.6	13.10	699.80	40.00	0.21
HPU Eng [a,b,c]	Point	-17.5	10.6	10.70	699.80	40.00	0.18
Cementing Eng	Point	-1.5	12.6	10.70	800.00	46.60	0.18
Port Crane Eng [a,b,c]	Point	17.5	11.6	18.29	672.00	20.10	0.25
Stbd Crane Eng [a,b,c]	Point	-26.4	-10.7	18.29	672.00	20.10	0.25
Heat Boiler [a,b,c]	Point	57.8	-2.18	17.40	478.00	7.34	0.46
Log Winch Eng [a,b,c]	Point	24.2	0.8	13.11	710.90	52.97	0.10
Incinerator [a,b,c]	Point	-35.5	10.6	7.01	623.00	10.00	0.46
Over Land Heater [d]	Point	-26.4	-10.7	7.62	478.00	6.60	0.46
Kilabuk supply ship	Point	-26.5	-66.4	15.24	700	40	0.18
				Height (m)	Sigma-y_o (m)	Sigma-z_o (m)	
Ice Breaker #1 [a,c,e]	Volume	[d]	[d]	25.22	46.51	9.21	
Ice Breaker #2 [a,c,f]	Volume	[e]	[e]	25.22	46.51	9.21	

Emission Units or Sources	Source Type	Location [a]		Stack Parameters			
		x (m)	y (m)	Height (m)	Temperature (K)	Velocity (m/sec)	Diameter (m)
Oil Spill ResponseK [a,c,g,h]	Volume	[f]	[f]	3.38	5.4	1.42	
Oil Spill ResponseN [a,c,h,i]	Volume	[g]	[g]	17.55	42.3	6.38	
Kilabuk in transit	Volume	[j]	[j]	15.24	29.1	6.38	

Reference: Shell Beaufort Permit Application 01/18/10

a. Origin of coordinate system is the drill hole location below the Discoverer.
b. Discoverer emission units. Single locations are used to represent similar emission units (i.e., six generator engines, three MLC compressor engines, two HPU engines, two cementing engine units, two heat boilers and two logging winch engines.
c. Stack height or release height is given as height above the surface or water line.
d. The receptor grid and coordinate system used to model the onshore warehouse heater is different from that used by the over water emission sources. The origin is at the stack location.
e. Ice Breaker #1 is located approximately 5000 meters upwind of the drill hole location. Ice Breaker #1 is represented by 96 volume sources.
f. Ice Breaker #2 is located approximately 1000 meters upwind of the drill hole location. Ice Breaker #2 is represented by 48 volume sources.
g. Oil Spill ResponseK is located about 2000 meters downwind of the drill hole location. This source represents the work boats.
h. Oil Spill ResponseK is 172 volumes and Oil Spill ResponseN is 22 volumes.
i. Oil Spill ResponseN is located about 2000 meters downwind of the drill hole location. This source represents the Nanuq, the Arctic Endeavor Barge and the Point Barrow Tug.
j. The Kilabuk transit path is split into 80 volumes, about 70 meters from the ship's side.

5.2.15 Full Impact Analysis

A full impact analysis, addressing both the PSD increments and the NAAQS, was performed for NO_2 and PM_{10}. A NAAQS analysis was performed for $PM_{2.5}$. The Shell project's modeled SO_2 and CO impacts were below significant impact levels; therefore a full impact analysis is not required.

5.2.16 Other Emission Sources

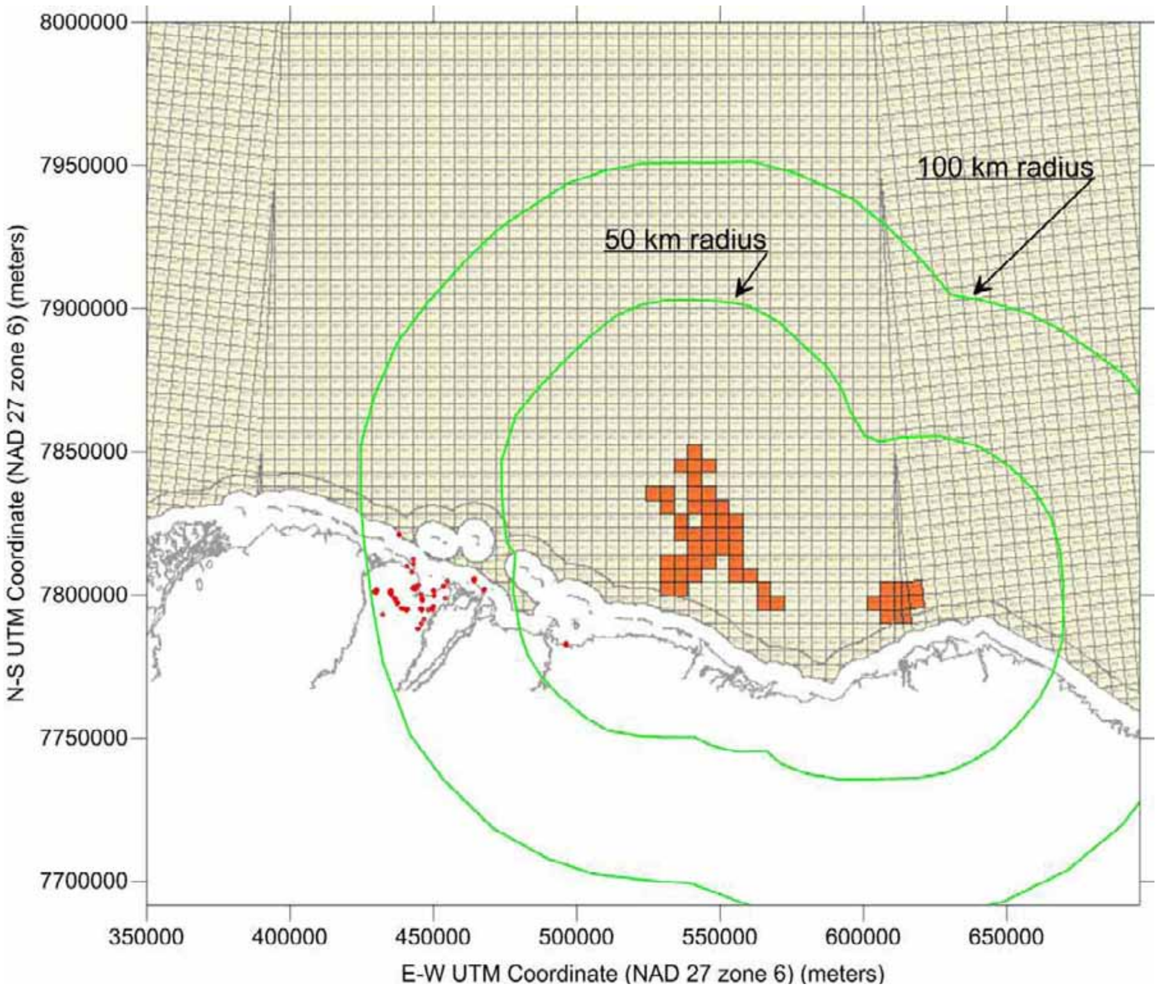
There are a number of facilities onshore within 100 kilometers of Shell's Beaufort Sea lease blocks. Most are further than 50 kilometers from the nearest lease block. The onshore sources which were evaluated for the full impact analysis are listed in Table 5-8, and depicted by the red dots in Figure 5-3. These facilities were modeled in a separate analysis and its results were combined with the results of the Shell offshore project's modeling. See Section 5.2.20.

Table 5-8: Onshore Facilities

		Facility Wide Emissions (tpy)		
Company	**Facility**	**NO_X**	**SO_2**	**PM_{10}**
BP	Badami	277.9	66.6	11.6
BP	Base Operations Center	1165.0	171.0	37.0
BP	Central Compression Plant	14238.0	147.0	347.0
BP	Central Gas Facility	10968.0	125.0	305.0
BP	Endicott Production Facility[1]	3594.0	539.0	63.0
BP	Flow Station #1	2872.0	35.0	84.0
BP	Flow Station #2	3663.0	83.0	91.0
BP	Flow Station #3	4235.0	42.0	100.0
BP	Gathering Center #1	4912.0	48.0	107.0
BP	Gathering Center #2	2370.0	38.0	84.0
BP	Gathering Center #3	2873.0	33.0	69.0
BP	Lisburne Production Center	2241.0	263.0	57.0
BP	Northstar Production Facility	562.0	56.5	331.0
BP	PBU Central Power Station	6110.0	63.0	150.0
BP	Prudhoe Bay Operations Center	231.0	51.5	45.8
BP	Seawater Injection Plant East	2175.0	20.0	42.0
BP	Seawater Treatment Plant	395.0	28.0	35.0
BP	Transportable Drilling Rigs	1386.7	145.6	56.7
Alyeska	TAPS Pump Station 001	773.0	39.0	122.0
Alaska Interstate	Deadhorse Soil Remediation Unit	107.0	162.8	13.5
Haliburton	Deadhorse Facility	249.0	1.5	2.3
TDX	Deadhorse Power Plant	246.0	9.0	17.0
Total		**65644.0**	**21683.0**	**2171.0**

Reference: Shell Beaufort Permit Application 01/18/10
[1] Endicott Production Facility emissions include the Liberty Expansion

Figure 5-3: Beaufort Sea OCS Lease Blocks and Other Onshore Facilities



5.2.17 Onshore Meteorological Data

For the onshore source modeling, Shell used five years of representative local onshore meteorological data from Badami, Alaska, dated 1991-1995.

5.2.18 Onshore Modeling Receptors

In addition to its original receptor grids, Shell modeled a set of receptors covering a region 50 kilometers from the center of each lease block. These receptors were one kilometer apart. Model results for the onshore sources only included receptors where the lease block grid overlapped with receptors within a 50 kilometer radius of each of the onshore sources. ISC3-PRIME model predictions are generally not used beyond 50 kilometers. Beyond that distance, the model's predictions are likely to be too conservative for regulatory use. Figure 5-3 above shows the 50 kilometers radius around Shell's lease blocks.

5.2.19 Short-Term Emissions

Shell was unable to obtain short-term emissions data for most of the onshore sources. Shell therefore performed a limited analysis with two sources for which short-term emissions data were available: BP Endicott Production Facility (BP Endicott) and BP Northstar Production Facility (BP Northstar). BP Endicott had the largest total SO_2 emissions of the onshore sources, and BP Northstar had the second-largest total PM_{10} emissions of the onshore sources. Shell's analysis showed that the two facilities' short-term impacts fell below the significant impact levels between 1 and 12 kilometers from the facilities. See Table 5-10. Since both facilities are over 50 kilometers from the nearest Shell lease block, the short term impacts from these facilities would be unlikely to contribute to an exceedance of the NAAQS or increment within Shell's significant impact area. With the exception of two sources with similar total PM_{10} emissions to BP Northstar, the other onshore sources have much lower annual total SO_2 and PM_{10} emissions than BP Endicott and BP Northstar. While a full analysis including short-term emissions from all sources would have been preferable, EPA believes that this limited analysis does indicate that short-term emissions from the onshore sources would not reasonably be expected to cause exceedances of the NAAQS or increments within Shell's significant impact areas.

Table 5-9: Short-Term Significant Impact Areas for Two Onshore Sources

Facility	Pollutant	Averaging Period	SIL (µg/m3)	Distance Exceeding SIL (km)	Max modeled value (µg/m3)
BP Endicott	SO_2	24-hour	5	11.4	21.69
		3-hour	25	1.6	55.94
BP Northstar	PM_{10}	24-hour	5	0.9	8.27

5.2.20 Combining Shell and Onshore Source Impacts

The emissions of the Shell project drilling sources were modeled with ISC3-PRIME and screening meteorology with a single wind direction, as in the preliminary analysis. The Shell project receptors were placed relative to the drill hole, but the actual physical location of the Discoverer could change depending on which lease block was under consideration. Since the onshore sources were modeled with full actual meteorological data and a set of receptors which was fixed in place, Shell needed to combine the results of the analyses to obtain conservative total concentrations. First, Shell compiled all the project modeled concentrations and sorted them by distance from the drill hole (center of modeling domain). The overall maximum concentrations were found either at the Discoverer's hull or near the Associated Fleet within a few kilometers of the Discoverer. Next, Shell determined the maximum concentration at each receptor distance, based on all the receptors at and beyond that distance. For a given distance, if a receptor further from the drill hole was found to have a higher concentration, then that higher concentration was used. This was done to cover any receptors which might have been off the plume centerline, where they would have had lower modeled concentrations than a centerline receptor at the same or greater distance. This analysis determined the maximum contribution from the project sources at varying distances from the drill hole. Finally, for each onshore source receptor, Shell determined the distance to the nearest possible lease block drill hole. The maximum concentration from the onshore sources at that receptor was then added to the maximum project contribution at that distance. (Shell Beaufort Permit Application 1/18/10 Section 7.2.5) This provided a conservative estimate of the total concentration which could be expected at that location if the Discoverer were drilling at the closest lease block.

5.2.21 Background Monitoring Data and Preconstruction Monitoring

Background monitoring data is used in conjunction with modeled predictions to determine if emissions from the project would cause or contribute to violations of NAAQS. For background air monitoring data in its permit application, Shell relied on data collected at a number of monitoring stations on the North Slope, as shown in Table 5-10. Figure 5-4 shows the location of the North Slope air monitoring stations. There is one station currently collecting data for the Shell Beaufort Sea PSD application, located at Badami, Alaska.

The Badami monitoring station began collecting NO_2, $PM_{2.5}$ and meteorological data on August 15, 2009. (Valid $PM_{2.5}$ data collection began on August 20, 2009.) EPA has determined that $PM_{2.5}$ data collected from August 20, 2009 to December 15, 2009 is appropriate for use as representative background air quality data for this permitting action.

The available $PM_{2.5}$ data from Badami covers a roughly four month period which is within Shell's 168-day drilling season between July 1 and December 31. We expect to receive $PM_{2.5}$ data from Badami for the period December 15 through December 31, 2009, during the public comment period for this permit, after which the data set is expected to meet the four-month requirement for acceptability under 40 C.F.R. 52.21(m)(1)(iv). $PM_{2.5}$ data from July 1 to August 15, 2009, is not available at Badami, so the data will not cover the entire drilling season. It is expected that local contributions of PM_{10} and $PM_{2.5}$ from blowing dust would be highest in the summer months, while contributions from local fuel-burning heating units would be higher in the fall and winter months. No information is available on the seasonality of any particulate matter transported from overseas. EPA expects that actual background levels of pollution several miles offshore in the vicinity of Shell's planned exploratory drilling operations are likely to be lower than the levels recorded onshore, where monitors are affected by local industrial and residential sources.

Figure 5-4: North Slope Monitoring Stations

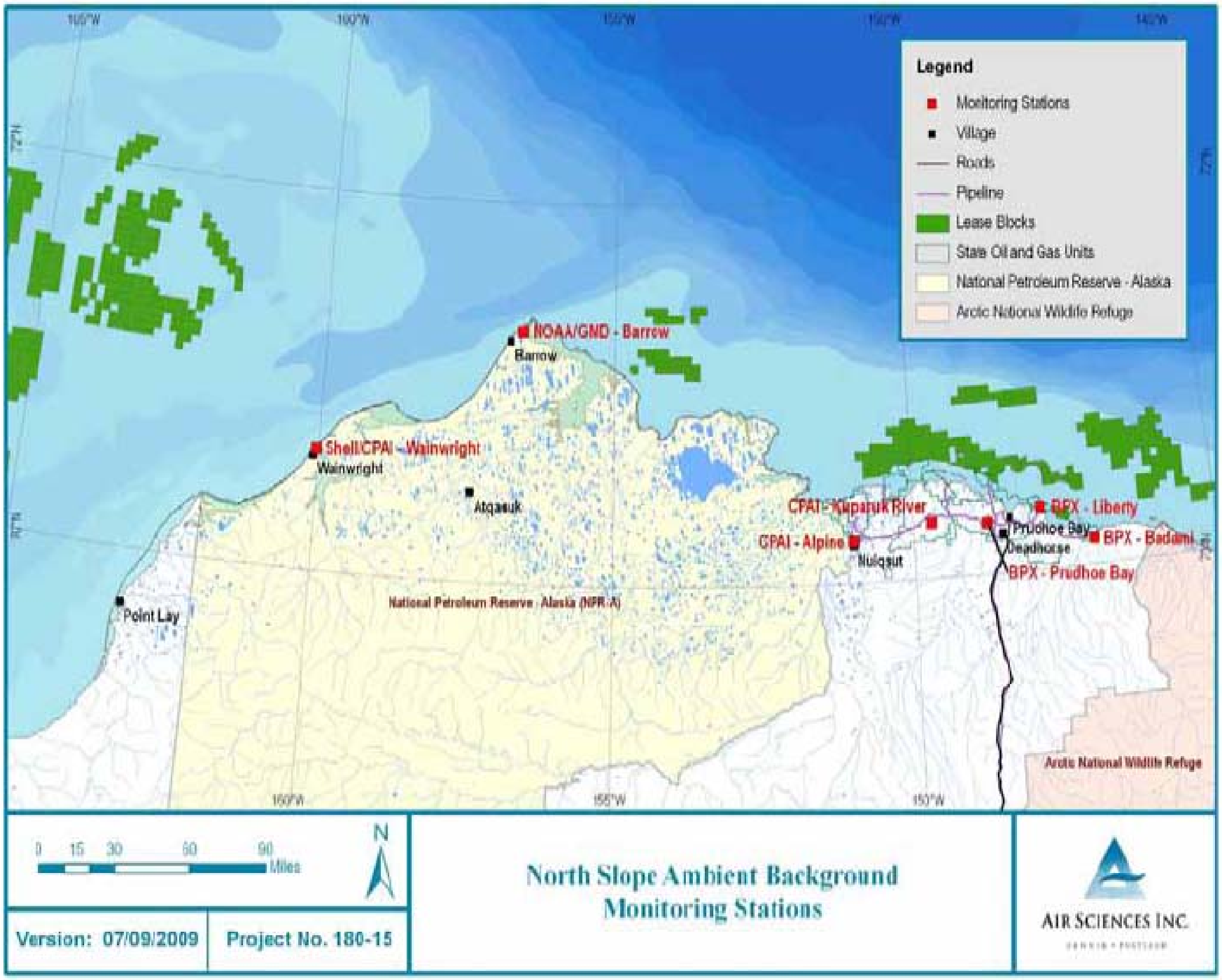


Table 5-10: North Slope Stations

Company Location	Station	Data Dates	Maximum Measured Concentrations (µg/m³)							
			PM_{10}		NO_2	CO		SO_2		
			24-hr	Annual	Annual	1-hr	8-hr	3-hr	24-hr	Annual
BPXA - Badami	ANSER	1999	7.9	1.8	3.0	---	---	9.8	7.2	2.6
BPXA - Liberty	Liberty	02/2007-01/2008	---	---	11.3	1,749	1,097	41.6	13.0	2.6
BPXA – Prudhoe Bay	A Pad	2006, 2007	---	---	10.5	---	---	41.6	33.8	2.1
BPXA – Prudhoe Bay	Central Compressor Plant	2006, 2007	55.1	7.5	19.7	---	---	28.6	23.4	2.2
CPAI -	Nuiqsut	2003,	54.0[a]	6.9[a]	17.3	---	---	18.2	7.8	0.2

Exhibit 5
AEWC & ICAS

Company Location	Station	Data Dates	Maximum Measured Concentrations (µg/m^3)							
			PM_{10}		NO_2	CO		SO_2		
			24-hr	Annual	Annual	1-hr	8-hr	3-hr	24-hr	Annual
Alpine		2004, 2005								
CPAI – Kuparuk River	DSIF	06/2001-06/2002	60	6	6	1,100	600	36.0	16.0	0.0
Shell/ CPAI - Wainwright	Wainwright[b]	11/2008-08/2009	114	4.0	1.9	1,051	949	18.0	10.5	0.0

Reference: Shell Beaufort Permit Application 01/18/10

a. Local emissions sources such as blowing dist from nearby river channels elevate ambient PM_{10} concentrations at Nuiqsut which is not representative of remote offshore locations; PM_{10} data presented is from the most recent annual reports available to Alaska DEC (Station Year 6: March 2004 – April 2005) and does not include hours associated with naturally occurring forest fires and wind blown dust events.

b. The maximum monthly data are provided as the annual average concentrations from this station until a year's worth of data are available at the station.

For background values in the NAAQS analysis, Shell proposed to use data from the BPX Liberty monitor from 2007-2008 for NO_2, CO, and SO_2, and data collected in 2006 and 2007 at the BPX Prudhoe Bay Central Compressor Plant monitor for PM_{10}. EPA agrees that this data was acceptable. $PM_{2.5}$ values were to be taken from the Badami monitor. In its application (Shell Beaufort Permit Application 01/18/10), Shell proposed a 24-hour $PM_{2.5}$ background value of 8 ug/m^3 and an annual $PM_{2.5}$ background value of 2 ug/m^3. When the Badami data was complete through December 15, 2009, the maximum 24-hour $PM_{2.5}$ value recorded was 10 ug/m^3. EPA believes that this conservative value should be used as the 24-hour background $PM_{2.5}$ value for this project. Table 5-11 lists the background concentrations which are used in the NAAQS results calculations tabulated in Section 5.2.23 for both the offshore and onshore sources.

Table 5-11: Background Estimates for NAAQS Analysis

Pollutant	Averaging Time	Measured Concentration(µg/m^3)	Data Source
NO_2	Annual	11.3	BPX Liberty 02/07-01/08
PM_{10}	24-hour	55.1	BPX Prudhoe Bay 07
	Annual	7.5	BPX Prudhoe Bay 07
$PM_{2.5}$	24-hour	10.0	Badami 8/09-12/09
	Annual	2.0	Badami 8/09-12/09
CO	1-hour	1749.0	BPX Liberty 02/07-01/08
	8-hour	1097.0	BPX Liberty 02/07-01/08

Pollutant	Averaging Time	Measured Concentration(μg/m^3)	Data Source
SO_2	3-hour	41.6	BPX Liberty 02/07-01/08
	24-hour	13.0	BPX Liberty 02/07-01/08
	Annual	2.6	BPX Liberty 02/07-01/08

Reference: Shell Beaufort Permit Application 01/18/10

Shell is also relying on data from the Badami and other local sites to fulfill the preconstruction monitoring requirement of 40 C.F.R. § 52.21(m). As shown in Table 5-12, preconstruction monitoring is required for NO_2 and PM_{10} because the predicted highest concentration for these air pollutants emitted by the Discoverer and its associated fleet exceed the significant monitoring thresholds for these pollutants. Preconstruction monitoring is also required for ozone because emissions of NO_2 and VOC exceed 100 tons per year. Several of the existing North Slope stations have collected ozone data, including BPX Prudhoe Bay Central Compressor Plant (2007). Available monitoring data shows that the NAAQS are being met.

Table 5-12: Preconstruction Significant Monitoring Levels

Air Pollutant	Averaging Time	Predicted Offshore (μg/m^3)	Significant Monitoring Level (μg/m^3)
Sulfur Dioxide (SO_2)	24-Hour	3.2	13
Nitrogen Dioxide (NO_2)	Annual	19.7	14
Carbon Monoxide (CO)	8-Hour	458.0	575
Particulate Matter equal to or less than 10 microns (PM_{10}) [a]	24-Hour	20.7	10

a. EPA has not promulgated a $PM_{2.5}$ monitoring threshold so preconstruction monitoring has been required for $PM_{2.5}$.

5.2.22 Results of Increment Demonstration

All of the modeled operating scenarios for the Discoverer and its Associated Fleet resulted in predicted concentration impacts below the Class II increments. Table 5-13 shows the predicted maximum concentrations for the base and other operating scenarios compared to the PSD increments for Class II areas. The peak receptors were near the Discoverer, well outside the onshore sources' 50 kilometer modeled range. The onshore sources' impacts beyond 50 kilometers were assumed to be zero. In this case, the actual modeled concentrations just short of 50 kilometers were extremely small--about 0.00001 μg/m^3. Short-term concentrations for the onshore sources were not calculated due to lack of short-term emissions information. A limited analysis showed that the contributions from the largest onshore sources would fall below the significant impact levels quickly, within a few kilometers of the onshore source, and over 50 kilometers from the Discoverer. See Section 5.2.19.

Table 5-13: PSD Increment Modeling Results

Pollutant	Averaging Period	PSD Class II Increment µg/m^3)	Project Contribution at Peak Receptor (µg/m^3)	Onshore Source Contribution at Peak Receptor (µg/m^3)	Increment Exceeded?
NO_2	Annual	25	19.7	0	No
PM_{10}	24-Hour	30	20.7	NA[a]	No
	Annual	17	1.1	0	No
SO_2	3-Hour	512	25	NA[1]	No
	24-Hour	91	3.2	NA[1]	No
	Annual	20	0.1	0	No

a Short term emissions were not modeled for the onshore sources.

5.2.23 Results of NAAQS Demonstration

All of the modeled operating scenarios for the Discoverer and its Associated Fleet resulted in predicted total concentration impacts, including existing background data, below the level of the NAAQS. Table 5-14 summarizes the maximum predicted total impacts for the base operating scenario. Tables 5-15 to 5-24 show the results for the operating scenarios. The modeling results show that the emissions associated with the proposed permit are not expected to cause or contribute to a violation of the applicable NAAQS.

Table 5-14: NAAQS Modeling Results

Pollutant	Averaging Period	Concentration at Peak Receptor (µg/m^3)				NAAQS (µg/m^3)	Percent NAAQS
		Without Background	Back-ground	Onshore Source Contribution at Peak Receptor	Total with Background		
NO_2	Annual	19.7	11.3	0	31.0	100	31%
$PM_{2.5}$	24-Hour	19.2	10	NA	29.2	35	83%
	Annual	1.1	2	0	3.1	15	20.6%
PM_{10}	24-Hour	20.7	55.1	NA	75.8	150	50.5%
	Annual	1.1	7.5	0	8.6	---	---
SO_2	3-Hour	25.0	41.6	NA	66.6	1,300	5.1%

Pollutant	Averaging Period	Concentration at Peak Receptor (μg/m³)				NAAQS (μg/m³)	Percent NAAQS
		Without Background	Back-ground	Onshore Source Contribution at Peak Receptor	Total with Background		
	24-Hour	3.2	13.0	NA	16.2	365	4.4%
	Annual	0.01	2.6	3.38	6.0	80	7.5%
CO	1-Hour	1227.1	1750	NA	2977.1	40,000	7.4%
	8-Hour	457.5	1070	NA	1527.5	10,000	15.3%

Reference: Shell Permit Beaufort Application 01/18/10

Scenario #1 Bow Washing

When ice builds up at the bow of the Discoverer, the anchor handler approaches and moves back and forth to create waves that break up the ice and move it away from the Discoverer. This activity is expected to take about 30 minutes. The anchor handler's main engines will operate at a reduced power setting during bow washing, but its generators and boilers were assumed for worst-case modeling purposes to operate at full load. The results of Shell's analysis of this operating scenario are given in Table 5-17.

Table 5-15: Operating Scenario #1, Bow Washing Predicted Results

Air Pollutant	Averaging Period	Distance Exceeding SIL	Peak Predicted Concentration (μg/m³)	Back-Ground (μg/m³)	Total [a] (μg/m³)	NAAQS (μg/m³)	Percent of NAAQS
PM_{10} [b]	24-Hour	41.8	19.8	55.1	74.9	150	50%
$PM_{2.5}$	24-Hour	NA	18.5	10.0	28.5	35	81%
CO	1-Hour	0	789.5	1749.0	2538.5	10000	25%
	8-Hour	0	376.1	1097.0	1473.0	40000	4%
SO_2	3-Hour	0	24.8	41.6	66.4	1300	5%
	24-Hour	0	1.3	13.0	14.3	365	4%

Reference: Shell Beaufort Permit Application 01/18/10.

a. The sum of the predicted impact and existing background.

b. Bow washing takes about 30 minutes and was modeled as lasting one hour, concurrent with normal drilling operations. No annual averages were calculated.

Scenario #2 Anchor Setting and Retrieval

This scenario reflects Shell's modeled analysis during the anchor setting and retrieval procedures beginning when the first anchor is set or released. (Shell Beaufort Permit Application 01/18/10

Sections 3.2.1 and 5.4.2) Several volume sources were placed around the Discoverer to simulate the anchor handler's changing positions during the procedure. Drilling is not expected to occur during this process, so several of the Discoverer's emission sources are not modeled, and the anchor handler's main engines are assumed to be at 20% load, but the anchor handler's generators and heaters are assumed to operate at full load. The results of Shell's analysis are given in Table 5-18.

Table 5-16: Operating Scenario #2, Anchor Setting and Retrieval Predicted Results

Air Pollutant	Averaging Period	Distance Exceeding SIL	Peak Predicted Concentration ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10} [b]	24-Hour	37.5	19.6	55.1	74.7	150	50%
$PM_{2.5}$	24-Hour	NA	18.3	10.0	28.3	35	81%
CO	1-Hour	0	619.7	1749.0	2368.7	10000	24%
	8-Hour	0	363.9	1097.0	1460.9	40000	4%
SO_2	3-Hour	0	24.4	41.6	66.0	1300	5%
	24-Hour	0	1.3	13.0	14.3	365	4%

Reference: Shell Beaufort Permit Application 01/18/10.
a. The sum of the predicted impact and existing background.
b. Anchor setting and retrieval takes no more than 18 hours. No annual averages were calculated.

Scenario #3 Discoverer 15 Degree Rotation

The Shell modeling assumes that the Discoverer always faces its bow into the wind. This is important for effective ice management. The Discoverer can rotate about its drilling mechanism while continuing to drill. This process uses equipment powered by generators which are already accounted for in the Base Operations scenario. No increase in emissions or change in operations from the Base Operations scenario is anticipated. The ship's orientation is constantly monitored and adjusted, so that it is expected to be oriented within 15 degrees of the wind at all times, and turning the ship to face the wind is expected to be less than an hour. Therefore, Shell did not perform a separate model run for the turning procedure's emissions and the Shell modeling did not separately account for times when the ship is at an angle to the wind.

Scenario #4 Ice Breaker and Anchor Handler Resupply

When the ice breaker fleet needs supplies, personnel, or assistance from the Discoverer, either the primary ice breaker or the anchor handler will approach the Discoverer, dock briefly, and then return to the normal ice management location. The approaching ship would operate at reduced power during this scenario, but the ships' generators, boilers and incinerators are assumed to operate at maximum, for worst-case conditions. A series of volume sources were used to represent the approach of the ships, and an additional volume source was placed beside the Discoverer to represent the ship's emissions while docked. Two separate modeling runs were performed, to account for the two ships' differing emissions and travel times. The results of these analyses are given in Tables 5-19 and 5-20.

Table 5-17: Operating Scenario #3, Ice Breaker Resupply Results

Air Pollutant	Averaging Period	Distance Exceeding SIL	Peak Predicted Concentration ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10} [b]	24-Hour	40.9	20.7	55.1	75.8	150	51%
$PM_{2.5}$	24-Hour	NA	19.2	10.0	29.2	35	83%
CO	1-Hour	0	733.5	1749.0	2482.5	10000	25%
	8-Hour	0	381.3	1097.0	1478.3	40000	4%
SO_2	3-Hour	0	24.6	41.6	66.2	1300	5%
	24-Hour	0	1.3	13.0	14.3	365	4%

Reference: Shell Beaufort Permit Application 01/18/10
a. The sum of the predicted impact and existing background.
b. Total travel and idling during ice breaker resupply takes about two hours. No annual averages were calculated.

Table 5-18: Operating Scenario #3, Anchor Handler Resupply Results

Air Pollutant	Averaging Period	Distance Exceeding SIL	Peak Predicted Concentration ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10} [b]	24-Hour	40.6	18.9	55.1	69.4	150	46%
$PM_{2.5}$	24-Hour	NA	18.5	10	28.5	35	81%
CO	1-Hour	0	1227.1	1749	2976.1	10000	30%
	8-Hour	0	373.0	1097	1470.0	40000	4%
SO_2	3-Hour	0	25.0	41.6	66.6	1300	5%
	24-Hour	0	1.3	13.0	14.3	365	4%

Reference: Shell Beaufort Permit Application 01/18/10
a. The sum of the predicted impact and existing background.
b. Total travel and idling during anchor handler resupply takes about one hour. No annual averages were calculated.

Scenario #5 Nanuq Refueling

When the Discoverer requires fuel, a vessel will approach and transfer fuel. The main oil spill recovery ship, the Nanuq, is the most likely ship to perform this task. The process may take up to eight hours, and the Nanuq will use its propulsion engines to maintain its position beside the Discoverer while the two vessels are connected by the fuel line. Shell's modeling assumed that the Nanuq would operate at normal power levels, which gives a worst-case estimate of the refueling emissions. Eight volume sources were used to represent the Nanuq during refueling, both to give the Nanuq flexibility in positioning and to account for its motion during the refueling process. The results of Shell's modeling for this operating scenario are given in Table 5-21.

Table 5-19: Operating Scenario #5, *Nanuq* Refueling Predicted Results

Air Pollutant	Averaging Period	Distance Exceeding SIL	Peak Predicted Concentration (µg/m^3)	Back-Ground (µg/m^3)	Total [a] (µg/m^3)	NAAQS (µg/m^3)	Percent of NAAQS
PM_{10}	24-Hour	42.2	20.7	55.1	75.8	150	51%
$PM_{2.5}$	24-Hour	NA	19.1	10.0	29.1	35	83%
CO	1-Hour	0	653.4	1749.0	2402.4	10000	24%
	8-Hour	0	457.5	1097.0	1554.5	40000	4%
SO_2 [b]	3-Hour	0	24.4	41.6	66.0	1300	5%
	24-Hour	0	1.3	13.0	47.5	365	4%

Reference: Shell Beaufort Permit Application 01/18/10
a. The sum of the predicted impact and existing background.
b. Refueling process can take up to eight hours. No annual averages were calculated

Scenario #6 Alternative Incinerator Use Options

Shell has asked for flexibility within its operating restrictions for the Discoverer's incinerator and hydraulic power unit (HPU) engines. The Base Operations scenario is maximum HPU usage and 300 pounds of waste throughput per day (lb waste/day) for the incinerator. For times when greater incinerator usage is necessary, Shell proposes to reduce usage of the HPU engines accordingly. The two alternative incinerator use options allow for 800 lb waste/day if only one HPU engine is running, or 1300 lb waste/day if neither HPU engine is running. The modeled impacts of these alternatives are shown in Table 5-22.

Table 5-20: Operating Scenario #6, Predicted Results for Alternative Incinerator Options

Air Pollutant	Averaging Period	Maximum Predicted Concentration (µg/m^3)		Back-Ground (µg/m^3)	Total [d] (µg/m^3)		NAAQS (µg/m^3)	Percent of NAAQS	
		Alt 1 [a]	Alt 2 [b]		Alt 1	Alt 2		Alt 1	Alt 2
PM_{10} [c]	24-Hour	19.4	19.4	55.1	74.5	74.5	150	50%	50%
		18.1	18.1	10	28.1	28.1	35	80%	80%

		Maximum Predicted Concentration (μg/m³)			Total [d] (μg/m³)			Percent of NAAQS	
$PM_{2.5}$	24-Hour								
SO_2	24-Hour	2.2	3.2	13.0	15.2	16.2	365	4%	4%

Reference: Shell Beaufort Permit Application 01/18/10

a. Alternative 1: 800 lb waste/day; one HPU engine running.
b. Alternative 2: 1300 lb waste/day; no HPU engines running.
c. Only 24-hour averages were calculated. Short-term emissions were modeled at maximum in the base operations modeling; increasing the amount of waste throughput allowed daily does not increase the maximum hourly emissions.
d. The sum of the predicted impact and existing background.

Scenario #7 Other Potential Operating Scenarios

The ice management vessels may sometimes need to move out of their standard icebreaking patterns, which may bring them closer to the Discoverer. Six additional fleet configurations were evaluated, in which either the anchor handler or the primary ice breaker would operate either directly to the side of the Discoverer, or 100 meters upwind, or 500 meters upwind. The results of these analyses are shown in Tables 5-23 and 5-24.

Table 5-21: Operating Scenario #7, Predicted Results for Six Alternative Ice Management Vessel Locations, Alternatives 1-3 (Anchor Handler)

Air Pollutant	Ave. Period	Peak Predicted Concentration (μg/m³)			Back-ground (μg/m³)	Total [e] (μg/m³)			NAAQS (μg/m³)	Percent of NAAQS		
		1 [a]	2 [b]	3 [c]		1	2	3		1	2	3
PM_{10} [d]	24-Hour	19.5	19.5	19.5	55.1	74.6	74.6	74.6	150	50%	50%	50%
$PM_{2.5}$	24-Hour	18.2	18.2	18.2	10.0	28.2	28.2	28.2	35	81%	81%	81%
CO	1-Hour	613.4	613.1	612.1	1749.0	2362.4	2362.1	2361.1	10000	24%	24%	24%
	8-Hour	358.1	357.9	356.9	1097.0	1455.1	1454.9	1453.9	40000	4%	4%	4%
SO_2	3-Hour	24.4	24.4	24.4	41.6	66.0	66.0	66.0	1300	5%	5%	5%
	24-Hour	1.3	1.3	1.3	13.0	14.3	14.3	14.3	365	4%	4%	4%

Reference: Shell Beaufort Permit Application 01/18/10

a. Anchor Handler near side of Discoverer.
b. Anchor Handler 100 meters upwind of Discoverer.
c. Anchor Handler 500 meters upwind of Discoverer.
d. No annual averages were calculated.
e. The sum of the predicted impact and existing background.

Table 5-22: Operating Scenario #7, Predicted Results for Six Alternative Ice Management Vessel Locations, Alternatives 4-6 (Ice Breaker)

Air Pollutant	Ave. Period	Peak Predicted Concentration ($\mu g/m^3$)			Back-ground ($\mu g/m^3$)	Total [e] ($\mu g/m^3$)			NAAQS ($\mu g/m^3$)	Percent of NAAQS		
		4 [a]	5 [b]	6 [c]		4	5	6		4	5	6
PM_{10} [d]	24-Hour	20.1	20.1	20.1	55.1	75.2	75.2	75.2	150	50%	50%	50%
$PM_{2.5}$	24-Hour	18.8	18.8	18.7	10	28.8	28.8	28.7	35	83%	83%	82%
CO	1-Hour	614.0	613.9	613.5	1749	2363.0	2362.9	2362.5	10000	24%	24%	24%
	8-Hour	358.6	358.6	358.2	1097	1455.6	1455.6	1455.2	40000	4%	4%	4%
SO_2	3-Hour	24.4	24.4	24.4	41.6	66.0	66.0	66.0	1300	5%	5%	5%
	24-Hour	1.3	1.3	1.3	13.0	14.3	14.3	14.3	365	4%	4%	4%

Reference: Shell Beaufort Permit Application 01/18/10
a. Ice breaker near side of Discoverer.
b. Ice breaker 100 meters upwind of Discoverer.
c. Ice breaker 500 meters upwind of Discoverer.
d. No annual averages were calculated.
e. The sum of the predicted impact and existing background.

Scenario #8 Warehouse Modeling

Shell plans to locate a warehouse at an onshore location (undecided) to support its drilling activities. The warehouse would most likely be located in Barrow or Deadhorse. Its only emissions would be from its heating system, and it would only be used during the drilling season. Shell performed a screening level modeling analysis to determine the potential impacts of the warehouse's heaters. The emissions of the heater were estimated based on the presumed size of the warehouse. Screening meteorological data was used in this analysis, with wind directions at 45 degree intervals. Scaling factors were applied to the model's 1-hour results, as described in Section 5.2.8. The final results of this analysis are given in Table 5-25.

Table 5-23: Operating Scenario #8 Warehouse Predicted Results

Air Pollutant	Averaging Period	Peak Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
PM_{10}	24-Hour	10.8	30	55.1	65.9	150	44%
PM_{10}	Annual	0.9	17	7.5	8.4	NA [c]	NA [c]
$PM_{2.5}$	24-Hour	10.8	NA [b]	10	20.8	35	59%
$PM_{2.5}$	Annual	0.9	NA [b]	2	2.9	15	19%
NO_2	Annual	4.1	25	11.3	15.4	100	15%
SO_2	3-Hour	69.4	512	41.6	111.0	1300	9%
	24-Hour	41.6	91	13	54.6	365	15%
	Annual	3.5	20	2.6	6.1	80	8%
CO	1-Hour	27.2	NA [b]	1749	1776.2	40,000	4%
	8-Hour	24.4	NA [b]	1097	1121.4	10,000	11%

Reference: Shell Beaufort Permit Application 01/18/10

a. The sum of the predicted impact and existing background.
b. There are currently no PSD increments for $PM_{2.5}$ or CO.
c. The annual PM_{10} NAAQS, formerly set at 50 $\mu g/m^3$, has been revoked. The warehouse peak impact would be 17% of the former PM_{10} NAAQS.

Scenario #9 Tanker Modeling

A tanker is expected to accompany the drilling fleet at the distance of at least 25 miles from the Discoverer. It will not be approached the Discoverer. The tanker will be either the *Affinity* of a similar vessel. The 228-meter *Affinity* uses Distillate Marine C oil, similar to No. 4 oil. To model this vessel's emissions, Shell used a set of model receptors extending 5 kilometers in each direction, with 100 meter spacing between receptors. The results of this analysis are given in Table 5-24.

Table 5-24: Operating Scenario #9 Tanker Predicted Results

Air Pollutant	Averaging Period	Peak Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Back-ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
PM_{10}	24-Hour	6.9	30	55.1	62.0	150	41%
PM_{10}	Annual	0.5	17	7.5	8.0	NA [c]	NA [c]
$PM_{2.5}$	24-Hour	6.9	NA [b]	10	16.9	35	48%
$PM_{2.5}$	Annual	0.5	NA [b]	2	2.5	15	17%
NO_2	Annual	1.5	25	11.3	12.8	100	13%
SO_2	3-Hour	0.4	512	41.6	42.0	1300	3%

Air Pollutant	Averaging Period	Peak Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Back-ground ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
	24-Hour	0.2	91	13	13.2	365	4%
	Annual	0.02	20	2.6	2.6	80	3%
CO	1-Hour	8.3	NA [b]	1749	1757.3	40,000	4%
	8-Hour	7.4	NA [b]	1097	1104.4	10,000	11%

Reference: Shell Beaufort Permit Application 01/18/10

a. The sum of the predicted impact and existing background.

b. There are currently no PSD increments for $PM_{2.5}$ or CO.

c. The annual PM_{10} NAAQS, formerly set at 50 $\mu g/m^3$, has been revoked. The tanker peak impact would be 16% of the former PM_{10} NAAQS.

Modeled Results at Local Communities

Tables 5-25, 5-26, and 5-27 show the maximum predicted total impacts at the local communities of Kaktovik, Badami, and Nuiqsut, respectively. Because Kaktovik is over 200 km from the onshore sources, well beyond the extent of the onshore source modeling, the impacts of the onshore sources were not included in the Kaktovik totals. The Kaktovik total concentrations include the contribution from Shell sources at 13,000 meters, the nearest distance between Kaktovik and Shell's Beaufort Sea lease blocks, plus a background concentration. The impacts from the onshore sources at Badami are included in Table 5-26, along with Shell's contribution at 35,500 meters, the nearest distance between Badami and Shell's Beaufort Sea lease blocks, plus a background concentration. Nuiqsut is located well beyond the extent of Shell's 50-kilometer modeling range from the nearest lease block. No concentrations were modeled within Nuiqsut. Table 5-27 gives Shell's predicted concentrations at 50,000 meters from the primary ice breaker's usual location (about 45,000 meters from the Discoverer) as a conservative estimate of the project's potential impact at Nuiqsut and other locations further than 50 kilometers from Shell's drilling sites. Beyond 50 kilometers, the predictions of ISC3-PRIME are generally not used. Air concentrations tend to decrease as the distance from the emission source increases, so the true impact at Nuiqsut from Shell's proposed drilling activities is expected to be less than the values in Table 5-27. Overall, Shell's modeling results show that the emissions associated with the proposed permit are not expected to cause or contribute to a violation of the applicable NAAQS in the local communities.

Table 5-25: Impacts at Local Communities: Kaktovik

Air Pollutant	Averaging Period	Shell Contribution ($\mu g/m^3$) [a]	Onshore Source Contribution ($\mu g/m^3$) [b]	Back-Ground ($\mu g/m^3$)	Total [c] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10}	24-Hour	9.1	NA	55.1	64.2	150	43%
PM_{10}	Annual	0.4	NA	7.5	7.9	NA [d]	(16%) [d]
$PM_{2.5}$	24-Hour	8.3	NA	10	18.3	35	52%

Air Pollutant	Averaging Period	Shell Contribution ($\mu g/m^3$) [a]	Onshore Source Contribution ($\mu g/m^3$) [b]	Back-Ground ($\mu g/m^3$)	Total [c] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
$PM_{2.5}$	Annual	0.4	NA	2.0	2.4	15	16%
NO_2	Annual	8.2	NA	11.3	19.5	100	20%
CO	1-Hour	186.4	NA	1749	1935.4	40000	5%
	8-Hour	134.7	NA	1097	1231.7	10000	12%
SO_2 [b]	3-Hour	1.4	NA	41.6	43.0	1300	3%
	24-Hour	0.3	NA	13	13.3	365	4%
	Annual	0.01	NA	2.6	2.61	80	3%

Reference: Environ 02/05/10
a. Shell's contribution at 13,000 m from drill hole, which is the shortest distance between Kaktovik and the Shell Beaufort Sea lease blocks.
b. The contribution of onshore sources to Kaktovik was not calculated due to their distance from the village, over 200 km.
c. The sum of Shell's contribution, onshore source contribution, and background.
d. The annual PM_{10} NAAQS, formerly set at 50 $\mu g/m^3$, has been revoked.

Table 5-26: Impacts at Local Communities: Badami

Air Pollutant	Averaging Period	Shell Contribution ($\mu g/m^3$) [a]	Onshore Source Contribution ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total [b] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10}	24-Hour	5.4	.99	55.1	61.5	150	41%
PM_{10}	Annual	0.2	.05	7.5	7.8	NA [c]	(16%) [c]
$PM_{2.5}$	24-Hour	4.9	.99	10	15.9	35	45%
$PM_{2.5}$	Annual	0.2	.05	2.0	2.3	15	15%
NO_2	Annual	4.6	1.24	11.3	17.1	100	17%
CO	1-Hour	91.1	NA [d]	1749	1840.1	40000	5%
	8-Hour	73.3	NA [d]	1097	1170.3	10000	12%
SO_2	3-Hour	0.6	24.4	41.6	66.6	1300	5%
	24-Hour	0.2	5.64	13	18.8	365	5%
	Annual	0.01	0.28	2.6	2.9	80	4%

Reference: Environ 02/05/10
a. Shell's contribution at 35,500 m from drill hole, which is the shortest distance between Badami and the Shell Beaufort Sea lease blocks.
b. The sum of Shell's contribution, onshore source contribution, and background.

c. The annual PM_{10} NAAQS, formerly set at 50 μg/m^3, has been revoked.
d. CO was not included in full PSD/NAAQS analysis; therefore onshore sources' CO emissions were not modeled.

Table 5-27: Impacts at Local Communities: Nuiqsut

Air Pollutant	Averaging Period	Shell Contribution (μg/m^3) [a]	Back-Ground (μg/m^3)	Total [b] (μg/m^3)	NAAQS (μg/m^3)	Percent of NAAQS
PM_{10}	24-Hour	4.8	55.1	59.9	150	40%
PM_{10}	Annual	0.2	7.5	7.7	NA [c]	(15%) [c]
$PM_{2.5}$	24-Hour	4.4	10	14.4	35	41%
$PM_{2.5}$	Annual	0.2	2.0	2.2	15	15%
NO_2	Annual	3.9	11.3	15.2	100	15%
CO	1-Hour	78.7	1749	1827.7	40000	5%
	8-Hour	64.3	1097	1161.3	10000	12%
SO_2	3-Hour	0.5	41.6	42.1	1300	3%
	24-Hour	0.2	13	13.2	365	4%
	Annual	0.01	2.6	2.6	80	3%

Reference: Environ 02/08/10
a Shell's contribution at 50,000 meters from primary ice breaker; 45,000 meters from the drill hole.
b The sum of Shell's contribution and background.
c The annual PM_{10} NAAQS, formerly set at 50 μg/m^3, has been revoked.

5.2.24 Ozone

Because NO_X and VOC net emissions exceed 100 tpy, Shell is required under the PSD regulation to perform an ozone ambient air quality impact analysis including gathering ambient air measurements. Ozone is inherently a regional pollutant, the result of chemical reactions between emissions from many sources over a period of hours or days, and over a large area. Ozone is formed in the 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.

EPA does not have a recommended modeling approach for assessing the impact of an individual source on ozone. Individual source impacts are generally within the range of "noise" of regional ozone models (i.e., imprecision in predicted concentration due to uncertainty in model inputs for emissions, chemistry, and meteorology). EPA's Guideline on Air Quality Models (40 C.F.R. 51, App. W), which is applicable to PSD permit modeling, reflects this understanding. Guideline § 5.2.1(a) notes that "Simulation of ozone formation and transport is a highly complex and resource intensive exercise," and paragraph (c) states: "Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the Regional Office to determine the most suitable approach on a case-by-case basis." Under the Guideline, EPA has considerable discretion in methods for assessing the ozone impact of individual sources. See In re: Prairie State Generating Company, 13 E.A.D. __, PSD Appeal No. 05-05, slip op. at 133 (EAB 2006). In practice, it is very rare for EPA to require ozone modeling for individual sources.

The land area closest to Shell's exploration operations in the Beaufort Sea is part of the State of Alaska's Northern Alaska Intrastate AQCR. See 40 C.F.R. § 81.246. This region is designated as either attainment or unclassifiable for all criteria pollutants, including ozone. See 40 C.F.R. § 81.301. Ozone precursor emissions from point and area sources in the North Slope Borough are approximately 42,500tpy of NO_X and 1,600 tpy of VOC (Shell Beaufort Permit Application 01/18/10, Section 8.4).[19] Point sources in the North Slope oil and gas fields near Deadhorse contribute approximately 41,000 tpy of NO_X and 1,100 tpy of VOC. In contrast, potential emissions from Shell's exploration operations are expected to be approximately 1371 tpy of NO_X and 96 tpy of VOC (Shell Beaufort Permit Application 01/18/10, Table 3-1).

Over the past ten years, there have been monitoring programs that measured ozone and ozone precursors (i.e., NO_X and VOC) in the North Slope where oil and gas operations are currently located. The ozone measurement programs include Barrow (2003 - 2005), BPX-Badami (1999), BPX-Prudhoe Bay (2006 - 2007), CPAI-Alpine (Nov 2004 - Dec 2005) and CPAI-Kuparuk River (Jun 2001 - June 2002). Measurements from these six sites indicate that the highest 1-hour concentration was 73 parts per billion (ppb)while the highest 8-hour measurement was 50 ppb. The hourly concentration represents 61 percent of the 120 ppb hourly NAAQS. The 8-hour concentration represents 67 percent of the 75 ppb of the 2008 8-hour NAAQS (Shell Beaufort Permit Application 01/18/10, Table 8-3).

Given the low level of ozone precursor emissions from Shell's exploration operations in comparison to regional emissions of ozone precursors and the moderate levels of 1-hour and 8-hour ozone measured on the North Slope, the contribution of the ozone precursor emissions from Shell's exploration operations to the formation of ozone in the region is expected to be small. For these reasons, EPA believes that emissions from Shell's exploration operations will not cause or contribute to a violation of the NAAQS for ozone.

[19] Data from 2002, Western Regional Air Partnership (WRAP) Emissions Data Management System (EDMS).

5.3 Class I Areas and Additional Impacts Analysis

5.3.1 Class I Area

The nearest Class I area is Denali National Park, located about 750 kilometers from the Shell lease blocks in the Beaufort Sea. Based on the distance and the amount of emissions, the National Park Service did not request Class I area quality increment analysis for Denali National Park (Notar 08/05/09).

5.3.2 Additional Impacts Analyses

As discussed in Section 5.1 above, 40 C.F.R. § 52.21(o) requires additional impact analyses, which must include an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the proposed source modification, or that would occur as a result of any commercial, residential, industrial and other growth associated with the source modification. 40 C.F.R. § 52.21(p) has additional requirements for mandatory federal Class I areas.

5.3.3 Class II Area Visibility

The National Park Service identified two Class II national monuments as areas of concern (Notar 06/03/09): Cape Krusenstern National Monument and Bering Land Bridge National Monument. Since the Shell Beaufort Sea lease blocks are about 675 kilometers from these national monuments, the National Park Service believes that the Shell project should not adversely affect visibility at the monuments (Notar 08/05/09).

5.3.4 Local Visibility

Fog is a natural occurring atmospheric event over land and over water. It usually forms when moist air cools to below its dew point. Freezing fog occurs when liquid fog droplets freeze to tiny particles in the air. Ice fog occurs when droplets have frozen into tiny crystals of ice in air which generally requires temperatures below 30 ^{o}F (Shell Beaufort Permit Application 01/18/10). EPA estimates the water vapor emissions to be 67 tons per day from the Discoverer and 395 tons per day from all combustion sources. Water vapor emissions from the Discoverer and the Associated Fleet may contribute to fog formation depending on atmospheric conditions.

Visible exhaust plumes are expected from the Discoverer and Associated Fleets activities during exploratory drilling activities. The proposed permit limits also visible emissions. Therefore, in light of the permit conditions and because of the location of Shell's operations in the Beaufort Sea, visibility impairment from the exhaust plumes is not expected to be of concern.

5.3.5 Soils and Vegetation

Shell is required to provide an analysis of the impairment to soils and vegetation in the significant impact area of the proposed new source that is expected to occur as a result of its permitted activities and general commercial, residential, industrial, and other growth associated with the project. Analysis for vegetation having no significant commercial or recreational value is not required. Most of the area within the largest possible significant impact area radius of 50-kilometers centered on the Discoverer is ocean. Shell analyzed the potential impacts from the project on aquatic vegetation having commercial or recreational value and sediment by reviewing published literature and consulting with numerous government agencies, local groups and residents, and the University of Alaska (Shell Beaufort Permit Application 01/18/10). Shell did not identify any negative impacts on aquatic vegetation having significant commercial or recreational value nor on sediment in the significant impact areas expected to be impacted by air emissions from Shell's exploration drilling operations in the Beaufort Sea. Additionally Shell considered potential impacts to onshore vegetation and soils. Portions of the Arctic Coastal Plain lie within 50 kilometers of the Shell lease blocks. This area is characterized by thick permafrost and tundra. Shell consulted with local residents, federal and state agencies, the Alaska Center for the Environment and the University of Alaska Fairbanks. No soil and vegetation resources with significant recreation or commercial value were identified. (See Shell Beaufort Permit Application 01/18/10, Section 8.2.) Thus, additional analysis is not required.

5.3.6 Growth

Temporary growth and support facilities are expected at several possible coastal locations to support Shell's drilling activities offshore of northern Alaska. The location of the growth and facilities could occur at Wainwright, Barrow, Kotzebue, and Deadhorse. (Growth in Wainwright, Barrow, or Kotzebue is not addressed in this permitting action.) Because Shell's drilling projects are seasonal, no significant permanent local growth is expected to be associated with the project. Rotating work crews could lodge at local hotels and trailer camps. Helicopters will be used to transport work crews to and from the Discoverer. These activities are not expected to significantly increase local air emissions. (See Section 5.2.5 for a discussion of helicopter emissions.) In addition, Shell contemplates building a warehouse, heated by either natural gas or heating oil, at either Wainwright, Barrow, or Deadhorse. As shown in Table 5-23, the emissions associated with heating a warehouse in the Deadhorse area are not expected to contribute to a violation of the NAAQS or noncompliance with PSD increments.

5.3.7 Air Quality Related Values Including Visibility

Under 40 C.F.R. § 52.21(p), the Federal Land Managers are responsible for the management of mandatory federal Class I areas, including the protection of air quality related values. The air quality related values include sulfate and nitrate deposition and visibility impairment. The nearest Class I area is the Denali National Park, located approximately 750 kilometers south of Shell's proposed drilling locations in the Beaufort Sea. At this distance, the National Park Service does not expect significant sulfate and nitrate deposition, or visibility impairment impacts at this mandatory federal Class I area (Notar 08/05/09).

6 OTHER REQUIREMENTS

6.1 Endangered Species Act and Essential Fish Habitat of Magnuson-Stevens Act

Section 7(a)(2) of the Endangered Species Act (ESA) requires federal agencies, in consultation with the National Oceanic and Atmospheric Administration (NOAA) Fisheries and/or the U.S. Fish and Wildlife Service (collectively, "the Services"), to ensure that any action authorized, funded, or carried out by the agency is not likely to jeopardize the continued existence of a species listed as threatened or endangered, or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. §1536(a)(2); see also 50 C.F.R §§ 402.13, 402.14. The federal agency is also required to confer with the Services on any action which is likely to jeopardize the continued existence of a species proposed for listing as threatened or endangered or which will result in the destruction or adverse modification of critical habitat proposed to be designated for such species. 16 U.S.C. §1536(a)(4); see also 50 C.F.R § 402.10. Further, the ESA regulations provide that where more than one federal agency is involved in an action, the consultation requirements may be fulfilled by a designated lead agency on behalf of itself and the other involved agencies. 50 C.F.R § 402.07.

The Minerals Management Service (MMS) is the lead agency for ESA Section 7 compliance for Shell's oil exploration activities and has consulted with the Services regarding Shell's activities in the Beaufort Sea. In conclusion of those consultations, U.S. FWS issued its Biological Opinion for Beaufort and Chukchi Sea Program Area Lease Sales and Associated Seismic Surveys and Exploratory Drilling on September 3, 2009 and NOAA's National Marine Fisheries Service issued its revised Biological Opinion for Federal oil and gas leasing and exploration by the Minerals Management Service within the Alaskan Beaufort and Chukchi Seas on July 17, 2008.

In fulfilling our ESA obligations for this permitting action, we intend to rely on these consultations while also conducting additional compliance activities, if any, necessary to address any EPA-permitted activities not covered in those consultations. EPA has begun discussions with the Services regarding our permitting action and potential impacts on protected species. Any final air permit that we may issue in this action will, as appropriate, include additional conditions that may be identified during the ESA process.

6.1.1 Essential Fish Habitat of Magnuson-Stevens Act

Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires federal agencies to consult with NOAA National Marine Fisheries Service (NMFS) with respect to any action authorized, funded, or undertaken by the agency that may adversely affect any essential fish habitat (EFH) identified under the MSA.

MMS is the lead federal agency for authorizing oil and gas exploration activities on the Alaska outer continental shelf, including the Beaufort Sea. In accordance with the MSA, MMS consults on essential fish habitat at the oil and gas lease sale stage and consulted with NMFS in connection with its Arctic Multiple-Sale Draft Environmental Impact Statement. The MMS and NMFS also consulted regarding the associated affects of oil and gas exploration activities on EFH in the Beaufort Sea area and on June 26, 2009, NMFS documented the consultation and included EFH Conservation Recommendations pursuant to Section 305(b)(4)(A) of the MSA.

In fulfilling our MSA obligations for this permitting action, we intend to rely on the consultations between MMS and the Service while also conducting additional compliance activities, if any, necessary to address any EPA-permitted activities that may adversely affect any EFH identified under the MSA. Any final air permit that EPA may issue in this action will, as appropriate, include additional conditions that may be identified during the MSA process.

Exhibit 5
AEWC & ICAS

6.2 National Historic Preservation Act

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to take into account the effects of their undertakings on historic properties. Section 106 requires the lead agency official to ensure that any federally funded, permitted, or licensed undertaking will have no effect on historic properties that are on or may be eligible for the National Register of Historic Places. The Section 106 process seeks to accommodate historic preservation concerns with the needs of federal undertakings through consultation among the agency official and other parties with an interest in the effects of the undertaking on historic properties, commencing at the early stages of project planning. The goal of consultation is to identify historic properties potentially affected by the undertaking, assess the potential effects of the undertaking on historic properties, and seek ways to avoid, minimize, or mitigate any adverse effects on historic properties. If more than one federal agency is involved in an undertaking, some or all the agencies may designate a lead federal agency for this analysis. Section 106 requires the lead agency to consult with the State Historic Preservation Office (SHPO) on actions that may affect historical sites. As the lead action agency, MMS has consulted and will continue to consult with the SHPO on Shell's oil exploration activities in federal waters. In a letter dated November 13, 2009, MMS sought the SHPO's concurrence in MMS's determination that Shell's exploratory drilling in Lease Area 195 (March 2005) and 202 (April 2007) under Shell's Exploration Plan will have no effect on historic properties. The SHPO concurred in MMS's determination on November 17, 2009. In fulfilling its NHPA obligations for this permitting action, EPA intends to rely on these MMS consultations. EPA will conduct additional compliance activities necessary to address any EPA-permitted activities not covered in MMS' consultations.

6.3 Coastal Zone Management

The Alaska Coastal Management Program (ACMP), authorized by the State of Alaska's 1977 Alaska Coastal Management Act, is designed to protect Alaska's rich and diverse coastal resources to ensure a healthy and vibrant coast that sustains long-term economic and environmental productivity. The ACMP requires that certain projects that will be conducted in Alaska's coastal zone be reviewed by coastal resource management professionals and found consistent with the statewide standards of the ACMP.

Pursuant to Title 11 of the Alaska Administrative Code at 11AAC 110.400 (b)(5), projects requiring the following EPA permits must undergo an ACMP consistency review:

A. permit required under 33 U.S.C. 1342 (Clean Water Act), authorizing discharge of pollutants into navigable waters;

B. permit required under 33 U.S.C. 1345 (Clean Water Act), authorizing disposal of sewage sludge;

C. permit under 40 C.F.R. Part 63 for new sources or for modification of existing sources, or a waiver of compliance allowing extensions of time to meet air quality standards under 42 U.S.C. 7412 (CAA); or

D. air quality exemption granted under 40 C.F.R. 60.14 or 40 C.F.R. 64.2 for stationary sources;

The OCS/PSD permit at issue in this action does not appear on the list. Thus, issuance of this OCS/PSD permit is not required to be preceded by an ACMP consistency review.

6.4 Executive Order 12898 – Environmental Justice

Executive Order (EO) 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," 59 FR 7629 (February 11, 1994) (EO 12898), directs federal agencies, including EPA, to the extent practicable and permitted by law, to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of regulatory programs, policies, and activities on minority populations or low-income populations. EO 12898 at § 1-101.

Consistent with EO 12898 and EPA's environmental justice policy (OEJ 07/24/09), in making decisions regarding permits, such as OCS and PSD permits, EPA gives appropriate consideration to environmental justice issues on a case-by-case basis, focusing on whether its action would have disproportionately high and adverse human health or environmental effects on minority or low-income populations. EPA's proposed OCS/PSD air permitting action on the Beaufort Sea potentially affects a number of communities on the North Slope, many of which participate in subsistence harvests of marine and terrestrial resources in the region. EPA's review of demographic characteristics showed that many of the potentially impacted communities have a significantly high percentage of Alaskan Natives, who are considered a minority under EO 12898, and people who speak a language other than English at home (EJ GAT 07/28/09).

EPA has taken several measures to provide meaningful involvement for the environmental justice communities potentially impacted by this permit. EPA has recently developed the "Region 10 North Slope Communications Protocol" to support the meaningful involvement of the North Slope communities in EPA decision-making (NSCP 05/09). The development of the public participation process for this permit was guided by the NSCP and will inform the communities of the North Slope about the OCS permitting program and this proposed OCS/PSD permit. In an effort to engage the potentially affected communities early in the process, managers of EPA Region 10's air and water programs conducted early outreach on air and water permitting in May 2009 in Kotzebue and Barrow (EPA 07/27/09 Outreach Memo). EPA has held meetings and conference calls to specifically solicit input on environmental justice concerns related to this permitting action, as well as other potential OCS air permitting actions on the Beaufort and Chukchi Seas (ICAS 07/23/09; NSB 06/26/09 Transcript). EPA has also scheduled public hearings on this proposed permit.

As described above, EPA has carefully considered and documented the environmental effects of its proposed permitting decision by analyzing potential air emissions associated with the exploration drilling activity to be conducted under the permit. As required by the applicable OCS and PSD regulations, the terms and conditions of the final permit must ensure that activities authorized by the permit will not cause a violation of the NAAQS. See 40 C.F.R. §§ 55.13(d), 52.21(a)(2)(iii) and 52.21(k). NAAQS are national health-based standards that have been set at a level such that their attainment and maintenance will protect public health and welfare, allowing for an adequate margin of safety. See Section 109(b) of the CAA. EPA specifically solicits comment on our proposed determination that the terms and conditions of the permit ensure attainment of the NAAQS.

6.5 Executive Order 13175 – Tribal Consultation

Pursuant to Executive Order 13175 issued on November 9, 2000 and entitled, "Consultation and Coordination with Indian Tribal Governments," federal agencies are required to have an accountable process to assure meaningful and timely input by Tribal officials in the development of regulatory policies on matters that have tribal implications. 65 FR 67249 (November 9, 2000). In accordance with Region 10's May 2009 North Slope Communications Protocol, a regional policy for early community and tribal involvement, EPA held an informal informational meeting in Barrow on May 29, 2009 to discuss the upcoming air permitting actions.

Prior to beginning the public comment period on the proposed permit, EPA sent letters to 11 potentially interested tribal governments, offering government-to-government consultation opportunities on EPA's proposed action to issue Shell OCS/PSD permits for exploration drilling on the Beaufort and Chukchi Seas. The letters were sent on June 26, 2009 to Native Village of Point Hope, Native Village of Point Lay, Wainwright Traditional Council, Native Village of Anuktuvuk Pass, Native Village of Atqasuk, Native Village of Barrow, Inupiat Community of the Arctic Slope, Native Village of Kaktovik, and Native Village of Nuiqsut, and specified that requests for consultation be made no later than July 15, 2009. Because July is a busy time of year for Alaska Native communities due to subsistence activities, EPA also attempted to contact each of these tribal governments to ensure the letters were received.

EPA received a request for tribal consultation from the Native Village of Nuiqsut. In addition, EPA received a request for tribal consultation from the Inupiat Community of the Arctic Slope (ICAS) and held a government-to-government consultation meeting with ICAS in Barrow on September 23, 2009. Concerns expressed included drilling during November and December due to severe winter conditions; a desire for more information regarding the air quality model; the reliability of self-monitoring data and a preference for monitoring data collected by an independent third party; and a request that monitoring information and data be reported to the communities.

ICAS also requested that EPA consult with all tribal governments on the North Slope and that this occur in person in the local communities. EPA held informational meetings for the local communities of Point Hope, Barrow, and Wainwright during the week of September 21, 2009. The informational meeting in Point Hope on September 24, 2009, did end up including an unscheduled government-to-government consultation meeting with the Native Village of Point Hope. Concerns expressed at the consultation with the Native Village of Point Hope included the adequacy of the baseline air quality data for the Beaufort and Chukchi Seas; a desire for community involvement in the collection of baseline data collection and compliance monitoring; and the potential impact on respiratory health. The Native Village of Point Hope requested another opportunity for government-to-government consultation with EPA to discuss their concerns prior to the finalization of the Shell OCS/PSD permit.

In addition to notifying these tribal governments of the opportunity for government-to-government consultation, EPA will also notify tribal entities of the opportunity to provide public comment on the proposed permit during the public comment period and to attend and provide testimony during the scheduled public hearing.

Exhibit 5
AEWC & ICAS

6.6 National Environmental Policy Act

The National Environmental Policy Act (NEPA) establishes a national environmental policy and goals for the protection, maintenance, and enhancement of the environment. NEPA includes a process for implementing these goals by federal agencies when they undertake major federal actions. The NEPA process involves an assessment of the environmental effects of a proposed action and alternatives. For projects that have the potential for significant environmental effects or that are environmentally controversial, a detailed statement called an Environmental Impact Statement is prepared.

Section 7(c) of the Energy Supply and Environmental Coordination Act of 1974 specifically exempts actions under the CAA, including issuance PSD permits, from the requirements of NEPA. EPA is therefore not required to develop an EIS prior to issuance of this permit.

ABBREVIATED REFERENCES

Air Sciences 04/20/09. E-mail from Rodger Steen, Air Sciences, Inc., to Paul Boys, EPA, dated April 20, 2009, re: SCR System for Discoverer.

Alaska Department of Environmental Conservation Standard Permit Condition I – Emission Fees, revised August 25, 2004.

Alaska Department of Environmental Conservation Standard Permit Condition II – Air Pollution Prohibited, revised August 25, 2004.

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APPENDIX A: CRITERIA POLLUTANT PTE EMISSION INVENTORY

APPENDIX A

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Potential to Emit Emission Inventory

Summary of Annual Emissions

Frontier Discoverer Sources

			Potential to Emit (tons/year)						
Unit ID	**Description**	**Make/Model**	**CO**	**NO_x**	**$PM_{2.5}$**	**PM_{10}**	**SO_2**	**VOC**	**Lead**
FD-1	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-2	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-3	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-4	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-5	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-6	Generator Engine	Caterpillar D399	0.56	1.55	0.40	0.40	2.00E-02	0.08	4.04E-04
FD-7[1]	Propulsion Engine	MI / 6UEC65	0.00	0.00	0.00	0.00	0.00E+00	0.00	0.00
FD-8	Emergency Generator	Caterpillar 3304	4.30E-02	7.82E-02	1.54E-02	1.54E-02	3.51E-05	8.16E-03	6.38E-07
FD-9-11[2]	MLC Compressor	Caterpillar C-15	2.50	5.37	0.13	0.13	8.63E-03	5.37	1.57E-04
FD-12-13[3, 4]	HPU Engine	Detroit/8V71	0.25	8.18	0.16	0.16	4.71E-03	0.12	8.56E-05
FD-14-15[5]	Deck Cranes	Caterpillar D343	0.20	9.50	0.07	0.07	6.76E-03	0.06	1.23E-04
FD-16-20[6]	Cementing Units and Logging Winches	Various	0.66	11.84	0.29	0.29	5.71E-03	3.01	1.04E-04
FD-21	Heat Boiler	Clayton 200 Boiler	1.25	3.23	0.38	0.38	2.56E-02	0.02	1.45E-04
FD-22	Heat Boiler	Clayton 200 Boiler	1.25	3.23	0.38	0.38	2.56E-02	0.02	1.45E-04
FD-23	Incinerator	TeamTec GS500C	0.39	0.06	0.09	0.10	3.15E-02	0.04	2.68E-03
FD-24-30[7]	Fuel Tanks	NA						0.01	
FD-31	Supply Ship at Discoverer	NA	0.09	0.43	0.03	0.03	1.56E-04	0.03	2.85E-06
FD-32[8]	Drilling Mud System	NA						0.06	
FD-33[9]	Shallow Gas Diverter System	NA						0.00	
FD-34[10]	Cuttngs/Muds Disposal Barge	NA							
	Sub-Total Emissions from Frontier Discoverer		10.00	51.23	3.95	3.96	0.23	9.23	0.01

Associated Fleets

	Potential to Emit (tons/year)						
Description	**CO**	**NO_x**	**$PM_{2.5}$**	**PM_{10}**	**SO_2**	**VOC**	**Lead**
Ice Management Fleet - Generic							
Ice Breaker # 1	160.50	849.88	33.60	38.43	0.65	35.87	3.74E-02
Ice Breaker #2	237.17	71.19	11.15	11.79	0.68	27.69	3.73E-02
Resupply Ship - Generic	0.56	4.24	0.26	0.32	1.13E-03	0.10	2.06E-05
OSR Fleet - Generic							
Nanuq - Main Ship	39.14	172.35	1.86	2.51	0.39	13.59	2.81E-02
Point Barrow Tug and Arctic Endeavor - Main Ships	14.56	166.88	5.55	6.63	0.06	8.60	1.13E-03
Oil Spill Response, Kvichak No. 1, 2 and 3 Work Boats	2.23	55.72	1.03	1.03	0.06	1.06	1.08E-03
Sub-Total Emissions from Fleets	454.15	1,320.25	53.44	60.70	1.84	86.90	0.10
TOTAL PROJECT EMISSIONS	464.15	1371.48	57.39	64.66	2.07	96.14	0.11

Notes

1 Propulsion engine is not used when Discoverer is an OCS Source.
2 Combined use of all 3 MLC Compressor engines are limited by an aggregate fuel usage limit.
3 Combined use of both HPU are limited by an aggregate fuel usage limit.
4 PTE of HPU Units and Incinerator are based on maximum use of that emission unit in accordance with alternative operating scenarios.
5 Combined use of both deck cranes are limited by an aggregate fuel usage limit.
6 Combined use of all five cementing unit and logging winch engines are limited by an aggregate fuel usage limit.
7 Tanks calculations and software outputs are listed separately but are summarized in this table.
8 Drilling mud system calculations are listed separately but are summarized in this table.
9 Shallow gas diverter system is not expected to be used as part of planned operations.
10 Cuttings/Muds Disposal barge is prohibited from emitting any air pollutants.

Exhibit 5
AEWC & ICAS

	Potential to Emit (lb/hr)						
	CO	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC	Lead
FD-1	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-2	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-3	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-4	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-5	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-6	0.28	0.77	0.20	0.20	1.10E-02	0.04	2.00E-04
FD-7	0.00	0.00	0.00	0.00	0.00E+00	0.00	0.00
FD-8	1.79	3.26	0.64	0.64	1.46E-03	3.40E-01	2.66E-05
FD-9	1.65	3.55	0.10	0.10	5.71E-03	3.55	1.04E-04
FD-10	1.65	3.55	0.10	0.10	5.71E-03	3.55	1.04E-04
FD-11	1.65	3.55	0.10	0.10	5.71E-03	3.55	1.04E-04
FD-12	0.16	5.41	0.10	0.10	3.11E-03	0.08	5.66E-05
FD-13	0.16	5.41	0.10	0.10	3.11E-03	0.08	5.66E-05
FD-14	0.13	6.20	0.04	0.04	4.41E-03	0.04	8.01E-05
FD-15	0.13	6.20	0.04	0.04	4.41E-03	0.04	8.01E-05
FD-16	0.22	7.25	0.14	0.14	4.17E-03	0.11	7.58E-05
FD-17	0.22	7.25	0.14	0.14	4.17E-03	0.11	7.58E-05
FD-18	0.21	3.80	0.09	0.09	1.83E-03	0.07	3.33E-05
FD-19	0.29	1.64	0.01	0.01	2.79E-03	1.64	5.08E-05
FD-20	0.03	0.43	0.01	0.01	3.91E-04	0.04	7.11E-06
FD-21	0.62	1.60	0.19	0.19	1.27E-02	0.01	7.17E-05
FD-22	0.62	1.60	0.19	0.19	1.27E-02	0.01	7.17E-05
FD-23	4.28	0.69	0.97	1.13	3.45E-01	0.41	2.94E-02
FD-31	1.94	9.01	0.63	0.63	3.26E-03	0.00	5.93E-05
	17.43	75.02	4.79	4.96	0.49	13.87	0.03

	Potential to Emit (lb/hr)						
	CO	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC	Lead
IB	163.84	1051.42	40.25	45.75	4.93E-01	32.90	2.17E-02
AH	234.48	92.22	11.37	11.69	5.08E-01	23.81	2.14E-02
RS-T	34.89	264.92	16.06	20.02	7.09E-02	6.26	1.29E-03
OSR-MS	28.26	352.96	4.60	5.64	2.88E-01	11.95	1.57E-02
OSR-WB	1.11	27.64	0.51	0.51	2.94E-02	0.53	5.34E-04
	462.57	1,789.16	72.80	83.62	1.39	75.44	0.06
	480.00	1864.18	77.59	88.57	1.88	89.31	0.09

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	FD-1-6	Generator Engine
Make/Model[1]:	Caterpillar D399, SCAC, 1200 rpm	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	1,325	hp
Maximum Operating Level[5]:	941	hp
Maximum Hourly Fuel Use[3,5]:	367	lbs/hour
Control Equipment:	SCR for NO_X, catalytic oxidation for CO, VOC, PM_{10} and $PM_{2.5}$	

Emissions are on a per-engine basis

Pollutant	Emission Factors[4]	Emission Factor Units	Maximum Hours of Operation		Control Efficiency[6]	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	882.7	g/hr	24	4032	0.8	0.28	6.72	0.56	0.035	0.035	0.016
NO_x	0.5	g/kW-h	24	4032		0.77	18.48	1.55	0.097	0.097	0.045
$PM_{2.5}$	251.2	g/hr	24	4032	0.5	0.20	4.8	0.40	0.025	0.025	0.012
PM_{10}	251.2	g/hr	24	4032	0.5	0.20	4.8	0.40	0.025	0.025	0.012
SO_2	0.000030	lb/lb fuel	24	4032		1.10E-02	0.26	2.00E-02	1.39E-03	1.36E-03	5.75E-04
VOC	75.5	g/hr	24	4032	0.7	0.04	0.96	0.08	5.04E-03	5.04E-03	2.30E-03
Lead	0.000029	lb/MMBtu	24	4032		2.00E-04	4.81E-03	4.04E-04	2.52E-05	2.52E-05	1.16E-05

Emissions Factor References

CO	From Caterpillar, See permit application dated 01-18-10, Appendix A, page 1
NO_x	From 10-9-2008 D.E.C. Marine letter to Shell. See permit application dated 01-18-10, Appendix C
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Caterpillar, See permit application dated 01-18-10, Appendix A, page 1
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	VOC emissions data from Caterpillar, See permit application dated February 23, 2009, Appendix B, page 28
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per 4/6/2009 and 4/9/2009 e-mails from Air Sciences (Rodger Steen) to EPA (Pat Nair)
2 Engine rating per permit application dated 01-18-10, Appendix A, page 1
3 Fuel usage from Caterpillar, See permit application dated 01-18-10, Appendix A, page 1
237.5 g/kW-hr converted based on engine rating, and watts/hp and g/lb conversions
4 All emission factors are uncontrolled except for NOx, which reflects guaranteed emission rate.
5 Owner requested limit per permit application dated 01-18-10, Appendix A, page 1 71% load
6 Control efficiency is based on use of oxidation catalyst. NOx emission factor already reflects controlled emission rate.

Exhibit 5
AEWC & ICAS

127.005 g/hr	0.135 g/hp-hr	0.18104 g/kW-hr
90.718 g/hr	0.09643 g/hp-hr	0.12932 g/kW-hr
90.718 g/hr	0.09643 g/hp-hr	0.12932 g/kW-hr
18.1436 g/hr	0.01929 g/hp-hr	0.02586 g/kW-hr

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-8	Emergency Generator Engine
Make/Model[1]:	Caterpillar 3304	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	131	hp
Maximum Hourly Fuel Use[3]:	49	lbs/hour
Control Equipment:	None	

Emissions are on a per-engine basis.

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[4]		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	6.2	g/hp-hr	2.00	48		1.79	3.58	4.30E-02	0.226	0.019	1.24E-03
NO_x	11.28	g/hp-hr	2.00	48		3.26	6.52	7.82E-02	0.411	0.034	2.25E-03
$PM_{2.5}$	2.21	g/hp-hr	2.00	48		0.64	1.28	1.54E-02	0.081	0.007	4.42E-04
PM_{10}	2.21	g/hp-hr	2.00	48		0.64	1.28	1.54E-02	0.081	0.007	4.42E-04
SO_2	0.000030	lb/lb fuel	2.00	48		1.46E-03	2.93E-03	3.51E-05	1.84E-04	1.54E-05	1.01E-06
VOC	1.163	g/hp-hr	2.00	48		0.34	0.68	8.16E-03	4.28E-02	3.57E-03	2.35E-04
Lead	0.000029	lb/MMBtu	2.00	48		2.66E-05	5.32E-05	6.38E-07	3.35E-06	2.79E-07	1.84E-08

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 2
2 Engine rating per permit application dated 01-18-10, Appendix A, page 2
3 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on engine rating, fuel density and fuel heat content
4 Operation is restricted to 120 minutes of operation per day and 48 hours per year per permit application dated 01-18-10, Appendix A, page 2

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-9-11	MLC Compressor
Make/Model[1]:	Caterpillar C-15	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	540	hp
Maximum Hourly Fuel Use[3]:	190	lbs/hour
Control Equipment:	Tier 3 engines	

Hourly and daily emissions are on a per-engine basis. Annual emissions are for all three MLC compressor engines in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[4, 5]		Control Efficiency[6]	Potential to Emit			Potential to Emit in g/sec		
			Daily (hrs)	Annual (gal)		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	1.86	g/kW-h	24	81,346		1.65	39.6	2.50	0.208	0.208	0.072
NO_x	4.0	g/kW-h	24	81,346		3.55	85.2	5.37	0.447	0.447	0.154
$PM_{2.5}$	0.2	g/kW-h	24	81,346	0.5	0.1	2.4	0.13	0.013	0.013	0.004
PM_{10}	0.2	g/kW-h	24	81,346	0.5	0.1	2.4	0.13	0.013	0.013	0.004
SO_2	0.000030	lb/lb fuel	24	81,346		5.71E-03	0.14	8.63E-03	7.19E-04	7.35E-04	2.48E-04
VOC	4.0	g/kW-h	24	81,346		3.55	85.2	5.37	4.47E-01	4.47E-01	1.54E-01
Lead	0.000029	lb/MMBtu	24	81,346		1.04E-04	2.49E-03	1.57E-04	1.31E-05	1.31E-05	4.52E-06

Emissions Factor References

CO	Controlled emission factor from EPA BACT analysis (OxyCat as BACT).
NO_x	From Tier 3 emission limit in 40 CFR 89.112 (Limit is for NO_X and NMHC, in aggregate)
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	Assumed to be the same as PM from Tier 3 emission limit in 40 CFR 89.112 and use of OxyCAT
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Tier 3 emission limit in 40 CFR 89.112 (Limit is for NO_X and NMHC, in aggregate)
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59	g/lb
2,000	lbs/ton
745.7	watts/hp
7.076	lbs/gal
133,098	Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 3
2 Engine rating per permit application dated 01-18-10, Appendix A, page 3
3 Fuel usage from Caterpillar LEHW7443-00, 2008
26.9 gal/hr and then converted based on fuel density
4 Daily maximum operation is based on hours of operation
5 Annual maximum operation is based on fuel usage for all three engines: 81,346 gallons
6 Control efficiency is based on use of oxidation catalyst. CO emission factor already reflects controlled emission rate.

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-12-13	HPU Engine
Make/Model[1]:	Detroit 8V-71	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	250	hp
Maximum Hourly Fuel Use[3]:	104	lbs/hour
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC	

Hourly emissions are on a per-engine basis. Daily and annual emissions are for both HPU engines in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[6, 7] Daily (gal)	Annual[8] (gal)	Control Efficiency[4, 5]	Potential to Emit Hourly, lb/hr	Daily[7], lb/day	Annual[7], tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
Base Case Scenario									**Base Case Scenario**		
CO	2.99	g/hp-hr	0	44,338	0.9	0	0	0.25	0	0	0.007
NO_x	9.81	g/hp-hr	0	44338		0	0	8.18	0	0	0.235
$PM_{2.5}$	1.26	g/hp-hr	0	44338	0.85	0	0	0.16	0	0	0.005
PM_{10}	1.26	g/hp-hr	0	44338	0.85	0	0	0.16	0	0	0.005
SO_2	0.000030	lb/lb fuel	0	44338		0	0	4.71E-03	0	0	1.354E-04
VOC	1.48	g/hp-hr	0	44338	0.9	0	0	0.12	0	0	3.452E-03
Lead	0.000029	lb/MMBtu	0	44338		0	0	8.56E-05	0	0	2.462E-06
Alternative Scenario #1									**Alternative Scenario #1**		
CO	2.99	g/hp-hr	352	44,338	0.9	0.16	3.96	0.25	0.02	0.021	0.007
NO_x	9.81	g/hp-hr	352	44,338		5.41	129.76	8.18	0.682	0.681	0.235
$PM_{2.5}$	1.26	g/hp-hr	352	44,338	0.85	0.10	2.50	0.16	0.013	0.013	0.005
PM_{10}	1.26	g/hp-hr	352	44,338	0.85	0.10	2.50	0.16	0.013	0.013	0.005
SO_2	0.000030	lb/lb fuel	352	44,338		3.11E-03	7.47E-02	4.71E-03	3.92E-04	3.92E-04	1.35E-04
VOC	1.48	g/hp-hr	352	44,338	0.9	0.08	1.96	0.12	1.01E-02	1.03E-02	3.45E-03
Lead	0.000029	lb/MMBtu	352	44,338		5.66E-05	1.36E-03	8.56E-05	7.13E-06	7.13E-06	2.46E-06
Alternative Scenario #2									**Alternative Scenario #2**		
CO	2.99	g/hp-hr	704	44,338	0.9	0.16	7.91	0.25	0.02	0.042	0.007
NO_x	9.81	g/hp-hr	704	44,338		5.41	259.53	8.18	0.682	1.363	0.235
$PM_{2.5}$	1.26	g/hp-hr	704	44,338	0.85	0.10	5.00	0.16	0.013	0.026	0.005
PM_{10}	1.26	g/hp-hr	704	44,338	0.85	0.10	5.00	0.16	0.013	0.026	0.005
SO_2	0.000030	lb/lb fuel	704	44,338		3.11E-03	0.15	4.71E-03	3.92E-04	7.87E-04	1.35E-04
VOC	1.48	g/hp-hr	704	44,338	0.9	0.08	3.92	0.12	1.01E-02	2.06E-02	3.45E-03
Lead	0.000029	lb/MMBtu	704	44,338		5.66E-05	2.72E-03	8.56E-05	7.13E-06	1.43E-05	2.46E-06

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 2 tests
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 4 tests
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, 2-34 and 2-35, max of 4 tests (PM emis.)
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 2 tests
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 4
2 Engine rating per permit application dated 01-18-10, Appendix A, page 4
3 Fuel usage per permit application dated 01-18-10, Appendix A, page 4
0.415 lb/hp-hr
4 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, March 12, 2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 Daily maximum operation and operating scenarios are based on permit application dated 01-18-10, Appendix A, page 4
7 Daily and annual maximum fuel usage is for both engines, in aggregate: 44,338 gallons
8 Annual maximum fuel usage limit is for all operating scenarios in aggregate.

g/kW-hr
0.40096
13.1552
0.25345
0.25345
0.19847
3.9E-05

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-14-15	Deck Cranes
Make/Model[1]:	Caterpillar D343	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	365	hp
Maximum Hourly Fuel Use[3]:	20.76	gallons/hour
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC	

Hourly and daily emissions are on a per-engine basis. Annual emissions are for both deck cranes in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[6, 8] Daily (hrs)	Maximum Operation[6, 8] Annual (gal)[8]	Control Efficiency[4, 5]	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual[8], tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	593.6	g/hr	24	63,661	0.9	0.13	3.12	0.20	0.016	0.016	0.006
NO_x	2810.9	g/hr	24	63,661		6.2	148.80	9.50	0.781	0.781	0.273
$PM_{2.5}$	129.8	g/hr	24	63,661	0.85	0.04	0.96	0.07	0.005	0.005	0.002
PM_{10}	129.8	g/hr	24	63,661	0.85	0.04	0.96	0.07	0.005	0.005	0.002
SO_2	0.000030	lb/lb fuel	24	63,661		4.41E-03	0.11	6.76E-03	5.55E-04	5.55E-04	1.94E-04
VOC	172.6	g/hr	24	63,661	0.9	0.04	0.96	0.06	5.04E-03	5.04E-03	1.68E-03
Lead	0.000029	lb/MMBtu	24	63,661		8.01E-05	1.92E-03	1.23E-04	1.01E-05	1.01E-05	3.53E-06

Emissions Factor References

CO	From Caterpillar, See attachment to e-mail dated April 6, 2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair)[7]
NO_x	From Caterpillar, See attachment to e-mail dated April 6, 2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair)[7]
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Caterpillar, See attachment to e-mail dated April 6, 2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair)[7]
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Caterpillar, See attachment to e-mail dated April 6, 2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair)[7]
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 5
2 Engine rating per permit application dated 01-18-10, Appendix A, page 5
3 From Caterpillar, See attachment to e-mail dated April 6, 2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair)[4]
244.8 g/kW-hr converted based on engine rating, and watts/hp and g/lb conversions
4 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, March 12, 2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 Maximum operation per season is based on an owner requested limit of: 63661 gallons
Per permit application dated 01-18-10, Appendix A, page 4
7 As exact engine specification was not available, value used was highest of similarly rated engine configuration
8 Annual fuel usage and annual emissions are for both crane engines aggregated.

g/kW-hr
0.21664
10.3322
0.06666
0.06666
0.06666
0.00013

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-16-17 Cementing Unit
Make/Model[1]:	Detroit 8V-71N
Fuel:	Liquid distillate, #1 or #2
Rating[2]:	335 hp
Maximum Hourly Fuel Use[3]:	139 lbs/hour
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC

Emissions are on a per engine basis at 100% load

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[6]		Control Efficiency[4, 5]	Potential to Emit[6]			Potential to Emit in g/sec	
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	g/kW-hr
CO	2.99	g/hp-hr			0.9	0.22			0.028	0.40096
NO_x	9.81	g/hp-hr				7.25			0.913	13.1552
$PM_{2.5}$	1.26	g/hp-hr			0.85	0.14			0.018	0.25345
PM_{10}	1.26	g/hp-hr			0.85	0.14			0.018	0.25345
SO_2	0.000030	lb/lb fuel				4.17E-03			5.26E-04	
VOC	1.48	g/hp-hr			0.9	0.11			1.39E-02	0.19847
Lead	0.000029	lb/MMBtu				7.58E-05			9.56E-06	

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 2 tests
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 4 tests
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, 2-34 and 2-35, max of 4 tests (PM emis.)
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 2 tests
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 6
2 Engine rating per permit application dated 01-18-10, Appendix A, page 6
3 Fuel usage permit application dated 01-18-10, Appendix A, page 6
0.415 lb/hp-hr
4 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, March 12, 2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 See page 11 for daily and annual emissions

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-18	Cementing Unit
Make/Model[1]:	GM 3-71	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	147	hp
Maximum Hourly Fuel Use[3]:	61	lbs/hour
Control Equipment:	Clean Air Systems PERMIT[TM] Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC	

Emissions are on a per-engine basis.

Pollutant	Emission Factors[6]	Emission Factor Units	Maximum Hours of Operation[7]		Control Efficiency[4, 5]	Potential to Emit[7]			Potential to Emit in g/sec	
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	g/kW-hr
CO	6.55	g/hp-hr			0.9	0.21			0.026	0.87836
NO_x	11.72	g/hp-hr				3.8			0.479	15.7165
$PM_{2.5}$	1.92	g/hp-hr			0.85	0.09			0.011	0.38621
PM_{10}	1.92	g/hp-hr			0.85	0.09			0.011	0.38621
SO_2	0.000030	lb/lb fuel				1.83E-03			2.31E-04	
VOC	2.01	g/hp-hr			0.9	0.07			8.82E-03	0.26954
Lead	0.000029	lb/MMBtu				3.33E-05			4.19E-06	

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35[6]
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35[6]
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35[6] (PM emissions)
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35[6]
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 7
2 Engine rating per permit application dated 01-18-10, Appendix A, page 7
3 Fuel usage permit application dated 01-18-10, Appendix A, page 7
0.415 lb/hp-hr
4 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, March 12, 2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 The 71 series engines were a product of the Detroit Diesel Engine Division of General Motors
This engine is a 3-cylinder version of this family of engine - see 4/9/2009 e-mail from Air Sciences (Sabrina Pryor) to EPA (Pat Nair)
For this emission inventory, emission factors used are the highest for a 71 series engine
7 See page 11 for daily and annual emissions

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-19	Logging Winch
Make/Model[1]:	Caterpillar C7	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	250	hp
Maximum Hourly Fuel Use[3]:	93	lbs/hour
Control Equipment:	None	

Emissions are on a per-engine basis.

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[4]		Control Efficiency[5]	Potential to Emit[4]			Potential to Emit in g/sec	
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	g/kW-hr
CO	3.5	g/kW-h			0.8	0.29			0.037	0.7
NO_x	4.0	g/kW-h				1.64			0.207	4
$PM_{2.5}$	0.2	g/kW-h			0.85	0.01			0.001	0.03
PM_{10}	0.2	g/kW-h			0.85	0.01			0.001	0.03
SO_2	0.000030	lb/lb fuel				2.79E-03			3.52E-04	
VOC	4.0	g/kW-h				1.64			2.07E-01	4
Lead	0.000029	lb/MMBtu				5.08E-05			6.39E-06	

Emissions Factor References

CO	From Tier 3 emission limit in 40 CFR 89.112
NO_x	From Tier 3 emission limit in 40 CFR 89.112 (Limit is for NOx and NMHC, in aggregate)
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	Assumed to be the same as PM from Tier 3 emission limit in 40 CFR 89.112
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Tier 3 emission limit in 40 CFR 89.112 (Limit is for NOx and NMHC, in aggregate)
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 8
2 Engine rating per permit application dated 01-18-10, Appendix A, page 8
3 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
4 See page 11 for daily and annual emissions
5 Control efficiency is based on use of CDPF

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-20	Logging Winch		
Make/Model[1]:	John Deere PE4020TF270D			
Fuel:	Liquid distillate, #1 or #2			
Rating[2]:	35	hp	converted from	
Maximum Hourly Fuel Use[3]:	13.0	lbs/hour		
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC			

Emissions are on a per-engine basis.

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[7] Daily	Maximum Hours of Operation[7] Annual	Control Efficiency[4, 5]	Potential to Emit[7] Hourly, lb/hr	Potential to Emit[7] Daily, lb/day	Potential to Emit[7] Annual, tpy	Potential to Emit in g/sec One-Hour	g/kW-hr
CO	5.5	g/kW-hr			0.9	0.03			0.004	0.55
NO_x	7.5	g/kW-hr				0.43			0.054	7.5
$PM_{2.5}$	0.60	g/kW-hr			0.85	0.01			0.001	0.09
PM_{10}	0.60	g/kW-hr			0.85	0.01			0.001	0.09
SO_2	0.000030	lb/lb fuel				3.91E-04			4.92E-05	
VOC	7.5	g/kW-hr			0.9	0.04			5.04E-03	0.75
Lead	0.000029	lb/MMBtu				7.11E-06			8.95E-07	

Emissions Factor References

CO	From Tier 2 emission limit in 40 CFR 89.112
NO_x	From Tier 2 emission limit in 40 CFR 89.112
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	Assumed to be the same as PM from Tier 2 emission limit in 40 CFR 89.112
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Tier 2 emission limit in 40 CFR 89.112
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59	g/lb
2,000	lbs/ton
745.7	watts/hp
7.076	lbs/gal
133,098	Btu/gal

Footnotes/Assumptions

1 Engine specification per permit application dated 01-18-10, Appendix A, page 9
2 Engine rating per permit application dated 01-18-10, Appendix A, page 9
3 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
4 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, March 12, 2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
7 See page 11 for daily and annual emissions

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-16-20 Cementing Units and Logging Winches
Make/Model:	See pages A-7 - A-10 for details
Fuel:	Liquid distillate, #1 or #2
Rating:	See pages A-7 - A-10 for details
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC on all engines except FD-19

Emissions are for all cementing unit and logging winch engines in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[1]		Control Efficiency[3]	Potential to Emit[2]			Potential to Emit in g/sec	
			Daily (gal)	Annual (gal)		Hourly, lb/hr	Daily, lb/day	Annual, tpy	24-Hour	365-Day
CO	0.66	g/hp-hr	320	53,760			7.88	0.66	0.041	0.019
NO_x	11.72	g/hp-hr	320	53,760			140.98	11.84	0.74	0.341
$PM_{2.5}$	0.288	g/hp-hr	320	53,760			3.46	0.29	0.018	0.008
PM_{10}	0.288	g/hp-hr	320	53,760			3.46	0.29	0.018	0.008
SO_2	0.000030	lb/lb	320	53,760			0.07	5.71E-03	3.57E-04	1.64E-04
VOC	2.98	g/hp-hr	320	53,760			35.85	3.01	1.88E-01	8.66E-02
Lead	0.000029	lb/MMBtu	320	53,760			1.24E-03	1.04E-04	6.48E-06	2.98E-06

Emissions Factor References

CO	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
NO_x	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59	g/lb	
2,000	lbs/ton	
745.7	watts/hp	
7.076	lbs/gal	
133,098	Btu/gal	
0.415	lb/hp-hr	Fuel usage is minimum of values for five engines (FD16-20)

Footnotes/Assumptions

1 Daily fuel usage is per applicant request dated 9/17/2009: 320 gallons per day
2 Emissions are for all cementing unit and logging winch engines in aggregate.
3 Emission factors used on this page are controlled (either CDPF or Tier3)

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-21-22	Heat Boilers
Make/Model[1]:	Clayton 200	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	7.97	MMBtu/hr
Maximum Hourly Fuel Use[3]:	424	lbs/hour
Control Equipment:	None	

Emissions are on a per-boiler basis at 100% load

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec			
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day	lb/MMBtu
CO	14.8	lbs/day	24	4,032		0.62	14.8	1.25	0.078	0.078	0.036	0.07779
NO_x	38.50	lbs/day	24	4,032		1.6	38.50	3.23	0.202	0.202	0.093	0.20075
$PM_{2.5}$	4.50	lbs/day	24	4,032		0.19	4.50	0.38	0.024	0.024	0.011	0.02384
PM_{10}	4.50	lbs/day	24	4,032		0.19	4.50	0.38	0.024	0.024	0.011	0.02384
SO_2	0.000030	lb/lb fuel	24	4,032		1.27E-02	0.31	2.56E-02	1.60E-03	1.63E-03	7.37E-04	
VOC	0.27	lbs/day	24	4,032		0.01	0.27	0.02	1.26E-03	1.42E-03	5.75E-04	0.00125
Lead	0.000009	lb/MMBtu	24	4,032		7.17E-05	1.72E-03	1.45E-04	9.04E-06	9.04E-06	4.16E-06	

Emissions Factor References

CO	From Clayton. See permit application dated 2-23-2009, Appendix B, page 29
NO_x	From Clayton. See permit application dated 2-23-2009, Appendix B, page 29
$PM_{2.5}$	$PM_{2.5}$ emissions assumed to be same as PM_{10} emissions
PM_{10}	From Clayton. See permit application dated 2-23-2009, Appendix B, page 29
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	From Clayton. See permit application dated 2-23-2009, Appendix B, page 29
Lead	AP-42, Table 1.3-10

Conversions Used

2,000 lbs/ton
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Boiler specification per permit application dated 01-18-10, Appendix A, page 10
2 Boiler rating per permit application dated 01-18-10, Appendix A, page 10
3 Fuel usage converted based on boiler rating, fuel density and fuel heat content.

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit:	FD-23	Incinerator			
Make/Model[1]:	TeamTec GS500C				
Fuel[2]:	Waste material				
Rating[3]:	276	lbs/hour	converted from	125	kg/hr
Control Equipment:	None				

Hourly emissions are for one incinerator at 100% load

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation, lbs of Waste[4] Daily	Annual[5]	Control Efficiency	Potential to Emit Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
Base Case Scenario									**Base Case Scenario**		
CO	31	lbs/ton	1300	50,400		4.28	20.15	0.39	0.539	0.106	0.011
NO_x	5	lbs/ton	1300	50,400		0.69	3.25	0.06	0.087	0.017	0.002
$PM_{2.5}$	7.00	lbs/ton	1300	50,400		0.97	4.55	0.09	0.122	0.024	0.003
PM_{10}	8.2	lbs/ton	1300	50,400		1.13	5.33	0.10	0.143	0.028	0.003
SO_2	2.5	lbs/ton	1300	50,400		0.35	1.63	0.03	4.35E-02	8.53E-03	9.06E-04
VOC	3	lbs/ton	1300	50,400		0.41	1.95	0.04	5.22E-02	1.02E-02	1.09E-03
Lead	0.213	lbs/ton	1300	50,400		0.03	0.14	2.68E-03	3.70E-03	7.27E-04	7.72E-05
Alternative Scenario #1									**Alternative Scenario #1**		
CO	31	lbs/ton	800	50,400		4.28	12.40	0.39	0.539	0.065	0.011
NO_x	5	lbs/ton	800	50,400		0.69	2.00	0.06	0.087	0.01	0.002
$PM_{2.5}$	7.00	lbs/ton	800	50,400		0.97	2.80	0.09	0.122	0.015	0.003
PM_{10}	8.2	lbs/ton	800	50,400		1.13	3.28	0.10	0.143	0.017	0.003
SO_2	2.5	lbs/ton	800	50,400		0.35	1.00	0.03	4.35E-02	5.25E-03	9.06E-04
VOC	3	lbs/ton	800	50,400		0.41	1.20	0.04	5.22E-02	6.30E-03	1.09E-03
Lead	0.213	lbs/ton	800	50,400		0.03	0.09	2.68E-03	3.70E-03	4.47E-04	7.72E-05
Alternative Scenario #2									**Alternative Scenario #2**		
CO	31	lbs/ton	300	50,400		4.28	4.65	0.39	0.539	0.024	0.011
NO_x	5	lbs/ton	300	50,400		0.69	0.75	0.06	0.087	0.004	0.002
$PM_{2.5}$	7.00	lbs/ton	300	50,400		0.97	1.05	0.09	0.122	0.006	0.003
PM_{10}	8.2	lbs/ton	300	50,400		1.13	1.23	0.10	0.143	0.006	0.003
SO_2	2.5	lbs/ton	300	50,400		0.35	0.38	0.03	4.35E-02	1.97E-03	9.06E-04
VOC	3	lbs/ton	300	50,400		0.41	0.45	0.04	5.22E-02	2.36E-03	1.09E-03
Lead	0.213	lbs/ton	300	50,400		0.03	0.03	2.68E-03	3.70E-03	1.68E-04	7.72E-05

Emissions Factor References

CO	AP-42 Table 2.2-1, multiple hearth
NO_x	AP-42 Table 2.2-1, multiple hearth
$PM_{2.5}$	Owner requested limit per Shell permit application dated 01-18-10
PM_{10}	Owner requested limit per Shell permit application dated 01-18-10
SO_2	Owner requested limit per Shell permit application dated 01-18-10
VOC	AP-42 Table 2.1-12, industrial/commercial multi-chamber
Lead	AP-42 Table 2.1-2, mass burn and modular excess air

Conversions Used

453.59 g/lb
2,000 lbs/ton

Footnotes/Assumptions

1 Incinerator specification per permit application dated 01-18-10, Appendix A, page 11
2 Incinerator can burn municipal wate or sewage - emission factors are maximum for these two waste feeds
3 Incinerator rating per permit application dated 01-18-10, Appendix A, page 11
4 Daily and annual usage limits, and alternative scenarios are based on owner requested limits per Shell request dated 9/17/2009
5 Annual maximum waste incinerated is for all operating scenarios in aggregate, and is based on an av 300 lbs/day

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: FD-31 Supply Ship at Discoverer
Fuel: Liquid distillate, #1 or #2

Equipment Type: Internal Combustion Engine
Rating[1]: 292 hp

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[2] Daily	Maximum Hours of Operation[2] Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	0.95	lb/MMBtu	12	96		1.94	23.30	0.09	0.245	0.122	2.68E-03
NO_x	4.41	lb/MMBtu	12	96		9.01	108.17	0.43	1.136	0.568	1.24E-02
$PM_{2.5}$	0.31	lb/MMBtu	12	96		0.63	7.60	0.03	0.080	0.040	8.75E-04
PM_{10}	0.31	lb/MMBtu	12	96		0.63	7.60	0.03	0.080	0.040	8.75E-04
SO_2	0.000030	lb/lb fuel	12	96		3.26E-03	0.04	1.56E-04	0.000	0	4.50E-06
VOC	0.35	lb/MMBtu	12	96		0.72	8.58	0.03	0.090	0.045	9.88E-04
Lead	0.000029	lb/MMBtu	12	96		5.93E-05	7.11E-04	2.85E-06	7.47E-06	3.73E-06	8.18E-08

Emissions Factor References

CO, NO_x, $PM_{2.5}$, PM_{10}, VOC From AP-42, Section 3.3, Table 3.3-1
SO_2 Based on fuel sulfur content: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Equipment population and rating based on vessel Jim Kilabuk per permit application dated 01-18-10 Appendix A, page 17
2 Owner requested limits per e-mail and attachment of 5/22/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair):
Propulsion engines not operated while berthed at Frontier Discoverer
Equivalent to only one generator to be operated - total hp: 292 hp
Brake specific fuel consumption (from AP-42): 7000 Btu/hp-hr
3 Sulfur content of fuel: 0.0019 by weight

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #1
Fuel: Liquid distillate, #1 or #2, and waste materials for incinerator

Equipment Type: Internal Combustion Engines
Aggregate Rating, Propulsion Engines[1]: 28400 hp
Max. Aggregate Limit, Propulsion Engines[2]: 22720 hp
Aggregate Rating, Generation Engines[1]: 2800 hp
Max. Aggregate Limit, All Engines[2]: 19,030 kW mechanical kW
Max. Aggregate Limit, All Engines[3]: 17,508 kWe electrical kW

			Maximum Operation (kWe-hr)			Potential to Emit[3]			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	3.35	g/kW-hr	420,188	28,233,704		140.36	3,368.64	113.17	17.685	17.685	3.256
NO_x	5.876	lb/MMBtu	420,188	28,233,704		1049.69	25,192.53	846.38	132.258	132.258	24.347
$PM_{2.5}$	0.22	lb/MMBtu	420,188	28,233,704		39.30	943.22	31.69	4.952	4.952	0.912
PM_{10}	0.249	lb/MMBtu	420,188	28,233,704		44.48	1067.55	35.87	5.605	5.605	1.032
SO_2	0.000030	lb/lb	420,188	28,233,704		0.28	6.84	0.23	0.036	0.036	0.007
VOC	0.60	g/kW-hr	420,188	28,233,704		25.17	604.15	20.30	3.172	3.172	0.584
Lead	2.90E-05	lb/MMBtu	420,188	28,233,704		5.18E-03	0.12	4.18E-03	6.53E-04	6.53E-04	1.20E-04

Emissions Factor References
CO, VOC From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25
NOx Emission factors relied upon by Shell in 01-18-10 permit application, Appendix A, page 17
$PM_{2.5}$, PM_{10} Emission factors relied upon by Shell in 01-18-10 permit application, Appendix A, page 17
SO_2 Based on fuel sulfur content: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Aggregate Rating, Heat Boiler(s)[1]: 10.00 MMBtu/hr
Maximum Hourly Fuel Use[5]: 75 gallons/hour

			Maximum Hours of Operation			Potential to Emit			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	5	$lb/10^3$ gal	24	4,032		3.76E-01	9.02	0.76	0.047	0.047	0.022
NO_x	20.00	$lb/10^3$ gal	24	4,032		1.50E+00	36.06	3.03	0.189	0.189	0.087
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		2.48E-01	5.95	0.50	0.031	0.031	0.014
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		2.48E-01	5.95	0.50	0.031	0.031	0.014
SO_2	0.213	$lb/10^3$ gal	24	4,032		1.60E-02	0.38	0.03	2.02E-03	2.02E-03	9.28E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		2.55E-02	0.61	0.05	3.22E-03	3.22E-03	1.48E-03
Lead	0.000009	lb/MMBtu	24	4,032		9.00E-05	0.00	1.81E-04	1.13E-05	1.13E-05	5.22E-06

Emissions Factor References
CO, NOx AP-42 Table 1.3-1, boilers < 100 MMBtu/hr
$PM_{2.5}$ Assumed to be same as for PM_{10}
PM_{10} AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)
SO_2 AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel: 0.000015 by weight
VOC AP-42 Table 1.3-3, commercial boilers
Lead AP-42, Table 1.3-10

Equipment Type: Incinerator
Aggregate Rating[1]: 154.00 lb/hr Emissions are for all incinerators on board the vessel

			Maximum Hours of Operation			Potential to Emit			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	300	lbs/ton	24	4032		23.10	554.40	46.57	2.911	2.911	1.34
NO_x	3	lbs/ton	24	4032		0.23	5.54	0.47	0.029	0.029	0.014
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.70	16.82	1.41	0.088	0.088	0.041
PM_{10}	13.3	lbs/ton	24	4032		1.02	24.58	2.06	0.129	0.129	0.059
SO_2	2.5	lbs/ton	24	4032		0.19	4.62	0.39	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.70	184.80	15.52	0.97	0.97	0.446
Lead	0.213	lbs/ton	24	4032		1.64E-02	3.94E-01	3.31E-02	2.07E-03	2.07E-03	9.51E-04

Emissions Factor References
CO, NOx, SO_2, VOC AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}: Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #1
(CONTINUED)

Total Emissions for Icebreaker #1

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
163.84	3932.06	160.50	20.643	20.643	4.617
1051.42	25234.14	849.88	132.476	132.476	24.448
40.25	965.99	33.60	5.071	5.071	0.967
45.75	1098.08	38.43	5.765	5.765	1.105
0.49	11.84	0.65	0.062	0.062	0.019
32.90	789.56	35.87	4.145	4.145	1.032
0.02	0.52	3.74E-02	2.73E-03	2.73E-03	1.08E-03

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Maximum equipment ratings per e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair):

Propulsion engines:	28400 hp at maximum	80% load
Generator engines:	2800 hp	
Boilers:	10 MMBtu/hr	
Incinerator:	154 lb/hr	

2 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content

3 Minimum generator efficiency based on conservative data from Shell submittal to EPA dated 11/23/2009 (pages 6 - 7):
Engine minimum generator efficiency: 92%

4 Owner requested limits:
$PM_{2.5}$ hourly emissions limit: 42.2 lbs
PM_{10} hourly emissions limit: 48.0 lbs

Exhibit 5
AEWC & ICAS

42.71826
48.3493

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #2 - Tor Viking Scenario
Fuel: Liquid distillate, #1 or #2, and waste materials for incinerator

Equipment Type:	Internal Combustion Engines		
Aggregate Rating, Propulsion Engines[1]:	17660	hp	
Max. Aggregate Limit, Propulsion Engines[2]:	14128	hp	
Aggregate Rating, Generation Engines[1]:	2336	hp	
Max. Aggregate Limit, All Engines[2]:	12,277	kW	mechanical kW
Max. Aggregate Limit, All Engines[3]:	11,786	kWe	electrical kW

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (kWe-hr) Daily	Maximum Operation (kWe-hr) Annual	Control Efficiency	Potential to Emit[4] Hourly, lb/hr	Potential to Emit[4] Daily, lb/day	Potential to Emit[4] Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	3.35	g/kW-hr	282,867	18,058,216		90.55	2173.25	69.37	11.409	11.409	1.996
NO_X	0.106	lb/gal	282,867	18,058,216		91.78	2202.82	70.31	11.565	11.565	2.023
$PM_{2.5}$	0.0573	lb/MMBtu	282,867	18,058,216		6.60	158.49	5.06	0.832	0.832	0.146
PM_{10}	0.0573	lb/MMBtu	282,867	18,058,216		6.60	158.49	5.06	0.832	0.832	0.146
SO_2	0.000030	lb/lb	282,867	18,058,216		0.18	4.41	0.14	0.023	0.023	0.004
VOC	0.60	g/kW-hr	282,867	18,058,216		16.24	389.76	12.44	2.046	2.046	0.358
Lead	2.90E-05	lb/MMBtu	282,867	18,058,216		3.34E-03	0.08	2.56E-03	4.21E-04	4.21E-04	7.37E-05

Emissions Factor References

CO, VOC From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25

NO_X Emission factors relied upon by Shell per 1/05/2010 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair) to establish annual, owner-requested emission limits

$PM_{2.5}$ Emission factors relied upon by Shell in 01-18-10 permit application, Appendix A, page 18

PM_{10} Emission factors relied upon by Shell in 01-18-10 permit application, Appendix A, page 18

SO_2 Based on fuel sulfur content: 0.000015 by weight

Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Aggregate Rating, Heat Boiler(s)[1]:	1.37	MMBtu/hr
Maximum Hourly Fuel Use[5]:	10	gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	Maximum Hours of Operation Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	5	$lb/10^3$ gal	24	4,032		5.15E-02	1.24	0.10	0.006	0.006	0.003
NO_x	20.00	$lb/10^3$ gal	24	4,032		0.21	4.94	0.42	0.026	0.026	0.012
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		0.03	0.82	0.07	0.004	0.004	0.002
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		0.03	0.82	0.07	0.004	0.004	0.002
SO_2	0.213	$lb/10^3$ gal	24	4,032		2.19E-03	0.05	4.42E-03	2.76E-04	2.76E-04	1.27E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		3.50E-03	0.08	0.01	4.41E-04	4.41E-04	2.03E-04
Lead	0.000009	lb/MMBtu	24	4,032		1.23E-05	2.96E-04	2.49E-05	1.55E-06	1.55E-06	7.15E-07

Emissions Factor References

CO, NOx AP-42 Table 1.3-1, boilers < 100 MMBtu/hr

$PM_{2.5}$ Assumed to be same as for PM_{10}

PM_{10} AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)

SO_2 AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel: 0.000015 by weight

VOC AP-42 Table 1.3-3, commercial boilers

Lead AP-42, Table 1.3-10

Equipment Type:	Incinerator		
Aggregate Rating[1]:	151.23	lb/hr	Emissions are for all incinerators on board the vessel

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	Maximum Hours of Operation Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	300	lbs/ton	24	4032		22.68	544.43	45.73	2.858	2.858	1.315
NO_x	3	lbs/ton	24	4032		0.23	5.44	0.46	0.029	0.029	0.013
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.69	16.51	1.39	0.087	0.087	0.04
PM_{10}	13.3	lbs/ton	24	4032		1.01	24.14	2.03	0.127	0.127	0.058
SO_2	2.5	lbs/ton	24	4032		0.19	4.54	0.38	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.56	181.48	15.24	0.953	0.953	0.438
Lead	0.213	lbs/ton	24	4032		1.61E-02	3.87E-01	3.25E-02	2.03E-03	2.03E-03	9.34E-04

Emissions Factor References

CO, NOx, SO_2, VOC AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber

$PM_{2.5}$, PM_{10}: Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).

Lead AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Shell Offshore Inc.
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Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #2 - Tor Viking Scenario
(CONTINUED)

Total Emissions for Tor Viking

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
113.29	2718.91	115.20	14.274	14.274	3.314
92.22	2213.20	71.19	11.619	11.619	2.048
7.33	175.82	6.52	0.923	0.923	0.187
7.64	183.44	7.16	0.963	0.963	0.206
0.38	9.00	0.53	0.047	0.047	0.015
23.81	571.32	27.69	2.999	2.999	0.796
1.95E-02	0.47	3.51E-02	2.45E-03	2.45E-03	1.01E-03

Maximum Emissions for Icebreaker#2 (max of Tor Viking and Hull 247)

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
234.48	5627.51	237.17	29.544	29.544	6.822
92.22	2213.20	71.19	11.619	11.619	2.048
11.37	272.87	11.15	1.433	1.433	0.321
11.69	280.49	11.79	1.473	1.473	0.339
0.51	12.19	0.68	0.064	0.064	0.019
23.81	571.32	27.69	2.999	2.999	0.796
2.14E-02	0.51	3.73E-02	2.69E-03	2.69E-03	1.07E-03

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Maximum equipment ratings per Shell submittal to EPA dated 9/17/2009:
Propulsion engines: 17660 hp at maximum
Non-propulsion Generator engines: 2336 hp
Boilers: 1.37 MMBtu/hr
Incinerator: 151.23 lb/hr
2 Maximum operating limit Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines, in aggregate: 80%
3 Minimum generator efficiency based on MaK engine specs per Shell submittal to EPA dated 11/23/2009 (Attachment B, page 14):
Propulsion engine minimum generator efficiency: 96%
4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #2 - Hull 247
Fuel: Liquid distillate, #1 or #2, and waste materials for incinerator

Equipment Type: Internal Combustion Engines
Aggregate Rating, Propulsion Engines[1]: 24000 kW mechanical kW
Max. Aggregate Limit, Propulsion Engines[2]: 19200 kW mechanical kW
Max. Aggregate Limit, Propulsion Engines[3]: 17664 kWe electrical kW

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (kWe-hr)		Control Efficiency	Potential to Emit[4]			Potential to Emit in g/sec			
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day	
CO	5.0	g/kW-hr	423,936	31,904,074		211.64	5,079.48	191.13	26.667	26.667	5.498	
NO_x	1.8	g/kW-hr	423,936	31,904,074		76.19	1,828.61	68.81	9.6	9.6	1.979	70.48
$PM_{2.5}$	0.25	g/kW-hr	423,936	31,904,074		10.58	253.97	9.56	1.333	1.333	0.275	
PM_{10}	0.25	g/kW-hr	423,936	31,904,074		10.58	253.97	9.56	1.333	1.333	0.275	
SO_2	0.000012	lb/hp-hr	423,936	31,904,074		0.31	7.50	0.28	0.039	0.039	0.008	
VOC	0.19	g/kW-hr	423,936	31,904,074		8.04	193.02	7.26	1.013	1.013	0.209	
Lead	2.90E-05	lb/MMBtu	423,936	31,904,074		5.23E-03	0.13	4.72E-03	6.59E-04	6.59E-04	1.36E-04	

Emissions Factor References
CO, NO_x, PM, VOC Marine engine emission limits in 40 CFR 1042.101 (engines of at least 700 kW). All HC assumed to be VOC
Owner requested annual NOx limits per 9/17/2009 submittal from Shell
$PM_{2.5}$, PM_{10} $PM_{2.5}$ and PM_{10} emission factors assumed to be same as PM
SO_2 AP-42 Table 3.4-1 and Sulfur content of fuel: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Aggregate Rating, Heat Boiler(s)[1]: 4.00 MMBtu/hr
Maximum Hourly Fuel Use[6]: 30 gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	5	$lb/10^3$ gal	24	4,032		0.15	3.6	0.30	0.019	0.019	0.009
NO_x	20.00	$lb/10^3$ gal	24	4,032		0.60	14.43	1.21	0.076	0.076	0.035
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		0.10	2.38	0.20	0.012	0.012	0.006
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		0.10	2.38	0.20	0.012	0.012	0.006
SO_2	0.213	$lb/10^3$ gal	24	4,032		6.40E-03	0.15	0.01	8.07E-04	8.07E-04	3.71E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		0.01	0.25	0.02	1.29E-03	1.29E-03	5.93E-04
Lead	0.000009	lb/MMBtu	24	4,032		3.60E-05	8.64E-04	7.26E-05	4.54E-06	4.54E-06	2.09E-06

Emissions Factor References
CO, NOx AP-42 Table 1.3-1, boilers < 100 MMBtu/hr
$PM_{2.5}$ Assumed to be same as for PM_{10}
PM_{10} AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)
SO_2 AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel: 0.000015 by weight
VOC AP-42 Table 1.3-3, commercial boilers
Lead AP-42, Table 1.3-10

Equipment Type: Incinerator
Aggregate Rating[1]: 151.23 lb/hr Emissions are for all incinerators on board the vessel

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	300	lbs/ton	24	4032		22.68	544.43	45.73	2.858	2.858	1.315
NO_x	3	lbs/ton	24	4032		0.23	5.44	0.46	0.029	0.029	0.013
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.69	16.51	1.39	0.087	0.087	0.04
PM_{10}	13.3	lbs/ton	24	4032		1.01	24.14	2.03	0.127	0.127	0.058
SO_2	2.5	lbs/ton	24	4032		0.19	4.54	0.38	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.56	181.48	15.24	0.953	0.953	0.438
Lead	0.213	lbs/ton	24	4032		1.61E-02	3.87E-01	3.25E-02	2.03E-03	2.03E-03	9.34E-04

Emissions Factor References
CO, NOx, SO_2, VOC AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}: Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #2 - Hull 247
(CONTINUED)

Total Emissions for Hull 247

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
234.48	5627.51	237.17	29.544	29.544	6.822
77.02	1848.48	70.48	9.704	9.704	2.027
11.37	272.87	11.15	1.433	1.433	0.321
11.69	280.49	11.79	1.473	1.473	0.339
0.51	12.19	0.68	0.064	0.064	0.019
15.61	374.74	22.52	1.967	1.967	0.648
2.14E-02	0.51	3.73E-02	2.69E-03	2.69E-03	1.07E-03

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Maximum equipment ratings per Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines: 24000 kW mechanical
Non-propulsion Generator engines: 0 hp
Boilers: 4 MMBtu/hr
Incinerator: 151.23 lb/hr
2 Maximum operating limit Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines, in aggrega 80%
3 Minimum generator efficiency based on Shell submittal to EPA dated 11/23/2009:
Propulsion engine minimum generator efficiency: 92%
4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
5 Shell has requested an annual NOx limit of 58.39 tpy per 9/17/2009 submittal
6 Fuel usage converted based on boiler rating and fuel heat content.

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit:	Supply Ship - Generic	
Fuel:	Liquid distillate, #1 or #2	
Equipment Type:	Internal Combustion Engines	
Aggregate Rating[1]:	7784 hp	
Owner Requested Limit (Daily, Annual)[2]:	6344 hp	Emissions are for all engines in aggregate.
Maximum Hourly Fuel Use[2]:	334 gallons/hour	

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[4] Daily	Annual	Control Efficiency	Potential to Emit Hourly, lb/hr[1]	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	3.35	g/kW-hr	4	32		34.89	139.57	0.56	4.396	0.733	0.016
NO_x	25.40	g/kW-hr	4	32		264.92	1059.68	4.24	33.379	5.563	0.122
$PM_{2.5}$	1.54	g/kW-hr	4	32		16.06	64.25	0.26	2.024	0.337	0.007
PM_{10}	1.92	g/kW-hr	4	32		20.02	80.10	0.32	2.523	0.421	0.009
SO_2	0.000030	lb/lb	4	32		0.07	0.28	1.13E-03	0.009	0.001	0
VOC	0.60	g/kW-hr	4	32		6.26	25.03	0.10	0.788	0.131	0.003
Lead	0.000029	lb/MMBtu	4	32		1.29E-03	5.16E-03	2.06E-05	1.62E-04	2.71E-05	5.93E-07

Emissions Factor References

All pollutants except lead From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25

SO_2 Sulfur content of fuel: 0.000015 by weight

Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Equipment population and rating based on vessel Jim Kilabuk per permit application dated February 23, 2009, Appendix B, page 15

Propulsion Engines:	7200 hp
Both generators:	584 hp
Bow thrusters not used:	0 hp
	7784 hp

2 Owner requested limits per e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair) and 5/27/2009 phone call between Air Sciences (Rodger Steen) and EPA (Pat Nair):

Propulsion Engines limited to 2 engines at no more than 80% load, i.e.	5760 hp
Both generators at full load - total hp:	584 hp
Bow thrusters not used:	0 hp

3 Brake specific fuel combustion from AP-42: 7000 Btu/hp-hr

4 Owner requested limits per permit Application, Appendix A, page 16
based on a 4-hour round trip from the 25-mile distance to the Discoverer and 8 annual trips

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Beaufort Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Fleet Unit: Oil Spill Response Main Ship - Nanuq
Fuel: Liquid distillate, #1 or #2, and waste materials for incinerator

Equipment Type: Propulsion Engines - Caterpillar 3608 Internal Combustion Engines
Aggregate Rating[1]: 5420 kW

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2] Daily	Annual	Control Efficiency[5, 6]	Potential to Emit Hourly, lb/hr[3]	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	0.73	g/kW-hr	3,000	504,000	0.9	0.87	7.57	0.64	0.11	0.04	0.018
NO_X	13.62	g/kW-hr	3,000	504,000		162.70	1412.02	118.61	20.5	7.413	3.412
$PM_{2.5}$	0.17	g/kW-hr	3,000	504,000	0.85	0.30	2.64	0.22	0.038	0.014	0.006
PM_{10}	0.17	g/kW-hr	3,000	504,000	0.85	0.30	2.64	0.22	0.038	0.014	0.006
SO_2[2,4]	0.000030	lb/lb fuel	3,000	504,000		0.07	0.64	0.05	0.009	0.003	0.00
VOC	0.99	g/kW-hr	3,000	504,000	0.9	1.18	10.27	0.86	0.149	0.054	0.025
Lead	0.000029	lb/MMBtu	3,000	504,000		1.33E-03	1.16E-02	9.73E-04	1.68E-04	6.08E-05	2.80E-05

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC Permit application dated February 23, 2009, Appendix B, page 51
NOx NO_X emission factor was converted from NO to NO_2, ratio 1.53
SO_2 Sulfur content of fuel: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Equipment Type: Non-Propulsion Generator Engines
Aggregate Rating[1]: 2570 hp
Owner Requested Limit (Daily, Annual)[2]: 800 gal/day

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2] Daily	Annual	Control Efficiency[5, 6]	Potential to Emit Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	3.35	g/kW-hr	800	134,400	0.9	1.41	8.37	0.70	0.178	0.044	0.02
NO_X	25.40	g/kW-hr	800	134,400		107.32	635.21	53.36	13.522	3.335	1.535
$PM_{2.5}$	1.54	g/kW-hr	800	134,400	0.85	0.98	5.78	0.49	0.123	0.03	0.014
PM_{10}	1.92	g/kW-hr	800	134,400	0.85	1.22	7.20	0.60	0.153	0.038	0.017
SO_2	0.000030	lb/lb fuel	800	134,400		2.87E-02	1.70E-01	1.43E-02	0.004	0.001	0.00
VOC	0.60	g/kW-hr	800	134,400	0.9	0.25	1.50	0.13	0.032	0.008	0.004
Lead	0.000029	lb/MMBtu	800	134,400		5.22E-04	3.09E-03	2.59E-04	6.57E-05	1.62E-05	7.46E-06

Emissions Factor References
All pollutants except lead and SO_2 From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25
SO_2 Sulfur content of fuel: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Equipment Type: Incinerator
Aggregate Rating[1]: 125.00 lb/hr Emissions are for all incinerators on board the vessel

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	300	lbs/ton	24	4,032		18.75	450.00	37.80	2.362	2.362	1.087
NO_X	3	lbs/ton	24	4,032		0.19	4.50	0.38	0.024	0.024	0.011
$PM_{2.5}$	9.1	lbs/ton	24	4,032		0.57	13.65	1.15	0.072	0.072	0.033
PM_{10}	13.3	lbs/ton	24	4,032		0.83	19.95	1.68	0.105	0.105	0.048
SO_2	2.5	lbs/ton	24	4,032		0.16	3.75	0.32	0.02	0.02	0.01
VOC	100	lbs/ton	24	4,032		6.25	150.00	12.60	0.787	0.787	0.362
Lead	0.213	lbs/ton	24	4,032		0.01	0.32	2.68E-02	1.68E-03	1.68E-03	7.72E-04

Footnotes/Assumptions

1 Equipment population, rating and usage based on vessel Nanuq per permit application dated 01/18/10 Appendix A, page 17
Hourly emissions are based on the aggregate rating of all equipment on board except for the emergency generator

2 Owner requested limits per e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair), and Shell's updated request dated 9/17/2009:
Propulsion Engines expected to not exceed (in aggregate): 47000 kW-hr/day
Maximum fuel usage: 3000 gal/day
Generator usage expected to not exceed (in aggregate): 11,350 kW-hr/day
Maximum fuel usage: 800 gal/day

3 Fuel usage per permit application dated 2/23/2009, Appendix B, page 51 204.7 g/kW-hr

4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content

5 PM_{10} control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, 3/12/2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)

6 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems,

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Criteria Pollutant Emission Inventory

Fleet Unit: Oil Spill Response Main Ship - Point Barrow Tug
Fuel: Liquid distillate, #1 or #2

Equipment Type: Propulsion Engines - Caterpillar 3512 Internal Combustion Engines
Aggregate Rating[1]: 2100 hp[2] 1566 kw

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2] Daily	Maximum Operation (gallons)[2] Annual	Control Efficiency[5, 6]	Potential to Emit Hourly, lb/hr[3]	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	0.73	g/kW-hr	2,399	403,032		2.52	60.54	5.09	0.318	0.318	0.146
NO_X	13.62	g/kW-hr	2,399	403,032		47.01	1129.15	94.85	5.923	5.928	2.728
$PM_{2.5}$	0.17	g/kW-hr	2,399	403,032		0.59	14.10	1.18	0.074	0.074	0.034
PM_{10}	0.17	g/kW-hr	2,399	403,032		0.59	14.10	1.18	0.074	0.074	0.034
SO_2[2,4]	0.000030	lb/lb fuel	2,399	403,032		0.02	0.51	0.04	0.003	0.003	0.00
VOC	0.99	g/kW-hr	2,399	403,032		3.42	82.10	6.90	0.431	0.431	0.198
Lead	0.000029	lb/MMBtu	2,399	403,032		3.85E-04	9.26E-03	7.78E-04	4.86E-05	4.86E-05	2.24E-05

Fleet Unit: Oil Spill Response Main Ships - Point Barrow Tug and Arctic Endeavor Barge
Fuel: Liquid distillate, #1 or #2

Equipment Type: Non-Propulsion Generator Engines
Aggregate Rating[1]: 856 hp[3] 638 kw Emissions are for all generator units combined

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2] Daily	Maximum Operation (gallons)[2] Annual	Control Efficiency[5, 6]	Potential to Emit Hourly, lb/hr[3]	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	3.34	g/kW-hr	1,080	181,440		4.70	112.76	9.47	0.592	0.592	0.272
NO_X	25.40	g/kW-hr	1,080	181,440		35.74	857.50	72.03	4.504	4.502	2.072
$PM_{2.5}$	1.54	g/kW-hr	1,080	181,440		2.17	51.99	4.37	0.273	0.273	0.126
PM_{10}	1.92	g/kW-hr	1,080	181,440		2.70	64.82	5.44	0.34	0.34	0.157
SO_2[2,4]	0.000030	lb/lb fuel	1,080	181,440		0.01	0.23	0.02	0.001	0.001	0.00
VOC	0.60	g/kW-hr	1,080	181,440		0.84	20.26	1.70	0.106	0.106	0.049
Lead	0.000029	lb/MMBtu	1,080	181,440		1.74E-04	4.17E-03	3.50E-04	2.19E-05	2.19E-05	1.01E-05

1 Equipment population, rating and usage based on the permit application dated 01/18/10 Appendix A, and
01-20-10 email with Attachment from Environ (Kirk Winges) to EPA (Natasha Greaves)
2 The Point Barrow Tug has two 1050 hp propulsion engines and two 150 hp generators.
3 The Arctic Endeavor has one 350 hp crane, one 30 hp light plant, one 126 hp generator, and one 50 hp anchor guide.

Emissions Factor References

CO, NOx, SO_2, VOC	AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}	Owner requested limits e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead	AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Conversions Used

453.59	g/lb
2,000	lbs/ton
745.7	watts/hp
7.076	lbs/gal
133,098	Btu/gal
0.7457	kw/hp

Exhibit 5
AEWC & ICAS

Exhibit 5
AEWC & ICAS

Exhibit 5
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Shell Offshore Inc.
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Criteria Pollutant Emission Inventory

Fleet Unit: Oil Spill Response, Kvichak 34-foot No. 1, 2 (two) and 47-foot Work Boats
Fuel: Liquid distillate, #1 or #2

Equipment Type: Internal Combustion Engines - propulsion
Make/Model[1]: Cummins QSB
Aggregate Rating[1]: 2600 hp Emissions are for all Cummins QSB engines

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	0.155	g/hp-hr	24	4,032		0.89	21	1.79	0.112	0.112	0.051
NO_x	4.644	g/hp-hr	24	4,032		26.62	639	53.67	3.354	3.354	1.544
$PM_{2.5}$	0.077	g/hp-hr	24	4,032		0.44	11	0.89	0.056	0.056	0.026
PM_{10}	0.077	g/hp-hr	24	4,032		0.44	11	0.89	0.056	0.056	0.026
SO_2	0.000030	lb/lb fuel	24	4,032		0.03	1	0.06	0.004	0.004	0.002
VOC	0.078	g/hp-hr	24	4,032		0.45	11	0.90	0.056	0.056	0.026
Lead	0.000029	lb/MMBtu	24	4,032		5.28E-04	0.01	1.06E-03	6.65E-05	6.65E-05	3.06E-05

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC From permit application dated 01-18-10, Appendix A page 17 and 01-20-10 email with Attachment from Environ (Kirk to EPA (Natasha Greaves)
$PM_{2.5}$ and PM_{10} emissions assumed to be same as PM emissions
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Equipment Type: Internal Combustion Engines - generators
Aggregate Rating[1]: 33 hp Emissions are for all generator engines

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	0.95	lb/MMBtu	24	4,032		0.22	5	0.44	0.028	0.028	0.013
NO_x	4.410	lb/MMBtu	24	4,032		1.02	24	2.05	0.128	0.128	0.059
$PM_{2.5}$	0.31	lb/MMBtu	24	4,032		0.07	2	0.14	0.009	0.009	0.004
PM_{10}	0.31	lb/MMBtu	24	4,032		0.07	2	0.14	0.009	0.009	0.004
SO_2	0.000030	lb/lb fuel	24	4,032		3.68E-04	1.00E-02	7.43E-04	0	0	0
VOC	0.35	lb/MMBtu	24	4,032		0.08	2	0.16	0.01	0.01	0.005
Lead	0.000029	lb/MMBtu	24	4,032		6.70E-06	1.61E-04	1.35E-05	8.44E-07	8.441E-07	3.88E-07

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC From AP-42, Section 3.3, Table 3.3-1
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
7.076 lbs/gal
133,098 Btu/gal

Footnotes/Assumptions

1 Equipment population, rating and usage based on 3 work boats per permit application dated 01-18-10, Appendix A, pages 17- Each of three identical Kvichak 34-foot boats has two 305 hp propulsion engines and a 12 hp generator The Rozema Skimmer has two 700 hp propulsion engines and a 9 hp generator
2 7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content
3 Sulfur content of fuel: 0.000015 by weight

Exhibit 5
AEWC & ICAS

‹ Winges)

Exhibit 5
AEWC & ICAS

Shell Offshore Inc.
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Criteria Pollutant Emission Inventory

Reference Table 1
Fuel Properties for Distillate Fuel Used on All Emission Units on the Discoverer

Fuel heat value:	133,098 Btu/gal	Keiser, Ronald email to Chris Tengco, 01/26/09, see permit application dated February 23, 2009, Appendix F, page 27.			
Fuel density:	847.9 kg/m^3	SCANRAFF-Vladimir Ignatjuk Certificate of Quality. 09/19/04.			
	7.076 lbs/gal	converted based on	453.59	g/lb	and
			264.17	gal/m^3	

Reference Table 2
Comparison of Controlled Emission Factors for Cementing Units and Logging Winches

Pollutant	Detroit 8V71N Emission Factors cont. (g/hp-hr)	Detroit 3V-71 Emission Factors cont. (g/hp-hr)	John Deere Emission Factors, cont. (g/kW-hr)	John Deere Emission Factors, cont. (g/hp-hr)	Caterpillar C7 Emission Factors, cont. (g/kW-hr)	Caterpillar C7 Emission Factors, uncont. (g/hp-hr)	Maximum Emission Factor	Emission Factor Units
CO	0.299	0.66	0.55	0.41	0.70	0.52	0.66	g/hp-hr
NO_x	9.81	11.72	7.5	5.59	4.0	2.98	11.72	g/hp-hr
$PM_{2.5}$	0.19	0.29	0.09	0.07	0.03	0.02	0.29	g/hp-hr
PM_{10}	0.19	0.29	0.09	0.07	0.03	0.02	0.29	g/hp-hr
VOC	0.148	0.20	0.75	0.56	4.0	2.98	2.98	g/hp-hr

SO_2 emissions not compared as they are based on mass balance

Reference Table 3
Comparison of Emission Factors for Marine Engines

Pollutant	AP-42 Section 3.4 lb/hp-hr	g/kW-hr	IVL g/kW-hr	Lloyd's g/kW-hr	Maximum EF g/kW-hr
CO	5.50E-03	3.35	1.4	1.6	3.35
NO_x[5]	0.056	25.40	18.1	17	25.40
$PM_{2.5}$	0.00056	0.34	1.54		1.54
PM_{10}	0.00058	0.35	1.92	1.5	1.92
SO_2[5]	1.2135E-05	0.01	0	0.798	0.80
VOC	0.000705	0.43	0.6	0.5	0.60

Reference Table 4
Comparison of Emission Factors for Marine Engines and External Combustion

Pollutant	Marine Engine EF g/kW-hr	Marine Engine EF[1] $lb/10^3$ gal	AP_42 Section 1.3 Tables 1 to 3 $lb/10^3$ gal	Maximum EF $lb/10^3$ gal
CO	3.35	104.58	5	104.58
NO_x[5]	25.40	794.01	20.00	794.01
$PM_{2.5}$	1.54	48.14	3.30	48.14
PM_{10}	1.92	60.02	3.30	60.02
SO_2[5]	0.80	24.94	26.98	26.98
VOC	0.60	18.76	0.34	18.76

1 Conversions based on 745.7 watts/hp
453.59 g/lb
Brake specific fuel consumption: 7000 Btu/hp-hr

Exhibit 5
AEWC & ICAS