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-09-01

SHELL GULF OF MEXICO INC.
FRONTIER DISCOVERER DRILLSHIP
CHUKCHI SEA EXPLORATION DRILLING PROGRAM

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Date of Proposed Permit: August 14, 2009

Exhibit 8
AEWC & ICAS

TABLE OF CONTENTS

ABBREVIATIONS AND ACRONYMS

ASTM .... American Society of Testing and Materials
BACT.................................. Best available control technology
CAA………………………..Clean Air Act
CCV .... Closed Crankcase Ventilation
CDPF .... Catalytic Diesel Particulate Filter
CFR..................................... Code of Federal Regulations
CO....................................... Carbon monoxide
EPA..................................... United States Environmental Protection Agency
Discoverer............................ Frontier Discoverer drillship
HAP .... Hazardous Air Pollutants
H_2S...................................... Hydrogen Sulfide
hp .... Horsepower
HPU .... Hydraulic Power Units
IC .... Internal Combustion
kW .... kiloWatts
kW-e .... kiloWatts electric
lbs.. pounds
MLC.................................... Mud line cellars
MMBtu .... million British thermal units
NA .... Not applicable
NESHAP.............................. National Emission Standards for Hazardous Air Pollutants
NOx..................................... Oxides of nitrogen
NSPS................................... New Source Performance Standards
NSR…………………………New Source Review
OCS..................................... Outer continental shelf
OSR..................................... Oil spill response
Part 55 .... 40 CFR Part 55
$PM_{2.5}$ .... Particulate matter with an aerodynamic diameter less than 2.5 microns
PM_{10}.................................... Particulate matter with an aerodynamic diameter less than 10 microns
ppm .... parts per million
ppmv .... parts per million by volume
PSD...................................... Prevention of Significant Deterioration
PTE .... Potential to Emit
Rpm...................................... revolutions per minute
SCAC................................... Separate circuit aftercooled
SER...................................... Significant emission rate
SO_2....................................... Sulfur dioxide
Shell .... Shell Gulf of Mexico Inc.
SSBOP .... Subsea blowout preventer
tpy .... tons per year
VOC..................................... Volatile organic compound
wt%...................................... weight percent

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 (CFR), 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 CFR § 52.21.

Under these programs, Shell Gulf of Mexico Inc. (Shell)[1] has applied for a portable major source permit to authorize mobilization and operation of the Frontier Discoverer drillship (Discoverer) and its associated fleet at various drill sites in the Chukchi Sea outer continental shelf (OCS) off the North Slope of Alaska. EPA has completed its review of the application and supplemental materials and is proposing to issue Permit No. R10OCS/PSD-AK-09-01 to authorize Shell's Chukchi Sea exploratory oil and gas drilling program (exploration drilling program).

40 CFR Part 124, Subparts A and C, contain the procedures that govern the issuance of both OCS and PSD permits. See 40 CFR §§ 55.6(a)(3) and 124.1. Accordingly, EPA has followed the procedures of 40 CFR 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 CFR § 124.7, also serves as a Fact Sheet as provided in 40 CFR § 124.8.

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[1] Although the permit application was initially submitted by Shell Offshore Inc., the applicant has since clarified that Shell Gulf of Mexico Inc. is the only entity with rights to conduct activities under the leases and is responsible for compliance with all regulations and orders for activities on the leases. Shell Gulf of Mexico Inc. has confirmed that it stands by all statements made in the permit application. As a result, EPA is issuing the permit to Shell Gulf of Mexico Inc.

Application Chronology[2]

Date	Document Description
11/12/2008	Modeling Protocol for Chukchi and Beaufort Sea Exploration Drilling Program
12/11/2008	Shell Offshore Inc. – Initial application received by EPA
01/15/2009	Email Regarding the Discoverer Chukchi Source Contribution
01/16/09	EPA letter of incompleteness to Shell
01/26/2009	Email Regarding the Shell Chukchi Icebreaker Characterization
02/23/2009	Shell Offshore Inc. – Replacement Application – Cover Letter
02/23/2009	Shell Offshore Inc. – Replacement Application – Revised Application
02/23/2009	Shell Offshore Inc. – Replacement Application – Appendices A-G
03/12/09	EPA letter of incompleteness to Shell
03/20/2009	Email regarding Chukchi Sea Leases
04/14/2009	Email Regarding the Impact Modeling for Warehouse Emissions – Wainwright or Barrow
04/23/2009	Email Regarding Conference Call on Icebreakers
04/27/2009	Email Regarding Volume Sources
05/05/2009	Email Regarding Updated Emissions Inventory
05/11/2009	Email Regarding Wainwright Audit Reports
05/14/2009	Email regarding Proposed Alternative handling of Ice Management Fleet, Supply Ship, Nanuq
05/18/2009	Shell Offshore Inc. – Response to March 12, 2009 EPA Letter of Incompleteness
05/19/2009	Email Regarding Wainwright March 2009 Summary Report
05/20/2009	Email Regarding Ice Management Vessel
05/29/2009	Shell Offshore Inc. – Updated Response to March 12, 2009 EPA Letter of Incompleteness
06/01/2009	Shell Offshore Inc. – Supplemental Response – Additional Impact Analysis
06/05/2009	BACT Analysis for Volatile Organic Compounds
06/05/2009	Email Regarding Shell Chukchi and Beaufort Sea PSD Applications
06/09/2009	Email Regarding Confirmation of Formal Submittals
06/16/2009	Emails Regarding Information on Non-Criteria Regulated Air Pollutants (2 emails)
06/19/2009	Email Regarding Criteria Emission and Compliance Monitoring
06/23/2009	Email Follow-Up Regarding Anchor Handling and Bow Emissions

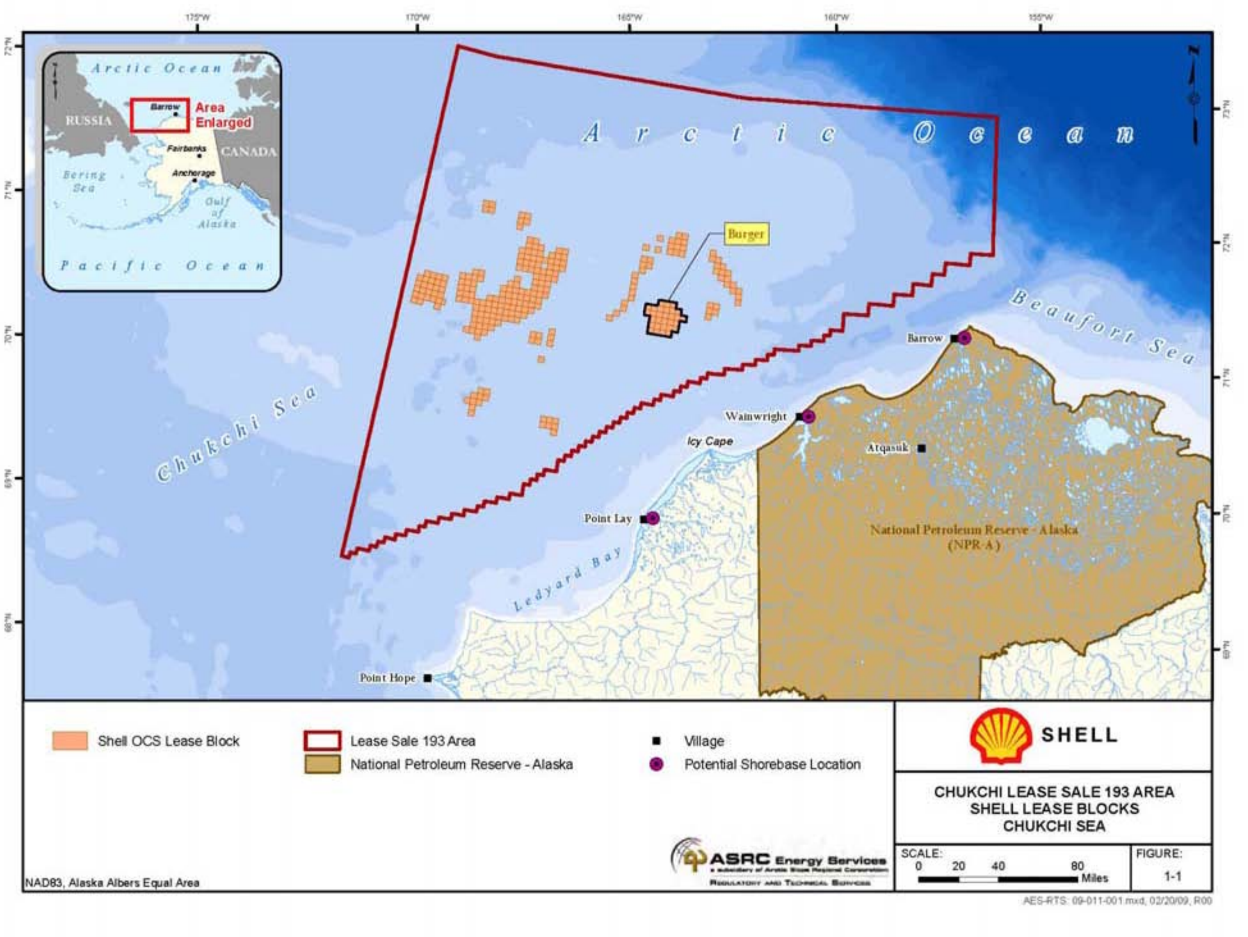
[2] The Administrative Record also contains numerous emails and correspondence between Shell and its consultants and EPA clarifying various aspects of Shell's application.

Date	Document Description
06/23/2009	Email Regarding PM 2.5 Discoverer Bow
06/23/2009	Email Regarding PM 10 Discoverer Bow
06/23/2009	Email Regarding PM 2.5Anchor Handling
06/23/2009	Email Regarding Modeling Files
06/24/2009	Email Regarding Information on Supply Ship
06/26/2009	Email Regarding Discoverer Re-Orientation
06/30/2009	Anchor Setting Emissions
07/06/2009	Email Regarding Associated Emissions
07/06/2009	Email Regarding Information on Title VI Potential to Emit
07/12/2009	Email on Anticipated Compliance Conditions
07/13/2009	Email Regarding Ice Removal – Discoverer Bow
07/15/2009	Emails Regarding Anchor Setting Emissions (2 emails)
07/16/2009	Email Regarding Bow Washing Emissions for PM 2.5 and PM 10
07/16/2009	Email Regarding Wainwright Neat-Term Monitoring Program May 2009 Data Summary
07/17/2009	Email Regarding Bow Washing Emissions for PM 2.5 and PM 10
07/17/2009	Email Regarding Background Concentrations
07/28/2009	Email regarding Wainwright Near Term June 2009 Data Summary
7/31/09	EPA letter of completeness to Shell
08/10/2009	Email Regarding Changes to the Permit Compliance Conditions
08/12/2009	Email regarding the Permittee Name
08/12/2009	Emails Regarding Example Model Runs
08/12/2009	Email Regarding Shell Request for a Modification on the Discoverer Location Restrictions
08/13/2009	Email Regarding the Anchor Handling Restricted Area geometry
8/13/09	Email Regarding Example Model Runs
8/13/09	Email Regarding Example Model Runs

1.2 Project Description

To implement their Chukchi Sea exploration drilling program, Shell proposes to operate the Discoverer drillship and associated fleet in the Chukchi Sea. The application submitted by Shell is for a portable major source permit to allow for operation of the Discoverer and its associated fleet at any of Shell Gulf of Mexico Inc.'s current leases within the Chukchi Sea, all of which are beyond 25 miles from Alaska's seaward boundary. Figure 1-1 shows the location of the current Shell Gulf of Mexico Inc. leases in the Chukchi Sea. This region can be described as lying west of Wainwright (162° west longitude) and north of Point Lay (71° north latitude).

<u>Figure 1-1 – Chukchi Sea Lease Sale Area 193</u>



Under the terms of this proposed permit, the Shell is limited to operating the Discoverer in only the following lease blocks from lease sale 193:

NR02-02:	6819	6820	6821	6822	6868	6869	6870	6871	6872	6918	6919
	6920	6921	6922	6968	6969	6970	6971	6972	7018	7019	7020
	7021	7022	7023	7068	7069	7072					
NR03-01	6105	6106	6155	6156	6161	6162	6211	6212	6261	6363	6364
	6413	6414	6415	6418	6419	6462	6463	6464	6465	6467	6468
	6469	6512	6513	6514	6515	6516	6517	6518	6519	6562	6563
	6564	6565	6567	6568	6569	6612	6613	6614	6615	6616	6617
	6618	6665	6666	6667	6668	6705	6706	6712	6715	6716	6717
	6753	6754	6755	6756	6761	6762	6765	6766	6767	6803	6804
	6805	6810	6811	6812	6813	6814	6815	6816	6817	6853	6854
	6855	6860	6861	6862	6863	6864	6865	6866	6903	6904	6905
	6908	6909	6910	6911	6912	6913	6914	6915	6916	6953	6954
	6955	6956	6957	6958	6959	6960	6961	6962	6963	6964	6965
	7006	7007	7008	7009	7010	7011	7012	7013	7014	7056	7057

	7058	7059	7060	7061	7062	7063	7106	7107	7108	7109	7110
	7119										
NR03-02:	6114	6115	6161	6163	6164	6165	6213	6214	6215	6220	6259
	6261	6263	6264	6265	6270	6271	6321	6322	6359	6360	6371
	6372	6409	6410	6422	6423	6459	6508	6558	6608	6658	6671
	6672	6708	6713	6714	6715	6721	6722	6757	6761	6762	6763
	6764	6765	6766	6771	6807	6811	6812	6813	6814	6815	6816
	6817	6856	6862	6863	6864	6865	6866	6905	6912	6913	6914
	6915	6916	6962	6963	6964	6965					
NR04-01:	6352	6401	6402	6452	6453	6503	6504	6554	6604		
NR03-03:	6007	6008	6009	6010	6017	6018	6020	6056	6057	6058	6059
	6067	6068	6070	6108	6219	6560	6561	6609	6610	6611	6658
	6659	6660	6709	6721	6722	6723	6759	6771	6772	6773	6823

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.

<u>Figure 1-2 – Photograph of the Frontier Discoverer Drillship</u>

Exhibit 8
AEWC & ICAS

Prior to mobilizing to the Chukchi Sea, the drillship is provisioned with sufficient supplies required to conduct the initial drilling operations. Together with the ice management and anchor handler fleet, consisting of an icebreaker and an arctic class anchor handler/ice management vessel, 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 anchor handler/ice management 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.

After drilling and installing casing in the next interval, the SSBOP's are installed in the MLC. At this point the Oil Spill Response (OSR) 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 Wainwright or Barrow, Alaska.

The Discoverer's operations are supported by an associated fleet that consists of a primary icebreaker, secondary icebreaker,[3] supply ship, oil spill response ship and oil spill workboats (such support vessels to be referred to as the "Associated Fleet"). 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 be deployed upwind of the drillship. The primary icebreaker will be

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[3] Also referred to as the artic class anchor handler/ice management vessel.

located further from the Discoverer and cover a wider operating range. The secondary icebreaker will operate closer in and will also serve to deploy and retrieve the Discoverer's anchors.

The Chukchi exploration program will be replenished by a supply ship that is expected to make no more than 8 trips each drilling season from port to the Discoverer. Discoverer operations are also supported by an oil spill response ship, equipped with three workboats 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 to December each year) until the resources under Shell's current leases are adequately defined.

1.3 Public Participation

1.3.1 Opportunity for Public Comment

These proceedings are subject to the requirements of 40 C.F.R. Part 124. As provided in Part 124, EPA is seeking public comment on the proposed Shell OCS/PSD permit for the Chukchi Sea. The public comment period runs from August 20, 2009 through October 5, 2009. All written comments must be postmarked by October 5, 2009. As discussed in Section 5, 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.

Any interested person may submit written comments on the proposed permit during the public comment period. If you believe any condition of this permit is inappropriate, you must 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.

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.

Send comments on the proposed permit to:

Shell Chukchi OCS Air Permit
EPA Region 10
200 6th Ave, Ste. 900, AWT-107
Seattle, Washington 98101
Fax: 206-553-0110
Email: R10ocsairpermits@epa.gov

1.3.2 Public Hearing and Informational Meetings

EPA is holding public hearings and informational meetings on the proposed OCS/PSD permit as follows:

September 23, 2009
North Slope Borough Assembly Room
1689 Okpik Street, Barrow, Alaska
Informational meeting: 3 p.m. – 5 p.m.
Public hearing: 5 p.m. – (until comments finished)

September 25, 2009
Loussac Public Library Assembly Chamber
3600 Denali Street, Anchorage, Alaska
Informational meeting: 10 a.m. – 11 a.m.
Public hearing: 11 a.m. – 2 p.m.

Inupiat translation will be available at the meeting and hearing in Barrow. The public can also participate in the public hearing by telephone at the teleconference centers in Atqasuk, Wainwright, Point Lay, and Point Hope.

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.

1.3.3 Administrative Record

The record for the proposed permit includes the permit application and supporting information from Shell, the statement of basis for the proposed permit, documents cited in the statement of basis, the proposed permit, and supporting materials. The permit application, statement of basis, proposed permit, and permit information sheet are available for public review at the locations listed below. Please call in advance for available viewing times.

Barrow City Office, 2022 Ahkovak Street, Barrow, Alaska, 907-852-4050
Wainwright City Office, 1217 Airport Road, Wainwright, Alaska, 907-763-2815
Atqasuk City Office, 5010 Ekosik Street, Atqasuk, Alaska, 907-633-6811

Kali School Library, 1029 Ugrak Ave, Point Lay, Alaska, 907-833-2312
Point Hope City Office, 530 Natchiq Street, Point Hope, Alaska, 907-368-2537
EPA Alaska Office, Federal Building, 222 West 7th Ave, Anchorage, Alaska, 907-271-5083

The permit application, statement of basis, proposed permit and a permit information sheet are also available on the web at: http://yosemite.epa.gov/R10/airpage.nsf/Permits/chukchiap. The permit record is available at the EPA Region 10 Library, 1200 6th Ave, Seattle, Washington, 206-553-1259. To request a copy of these materials or a copy of the permit record, contact Suzanne Skadowski as described above.

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.

To be added to our mailing list to receive future information about this permit or other OCS permitting in Alaska, please contact Suzanne Skadowski at the contact information listed above.

Exhibit 8
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2. REGULATORY APPLICABILITY

2.1 OCS

The OCS regulations at 40 CFR Part 55 (Part 55) implement Section 328 of the Clean Air Act (CAA) and establish the air pollution control requirements for OCS sources and the procedures for implementation and enforcement of the requirements. 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 CFR § 55.2; see also CAA § 328(a)(4)(C), 42 U.S.C. § 7627.

Section 328 and Part 55 distinguish between OCS sources located within 25 miles of a state’s seaward boundaries and those located beyond 25 miles of a state’s seaward boundaries. CAA § 328(a)(1); 40 CFR §§ 55.3(b) and (c). In this case, Shell is seeking a permit for exploration drilling operations that will be conducted exclusively beyond 25 miles of Alaska’s seaward boundaries.

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 CFR § 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 CFR Part 71. See 40 CFR §§ 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 2.5 below.

The OCS regulations also contain provisions relating to monitoring, reporting, inspections, compliance, and enforcement. See 40 CFR §§ 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.

2.2 PSD

The PSD program, as set forth at 40 CFR § 52.21, and incorporated by reference into 40 CFR § 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.

Under the PSD regulations, a stationary source is "major" if, among other things, it emits or has the potential to emit (PTE) 100 tpy or more of a "regulated NSR pollutant" as defined in 40 CFR § 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 potential to emit 250 tpy or more of a regulated NSR pollutant. 40 CFR § 52.21(b)(1). "Potential to emit" 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 CFR § 52.21(b)(4).

In the case of "potential emissions" from OCS sources, Part 55 defines the term similarly and provides 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 enroute to or from the source when within 25 miles of the

[4] Section 109 of the CAA requires EPA to promulgate regulations establishing national ambient air quality standards (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: sulfur dioixde, particulate matter, nitrogen dioxide, carbon monoxide, ozone, and lead. 40 CFR 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."

> 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 CFR § 55.2. Consequently, in determining the PTE for Shell's Chukchi Sea exploration drilling program, potential emissions from the icebreakers, the supply ship and the OSR fleet were included. As discussed in Section 1, Shell has applied for a portable major source permit authorizing operation of the Discoverer and its Associated Fleet at any of Shell's current leases in Lease Sale Area 193 of the Chukchi Sea. Shell's application calculated the PTE from the project based on emissions from all drilling locations authorized under the permit during any consecutive 12-month period.

Table 2.1 lists the PTE for each regulated NSR pollutant from the project, as well as the significant emission rate (SER) for each regulated NSR pollutant. Appendix A contains detailed emissions calculations used to determine PTE for emissions of carbon monoxide (CO), oxides of nitrogen (NO_x), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), volatile organic compounds (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 and Appendix B. The PTE estimates for the remaining regulated NSR pollutants are set forth in Air Sciences 2009a-c.

Table 2.1 - Potential to Emit for Regulated NSR Pollutants

Pollutant	Potential to Emit, tpy	Significant Emission Rate, tpy
CO	762	100
NO_x	1965	40
PM	260	25
$PM_{2.5}$ (precursors NO_x and SO_2)	184	10 (40 for NO_x or SO_2)
PM_{10}	210	15
SO_2	181	40
VOC	166	40
Lead	0.14	0.6
Ozone (precursors VOC and NO_x)	NA	40 for VOC or NO_X
Fluorides	0	3
Sulfuric acid mist	0	7
Hydrogen sulfide	0	10
Total reduced sulfur	0	10
Reduced sulfur compounds	0	10
Municipal waste combustor organics	3.66×10^{-7}	3.5×10^{-6}
Municipal waste combustor metals	0.125	15
Municipal waste combustor acid gases	4.45	40
Municipal solid waste landfill emissions	NA	50
Title VI, Class I or II substance	< 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 1998a and b)

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 Chukchi exploration drilling program is a major PSD source because emissions of CO, NO_x, and PM exceed the major source applicability threshold of 250 tpy. In addition, emissions of CO, NO_x, PM, $PM_{2.5}$, PM_{10}, SO_2 and VOC exceed the significant emission rate for each such pollutant. Consequently, pursuant to 40 CFR § 52.21(j)(2), Shell is required to apply BACT for each of these pollutants. Section 4 contains a discussion of the BACT analysis for each of these pollutants. Additionally, and consistent with 40 CFR §§ 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] Section 5 and Appendix B contains a discussion of the air quality impact analysis.

2.3 Title V

As specified in 40 CFR § 55.13(f)(2), the requirements of the Title V operating permit program, as set forth at 40 CFR Part 71 (Part 71), apply to OCS sources located beyond 25 miles of States' seaward boundaries. Because the PTE for this project is greater than 100 tons per year for several criteria pollutants, it is a major source under Title V and Part 71 and must apply for an operating permit within 12 months of setting the first anchor at the first drill site on Shell's current leases in the Chukchi Sea as provided in 40 CFR § 71.5(a)(1)(i).

2.4 New Source Performance Standards (NSPS)

As discussed above, applicable NSPS apply to OCS sources. See 40 CFR § 55.13(c). In addition, the PSD regulations require each major stationary source or major modification to meet applicable NSPS. See 40 CFR § 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 CFR Part 60, Subpart IIII, applies to stationary compression-ignition internal combustion (IC) engines, with the earliest applicability date being for units for which construction commenced after July 11, 2005. 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) were constructed prior to July 11, 2005 (Air Sciences 2009d), and therefore are not subject to NSPS IIII. The diesel MLC compressor engines, FD-9 to FD-11, are new Tier 3[6] engines to which NSPS IIII applies.

NSPS Dc, 40 CFR 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 CFR 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 CFR § 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

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[5] See Section 3.1 below for a discussion of PSD increments.

[6] 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.

burns more than 30% 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 CFR § 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 2009).

NSPS Subpart Ka, 40 CFR 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 CFR 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, are subject to NSPS IIII and the incinerator is subject to requirements for maintaining an exemption from NSPS CCCC. As provided in 40 CFR §§ 52.21(j)(1) and 55.13(c), the permittee must meet each applicable standard of performance under 40 CFR Part 60. The applicable provisions of the NSPS have not been included in this proposed OCS/PSD permit, but Condition A.3, as well as 40 CFR §§ 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.

2.5 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 CFR § 55.13(e). In addition, the PSD regulations require each major stationary source or major modification to meet applicable standards under 40 CFR Part 61, which are NEHSAPs. See 40 CFR § 52.21(j)(1).

No source categories on board the Discoverer are currently regulated by NESHAPs promulgated at 40 CFR 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 CFR 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 CFR § 63.2. A major source is generally defined as a source that has a PTE of 10 tons per year or more of any single "hazardous air pollutant" or "HAP" or 25 tons per year or more of all HAP combined. See Section 112(a)(1) and 40 CFR § 63.2. An "area source" is any source that is not a major source. See Section 112(a)(2) and 40 CFR § 63.2.

Shell has estimated emissions of HAP from Shell's exploration drilling program 3.50 tons per year for all HAP combined based on requested limits and other limits assumed under the permit application and supporting materials submitted to EPA. (Shell 2009, Attachment D, Table 2-2, and Attachment E, pp E.1-12 to -13). 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 CFR 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 CFR Part 63, Subparts A and ZZZZ, including the initial notification, if they fall within 40 CFR § 63.6590(b)(3). See also 40 CFR § 63.6590(a)(1)(iii). Engines FD-1 to FD-8 and FD-12 through 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, were constructed after June 12, 2006, and therefore qualify as new engines. As provided in 40 CFR § 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 CFR Part 60, Subpart IIII, for compression-ignition engines. As discussed above in Section 2.4, FD-9 to FD-11 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, which comply with Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII. As discussed above, Condition A.3, as well as 40 CFR §§ 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 OCS/PSD proposed permit. All applicable standards promulgated under Section 112 will be included in the Title V operating permit for Shell.

2.6 Abbreviated References Cited in Section 2.

Air Sciences. 2009a. E-mail from Rodger Steen, Air Sciences, to Pat Nair and Herman Wong, EPA. June 16, 2009.

Air Sciences. 2009b. E-mail from Rodger Steen, Air Sciences, to Pat Nair and Paul Boys, EPA. June 19, 2009.

Air Sciences. 2009c. Technical Memorandum dated June 30, 2009 from Rodger Steen, Air Sciences, to Pat Nair, EPA – transmitted by e-mail on July 6, 2009.

Air Sciences. 2009d. E-mail from Rodger Steen, Air Sciences, to Pat Nair, EPA. July 16, 2009.

EPA. 1998a. Letter from John S. Seitz, EPA, to Gustave Von Bodungen, Louisiana Department of Environmental Quality. February 24, 1998.

EPA. 1998b. Letter from John S. Seitz, EPA, to Kevin Tubbs, American Standard. March 19, 1998.

EPA. 2009. Letter from Nancy Helm, EPA, to Susan Childs, Shell. January 21, 2009.

Shell 2009. Letter from Susan Childs, Shell, to Janis Hastings, EPA, Transmitting Updated Attachments D and E to Shell Application. May 29, 2009.

3. PROJECT EMISSIONS AND PERMIT TERMS AND CONDITIONS

3.1 Overview

Shell intends to implement their Chukchi 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, 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 CFR §§ 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 at the source and while enroute to or from the source when within 25 miles of the source.

The detailed emissions calculations for the Chukchi Sea exploration drilling program are contained in Appendix A and in Air Sciences 2009d-f. 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 and updates).

The emission inventory reflects application of emission limitations representing best available control technology or "BACT." As discussed in Section 4.1, a new major stationary source is required to apply BACT for each pollutant subject to regulation under the Clean Air Act that it would have the potential to emit in significant amounts. 40 CFR § 52.21(j). Based on the emission inventory for the OCS source presented in Table 2-1, the emissions of NO_x, PM, $PM_{2.5}$, PM_{10}, SO_2, VOC and CO 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 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 CFR § 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 CFR § 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 and Appendix B. As can be seen from that analysis, 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, fuel usage monitored by fuel meters, and annual fuel usage limits.

Except for those conditions addressing notification, reporting and testing, the permit conditions contained in Sections A 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. For the purpose of the permit, the Discoverer is an "OCS source" during all times between placement of the first anchor on the seabed and removal of the last anchor from the seabed at a drill site.

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.

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 CFR §§ 55.6(a)(4)(i) and 52.21(r)(1).

Condition A.2 specifies the enforcement authority for violation of OCS and PSD regulations and this permit, as provided in 40 CFR §§ 55.9(a)-(b) and 52.21.

Condition A.3 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 CFR §§ 55.6(a)(4)(iii) and 52.21(r)(3).

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

Condition A.5 contains provisions relating to automatic expiration of PSD permits as provided in 40 CFR § 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 CFR § 124.5(g)(2), such permit expiration is not subject to the procedural requirements of 40 CFR Part 124.

Condition A.6 contains provisions for revision, termination, or revocation and reissuance of the permit. Although 40 CFR Part 124 does not contain such procedures for OCS or PSD permits, see 40 CFR § 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 Clean Air Act. Should EPA decide cause exists to revise, terminate, or revoke and reissue the permit, EPA will follow 40 CFR Part 124. EPA intends to give Shell reasonable notice prior to initiating such action.

Condition A.7 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 Clean Air Act requirements. See 40 CFR §§ 52.12(c), 60.11(g), 61.12(e), and 62 Fed. Reg. 8314 (February 24, 1997).

Condition A.8 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 CFR Part 71 within one year of commencing operation. To facilitate incorporation of the requirements of this permit into the permittee's Title V permit, EPA has used the inspection language in 40 CFR § 71.6(c).

Condition A.9 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 CFR § 71.6(a)(3).

Condition A.10 specifies the EPA address to which information under the permit must be submitted.

Condition A.11 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 CFR § 71.5(d).

Conditions A.12 and A.13 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 CFR §§ 71.6(a)(5) and 71.6(a)(6)(iv).

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.

Condition B.1 requires Shell to notify EPA at least 10 days prior to setting the first anchor from the Discoverer to the seabed at any drill site. This permit condition is designed to implement the requirement of 40 CFR § 52.21(i)(1)(viii) for portable stationary sources. Under this provision, a portable stationary source that has previously received a PSD permit—in this case, the permit proposed in this action—is exempt from the PSD requirements of 40 CFR §§ 52.21 (j) through (r) in the future if the source proposes to relocate the source provided the emissions at the new location would be temporary, emissions from the source will not exceed allowable emissions under the permit, emissions from the source will not impact a Class I area or an area where an applicable increment is known to be violated, and the source provides prior notice to EPA. This proposed permit authorizes operation of the OCS source at multiple temporary locations in the Chukchi Sea. The emissions limits and related monitoring, recordkeeping, and reporting apply at all locations. Overall operation as an OCS source under the permit is limited to 168 days per rolling 12-month period. Condition B.1 implements the remaining requirements of 40 CFR § 52.21(i)(1)(viii) by requiring the permittee to notify EPA of the proposed new location and probable duration of 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.

Condition B.2 limits the duration of Shell's exploration operations in the Chukchi 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 a limit of 168-days of operation as an OCS source. Condition A.13 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. 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.

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

Condition B.4 imposes a BACT limit of 0.0015 percent sulfur by weight on emissions of SO2 from the Discoverer engines. Shell is required to monitor fuel sulfur content by either testing the fuel being used or obtaining supplier certifications from the supplier.

Condition B.5 limits the fuel sulfur content of fuel used in the Associated Fleet to a sulfur content of 0.19 percent by weight. Again, Shell is required to monitor fuel sulfur content by either testing the fuel being used or obtaining supplier certifications from the supplier.

Condition B.6 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 – 11), be equipped with a closed crankcase ventilation (CCV) system. The MLC Compressor Engines have built-in crankcase emission controls.

Condition B.7 contains general testing requirements related to how the stack tests must be conducted. Importantly, the permit condition requires Shell to provide adequate advance notice and to conduct the test in or on the waters of the United States of America so that EPA personnel have an opportunity to observe the tests. It also contains procedures for approval of an alternative to or a deviation from a reference test method.

Condition B.8 prohibits Shell from flow testing wells, flaring gas, or storing liquid hydrocarbons recovered during well testing. 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.8 prohibits them.

Condition B.9 requires Shell to calculate monthly emissions of pollutants of CO, NO_x, $PM_{2.5}$, PM_{10}, SO_2 and VOC. In addition, Condition B.10 requires a monthly calculation of rolling-12-month emissions of each of these pollutants for the prior 12-month period. Condition B.11 requires Shell to notify EPA if any of the emission or throughput limits in the permit are exceeded.

All of the emissions estimates are based on the equipment and control equipment being operated using good practices. Consequently, Condition B.12 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 CFR §§ 60.11(e) and 63.6(e).

3.4 Frontier Discoverer Drillship

Section 3.4 through 3.7 describes 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 for the definition of OCS source). 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
FD-1 – 6	Generator Engines	Caterpillar D399 SCAC 1200 rpm	1,325 hp
FD-7[a]	Propulsion Engine	Mitsubishi 6UEC65	7,200 hp
FD-8	Emergency Generator	Caterpillar 3304	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	Detroit 4-71N	128 hp
FD-20	Logging Winch Engine	John Deere 4024TF	36 kW
FD-21 - 22	Heat Boilers	Clayton 200	7.97 MMBtu/hr
FD-23	Incinerator	TeamTec GS500C	276 lb/hr
FD-24 -30	Fuel Tanks	NA	Various
FD-31	Supply Ship Generator Engine(s)	Generic	584 hp
FD-32	Drilling Mud System	NA	NA
FD-33	Shallow Gas Diverter System	NA	NA

[a] The propulsion engine is not employed when the Discoverer is attached to the seafloor. The propulsion engines are employed while the Discoverer is in transit. While in transit, the Discoverer is not an OCS source.

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% sulfur by weight). This fuel must also be used in the Discoverer incinerator burner.

3.4.1 Generator Engines (FD-1 through 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% 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% 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%. 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% 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.

Condition 5 limits the quantity of fuel that can be combusted in the engines 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, $PM_{2.5,}$ PM10, VOC and visible emissions and to monitor certain parameters in addition to determining the efficiency for each engine. Condition C.7 requires Shell to monitor various operational parameters, including fuel through the use of totalizing, nonresettable diesel fuel flow meters on each engine. In addition to monitoring fuel usage and power output, Shell is required to monitor and record parameters related to good operation of the SCR. Condition C.7.7 requires Shell to monitor and record hourly NO_x emissions.

3.4.2 Propulsion Engine (FD-7)

The Discoverer propulsion engine will be shut down prior to placement of the first anchor and turned back on only after removal of the final anchor. Consequently, this engine will have no emissions during the time the Discoverer drillship is an OCS source.

Based on Shell's application and EPA review, the permit will feature 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, and Condition D.2 requires Shell to report to EPA any use of this engine while the Discoverer is an OCS source.

3.4.3 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 20 minutes at loads up to capacity.

In estimating emissions from this generator, EPA relied upon Caterpillar emissions data from an EPA Health Assessment Document (EPA 2002). 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 20 minutes during any single hour, 20 minutes during any single day and eight hours during any rolling 12-month period. In addition, 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 MLC Compressor Engines (FD-9, 10 and 11)

The 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 CFR § 89.112).[7] 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 limit on PM under the Tier 3 standards. This emission rate was assumed to be representative of PM_{10} and $PM_{2.5}$ emission rates, a conservative assumption.

Condition F.1 contains the BACT emission limits for these engines. Condition F.2 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.4. The annual NO_x limit and fuel limit each apply to all three engines in aggregate. In contrast, Condition F.3 imposes emissions limits for $PM_{2.5}$ and PM_{10} on a per-unit base. To monitor fuel usage, Condition F.6 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.5 requires Shell to stack test one engine each of the first three drilling seasons for CO, NO_x, $PM_{2.5,}$ PM10, VOC and visible emissions at three different loads.

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[7] 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 CFR Part 60, Subpart IIII, is the most stringent of the 3 tiers.

3.4.5 Hydraulic Power Units (FD-12 and 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 (EPA 2002) for engine-specific data. 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 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 (CleanAIR 2009) that with the correct filter on each engine, and with adequate regeneration, the filters are capable of 85% reduction in PM emissions, 90% reduction in CO emissions, and 90% reduction in VOC emissions. CleanAIR Systems has also indicated (CleanAIR 2006) that the exhaust temperature will need to be above 300 degrees Celsius (^{o}C), or 572 degrees Fahrenheit (^{o}F), for at least 30% of the engine operating time for proper filter regeneration using ultra low sulfur fuel (i.e. 0.0015 percent sulfur by weight).

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 ^{o}C for at least 30% 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.8 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.7 requires Shell to stack test one engine each of the first two drilling seasons for CO, NO_x, $PM_{2.5}$, PM_{10}, VOC and visible emissions at three different loads.

3.4.6 Deck Cranes (FD-14 and 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, carbon monoxide, and volatile organics.

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 - 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 are all equipped with CDPFs. 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 Health Assessment Document (EPA 2002) for engine-specific data. 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 and Detroit 4-71 engine (FD-19), 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 fifth engine is a Tier 2 engine, EPA used the corresponding limits in 40 CFR Part 89 to estimate the PTE from this engine.

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 Heaters/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 have 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 Condition 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) 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.6, K.3 and K.4 respectively. In addition to these conditions, the permit also requires stack testing (Condition K.7) and monitoring, recordkeeping and reporting (Condition K.8)

3.4.10 Diesel Fuel Tanks

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 3-23 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 23 lbs of VOC per year (Air Sciences 2009b). 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 2 to 4 weeks, for a maximum of 8 re-provisionings.

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. 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.

The supply ship requirements are contained in Conditions L.1 through L.5. 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.

3.4.12 Mud Drilling System (FD-32)

The wells Shell proposes to drill in the Chukchi 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 136 lbs of VOC (Air Sciences 2009c). Because of the low level of emissions, the proposed permit contains no conditions regarding this emission unit.

3.4.13 Shallow Gas Diverter System (FC-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. The Minerals Management Service (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.

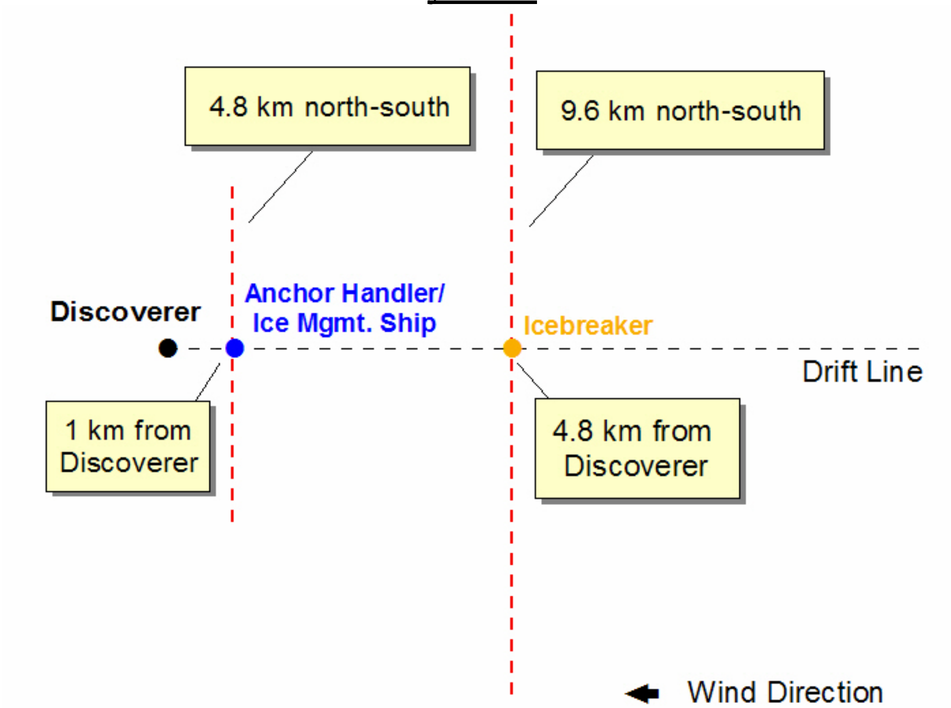
3.5 Ice Management and Anchor Handling Fleet

Shell’s ice management and anchor handling fleet is expected to consist of two leased ships: an icebreaker and an anchor handler/ice management ship. The purpose of this fleet will be 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 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



In the remainder of this Statement of Basis and in the permit, the primary icebreaker will be referred to as Icebreaker #1, and the secondary ice management vessel, which has anchor handling role, will be referred to as Icebreaker #2.

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 km) to either side of the drift line and Icebreaker #2 will be moving laterally 1.5 miles (2.4 km) 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 Icebreakers #1 and #2 from year to year. Consequently, the vessels used as Icebreakers #1 and #2 are likely to change from year to year. In order to accommodate this uncertainty, Shell has requested that the permit allow for a generic ice management fleet. 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 two vessels – the Vladimir Ignatjuk and the Kapitan Dranitsyn. 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. Shell has dropped the Kapitan Dranitsyn from consideration for this project.

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 both of the icebreakers that cannot be exceeded for any vessel. Table 3-3 and 3-4 show the maximum aggregate ratings for each category of equipment for Icebreakers #1 and #2, respectively.

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

Description	Make and Model	Maximum Aggregate Rating
Aggregate of Propulsion Engines and Generator Engines	Various	31,200 hp
Generator Engine(s)	Various	2,800 hp
Heat Boiler(s)	Various	10 MMBtu/hr
Incinerator	Various	154 lbs/hr

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

Description	Make and Model	Maximum Aggregate Rating
Aggregate of Propulsion Engines and Generator Engines	Various	31,200 hp
Generator Engine(s)	Various	2,800 hp
Heat Boiler(s)	Various	10 MMBtu/hr
Incinerator	Various	154 lbs/hr

In addition, Shell has requested limits on $PM_{2.5}$ of 42.2 lbs/hr and on PM_{10} of 48.0 lbs/hr (Air Sciences 2009e), and the permit imposes these restrictions. The 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 N.1 and O.1 contain these equipment capacity and emission limits for the two icebreakers.

Marine propulsion engines 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 (Corbett 2004) compares emission factors from Lloyds with more recent emissions data from the Swedish Environmental Research Institute. 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. Shell also proposed to use these emission factors for the boilers on board the icebreakers. After confirming that these emission factors were in fact more conservative than AP-42 for boilers (Reference Table 4 in Appendix A), EPA also used these emission factors for the icebreaker boilers. In calculating emissions from the emission sources on board the icebreakers, all sources, except the propulsion engines, were assumed to operate at 100% of rated capacity. The propulsion engines were represented at operating at no more than 80% of rated capacity. Consequently, these restrictions are imposed in Conditions N.2 and O.2.

Based on the emissions calculations and resultant modeling, Shell has determined a maximum usage for Icebreaker #2. The emission limits and fuel usage associated with this scenario are contained in Conditions O.3, O.4 and O.5. The fuel limits in Condition O.5 will also serve to limit emissions of the other pollutants, such as CO.

Shell has also proposed a scenario where their need for Icebreaker #2 is less than reflected under conditions O.3, O.4 and O.5. Under these circumstances, they would need to operate Icebreaker #1 at a higher level than if Icebreaker #2 was operated at the maximum allowable levels. This request can be accommodated by having permit conditions that restrict emissions and fuel usage of Icebreakers #1 and 2 in aggregate, as reflected in Conditions N.3, N.4 and N.5.

Based on information currently available, the permit requires Shell to monitor daily fuel usage using fuel flow meters.

Because wind is the mechanism for movement of ice in the arctic, it is important that the Discoverer's bow be facing into the wind (+/- 15 degrees) so that any oncoming ice will contact the Discoverer only on the bow, which is the strongest part of the ship's hull. For this reason, a turret, a large circular ring to which the eight anchor wires are attached, has been installed in the hull of the Discoverer. Although the turret maintains a fixed position over the well, the hull of the Discoverer is free to rotate within this anchor ring and around the turret to orient the bow into the wind. The wind and ice direction is constantly monitored and adjustments made to orient the ship's bow into the wind. This rotation is performed by hydraulic jacks that are electrically powered by the main generators, which are already included in the emission inventory. The propulsion engine is not used to rotate the ship. As a result of these adjustments in orientation angle, the ship is always expected to be within 15 degrees of the wind direction and the time period taken to realign the ship with respect to the wind will be less than an hour, so that periods when the ship is at an angle with respect to the wind will be of short duration.

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. Consequently, the permit contains Conditions N.7 and O.9 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 N.6 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 O.6 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 O.7) and bow washing (Condition O.8). The air quality impact analysis was based on these operating scenarios and therefore the permit contains emission limits to impose these restrictions.

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 N.9 and O.11. Conditions N.10 and O.12 require Shell to conduct monitoring, recordkeeping and reporting to assure compliance with the substantive conditions of Sections N and O of the permit.

3.5.1 Anchor Setting and Retrieval

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. Placement involves backing the handler 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 process consumes no more than 18 hours. Anchor handler propulsion power during these 18 hours is either low or at idle since it is precision work setting anchors, spooling-out lines, and tensioning lines. Since much of this activity takes place while the Discoverer is an OCS source, the anchor management emissions are already included in the fuel use for Icebreaker #2.

Retrieval of the Discoverer anchors involves Icebreaker #2 moving to the location of an anchor and attaching 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. As with the anchor placement process, retrieval of each anchor takes about 30 minutes and the entire process lasts no more than 18 hours. And, as with the anchor placement, this routine is performed at low propulsion power or at idle since it is precision work. The emissions from Icebreaker #2 during anchor retrieval are included in those allowed for Icebreaker #2 in Conditions O.3 and O.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).

3.6 Supply Ship

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. Section 3.4.11 addressed operations and emissions while the supply ship is attached to the Discoverer. This section addresses operations of the supply ship 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

Description	Make and Model	Maximum Aggregate Rating[a]
Propulsion[a] 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% of rated capacity, and both generators operating at full load. Condition P.1 prohibits operation of these engines at loads above 80%, and Condition P.3.1 requires Shell to confirm operations of these engines.

3.7 Oil Spill Response (OSR) Ships

The OSR fleet in the Chukchi is expected to consist of one offshore management ship, the Nanuq, and three 34-foot work boats, the Kvichak No. 1, No. 2 and No. 3. Two of the 34-foot work boats will be used to tow containment booms while the third will act as a backup, for crew changes and re-fueling. The Nanuq 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 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 Nanuq. The Nanuq will have skimmers deployed and be simulating the recovery of oil downstream of the open apex. During this exercise, the small craft as well as the Nanuq will be moving at approximately 0.5 nautical miles per hour.

Table 3-6 presents the emission units on board the Nanuq and each of the Kvichak work boats.

Table 3-6 – Oil Spill Response Fleet

ID	Description	Make and Model	Rating[a]
Oil Spill Response Main Ship - Nanuq			
N-1 - 2	Propulsion Engines	Caterpillar 3608	2,710 hp
N-3 – 4	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 Work Boat - Kvichak 34-foot No. 3			
K-7 - 8	Propulsion Engines	Cummins QSB	300 hp
K-9	Generator Engines	Various	12 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 three Kvichak work boats is equipped with two Cummins QSB engines for propulsion power and a small 12 hp generator engine. Emissions for the former were based on manufacturer's data, while generator engine emissions were determined using AP-42.

The main ambient air impacts from this fleet are annual NO_x. Accordingly, Condition Q.1 imposes an annual NO_x emission limit that results from fuel usage limits requested by Shell. These fuel limits are contained in Condition Q.2. 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 Q.3, Q.4 and Q.5. 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 Q.6 requires Shell to stack test the propulsion engines and the generator engines for emissions of NO_x. Condition Q.7 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 Q of the permit.

3.8 Associated Growth

The indirect activities associated with the Discoverer exploration activities are likely to include support facilities in Wainwright 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 (Air Sciences 2009a). EPA has determined that permit conditions are not necessary to address these types of activities.

3.9 Abbreviated References Cited in Section 3.

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4.1 BACT Applicability and Introduction

Pursuant to 40 CFR § 52.21(j), a new stationary source shall apply BACT for each pollutant subject to regulation under the Clean Air Act that it would have the potential to emit in significant amounts. Based on the emission inventory for the project presented in Table 2-1, NO_x, PM, $PM_{2.5}$, PM_{10}, SO_2, 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, VOC and CO while the drillship is operating as an OCS source.

BACT is defined in 40 CFR §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 CFR 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 Clean Air Act contains a similar BACT definition, although the 1990 Clean Air Act amendments added "clean fuels" after "fuel cleaning or treatment" in the above definition. 42 USC § 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.

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 – 6) that are identical, so the BACT analysis was performed for the group of six engines. Likewise, there are three identical diesel engine driven compressors and a number of smaller diesel engines [<500 horsepower (hp)] which are similar so that the BACT analysis can be performed for each identical or similar group of emission units. EPA agrees that grouping of identical or similar emission units 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 permit application.

Throughout the BACT section PM, $PM_{2.5}$ and PM_{10} 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 available control technologies are similar for all three particulate matter size categories. 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 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 4-4 of the permit application (Shell 2009). 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 is 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 or small boilers. 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

EPA believes that post-combustion control technologies are not feasible for the relatively small emission units on the Discoverer for technical reasons. The fact that no post-combustion controls were found in the RBLC search for diesel IC engines, small boilers, and small incinerators indicates that they have not been found to be technically feasible or cost effective for small emission units in past determinations. 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 ultra-low sulfur diesel fuel (discussed below) results in very low SO_2 emission rates (Table 3-1 shows less than one ton per year of SO_2 for the sum of all emission units on the 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 ultra-low sulfur diesel 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 ultra-low sulfur diesel 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. Ultra-low sulfur diesel fuel is required by other EPA regulations for both on-road diesel vehicles and for non-road diesel engines. Therefore, ultra-low sulfur diesel fuel is available although it may have to be shipped from Canada or the lower 48 states. Not only does ultra-low sulfur diesel 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 PM_{10}, VOC and CO control (discussed in the sections below).

Use of ≤15 ppm ultra-low sulfur diesel for the emission units on the Discoverer provides a greater than 97% reduction in SO_2 emissions compared to low sulfur diesel (≤500 ppm). As mentioned above, using ultra low sulfur diesel fuel, the total annual emissions of SO_2 from all the emission units on the Discoverer are less than one ton per year.

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

Since use of ultra-low sulfur diesel fuel is the most effective control option, EPA is proposing that BACT for SO_2 is the use of ultra-low sulfur diesel 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 4.7

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, ultra low sulfur diesel fuel will be used in all combustion sources on the Discoverer. The processes used by the petroleum refining industry to produce ultra-low sulfur diesel fuel, such as hydrotreating and hydrocracking, remove nitrogen as well as sulfur. Since ultra-low sulfur diesel 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.

Some of the combustion modification technologies for NOx 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% to 50% from baseline emissions depending on the specific technology or combination of technologies (Shell 2009, EPA 2007, EPA 1996, MassDEP 2008).

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 1998). 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 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% 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 2002, WRAP 2005).

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 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 CFR § 52.21(b)(12)(definition of BACT).

4.3.1 NO_x BACT for the Generator Diesel IC Engines

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 through 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% 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 also 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 through FD-6) are ranked by control effectiveness as follows:

1. SCR – 90% control
2. ITR, AC, and/or HIP – 10% to 50% control
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 that SCR represents BACT for the generator diesel IC engines because it offers the highest NO_x emissions reduction of ≥90%. 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 (Permit Application, Appendix F, Footnote 1, page 6), D.E.C. Marine has installed SCR control systems on more than 70 vessels since 1991. The SCR system D.E.C. Marine described in their technical content and offer (Permit Application, Appendix F, page 195 – 209) is capable of reducing NO_x emissions to as low as 0.1 g/kW-hr; 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 below, 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.

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 2007). Testing was performed by TRC Environmental Corporation on May 18 and 19, 2007 for three engine load conditions (100%, 75% and 50%). 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% 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%. 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 CFR § 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 CFR § 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.

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 tons per year as shown in Table 3-1. The maximum total NO_x emissions from all six generator engines would be 9.30 tons per year.

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 2009a). In an email to EPA dated April 20, 2009, Shell's environmental consultant provided a response from D.E.C. Marine (Air Sciences 2009). 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 (Permit Application Appendix F, Footnote 3, page 8). 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.

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 representative of 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 4.7.

4.3.2 NO_x BACT for the Compressor Diesel IC Engines

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 through FD-11 – 540 hp Caterpillar C-15 engines) are ITR, AC, HIP, LND, Tier 2 or Tier 3 controls, WI, EGR, 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.

The compressor diesel IC engines are portable due to critically limited deck space on the Discoverer. The compressors are moved back and forth from storage to the operating locations, as needed. None of the BACT databases reviewed indicated SCR to be BACT for portable diesel engines and Shell did not identify in its application any situation where SCR control technology has been previously installed on deck utility engines of this small size on exploration vessels. Configuring an SCR system along with its reagent supply to be portable adds significant cost and complexity. Additionally, Shell concluded and EPA agrees that the SCR units could only be installed in a horizontal configuration (they have a footprint approximately double that of the air compressors), which would consume limited and valuable deck space and seriously impact the safety of necessary nearby deck operations. For these reasons, EPA believes that SCR is not technically feasible for portable deck engines and has excluded it from further consideration in the BACT analysis for these compressor diesel IC engines.

Step 3 – Rank the remaining technologies by control effectiveness

The technically feasible control technologies for compressor diesel IC engines (FD-9 through 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

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 Winch – 128 hp Detroit 4-71N
6. FD-20, Logging Winch – 48 hp John Deere 4024TF

The available control technologies for engines under 500 hp are ITR, AC, LND, WI, and good combustion practices. LND, EGR, and WI are considered technically infeasible. LND is intrinsic to the original engine design and is not part of the design for these engines. EGR is not available for these older model engines. 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.

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. In addition, the HPUs, cranes and logging winches are portable in the sense that the units move during use. Portable commercial retrofit SCR systems, which include urea tanks, are not available, so this control option is considered technically infeasible as a retrofit for these portable units. The cementing units are stationary on the vessel deck; however, Shell stated in the permit application that it is unaware of any instance where SCR technology has been installed on deck utility engines under 500 hp on exploration vessels. In addition, SCR controls on the Discoverer could only be installed in a horizontal configuration. Because the SCR units have a footprint approximately double that of the cementing engines, SCR would consume too much deck space and would seriously affect the safety of necessary nearby deck operations. For these reasons, EPA believes SCR is technically infeasible for implementation on the Discoverer.

ITR and AC are considered technically feasible for these engines.

Step 3 – Rank the remaining technologies by control effectiveness

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

1. ITR and AC – 10 to 50 percent control
2. ITR – up to 40 percent control
3. AC – approximately 10 percent control
4. Good combustion practice

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

Although ITR and AC could be employed to reduce NO_x emissions, they are detrimental to the performance of a catalytic diesel particulate filter (CDPF) because of the increased loading of PM_{10}, CO and VOC emissions. Since CDPF control technology is proposed for control of other pollutants (PM_{10}, VOC and CO) as discussed in subsequent sections, the increased emissions of PM_{10}, CO and VOC caused by the use of ITR and AC represent a negative environmental impact that disqualify these technologies from consideration as BACT for NO_x in this case. The remaining technically feasible control option is the use of good combustion practice. Good combustion practice for NOx 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 the smaller diesel IC engines 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 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 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 section 3.

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

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 FD-19, Logging Winch Engine	15.717
FD-20, Logging Winch Engine	7.50

4.3.4 NO_x BACT for the Diesel-Fired Boilers

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 Table 3-1 the total estimated emissions of NO_x from the two boilers are 6.46 tons per year.

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 2009, Appendix F, Footnote 37, page 101), and are not available for the diesel fired boilers on the Discoverer. The Clayton literature 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 (Permit Application, Appendix F, Footnote 38, page 104). 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 NOx 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 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 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.

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 section 3.

4.3.5 NO_x BACT for the Incinerator

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 1525 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 (Permit Application, Appendix F, Footnote 39, pages 105 to 112). Since the heat content and the batch size charged to the incinerator will be quite variable, design of an SNCR control system would be difficult. 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 NOx 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 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.

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 section 3.

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) 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 4-5 of the Shell permit application.

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 2009b), and with the control technologies discussed in the Western Regional Air Partnership "Offroad Diesel Retrofit Guidance Document" (WRAP 2005) and the Massachusetts Department of Environmental Protection "Diesel Engine Retrofits in the Construction Industry: A How To Guide" (MassDEP 2008).

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 (Shell 2009, Appendix F, Footnote 51, page 179). 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 through 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 CFR § 52.21(b)(12)(definition of BACT). EPA has promulgated exhaust emission standards for non-road 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 CFR § 89.112 (and several other sections). 40 CFR § 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 through FD-11), the applicable PM emission standard is 0.2 grams per kilowatt hour (g/kW-hr). 40 CFR § 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.

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

4.4.1 PM BACT for the Generator Diesel IC Engines

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 (Permit Application, Appendix F, Footnote 41, page 113). 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% 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.[8]

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% 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

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[8] 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 (see Appendix C of the permit application for the detailed cost calculations).

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 2009, Appendix F, Footnote 47, pages 151 to 166 of the permit application.

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 CFR § 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.

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 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

Because the compressor diesel IC engines are new and meet the EPA Tier 3 emission standards, steps 2 -5 of the BACT process are combined in this discussion. According to the literature describing the Caterpillar C-15 engines (Shell 2009, Appendix F, footnote 36, pages 94 to 99), part of the control technology used on the C-15 engine includes clean gas induction which consists of a DPF and EGR. 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. Although it could be possible to add a CDPF or an OxyCat system in series with the integral controls on the C-15 engines, the relatively low levels of PM emissions from these engines (Table 3-1 shows 0.27 tons per year for PM emissions from the group of the three compressor engines) would result in a high cost effectiveness value. Using the same cost effectiveness estimation technique shown in Appendix C of the permit application (Shell 2009), EPA estimated that the cost effectiveness value for a CDPF on the compressor engines would exceed $100,000 per ton of PM removed, a cost effectiveness value which EPA considers to be unreasonably high. Therefore, EPA proposes that BACT for PM for the compressor diesel IC engines is that the engines meet the Tier 3 engine PM standard of 0.20 g/kW-hr.

In order to detect a significant degradation in the performance of the particulate controls inherent to the compressor engines, EPA is 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 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

<u>Step 2 – Eliminate technically infeasible control options</u>

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. Because they are not part of the design of the Discoverer's smaller diesel IC engines, these control technologies are not technically feasible in this application. LSF, OxyCat, DPF, and CDPF are all considered technically feasible for the smaller diesel IC engines.

<u>Step 3 – Rank the remaining technologies by control effectiveness</u>

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

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.

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

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.

<u>Step 5 – Select PM BACT for the Smaller Diesel Engines</u>

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	0.253
FD-18 Cementing Unit and FD-19, Logging Winch Engines	0.386
FD-20, Logging Winch Engine	0.090

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 installation of CCV for all smaller diesel IC engines except for the MLC Compressor engines (FD 9 through FD-11) 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 particulate 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

Step 2 – Eliminate technically infeasible control options

No PM controls were found in the RBLC or CA-BACT search for small boilers. Although it may be theoretically possible to design an ESP or a fabric filter for the small boilers on the Discoverer, 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. As shown in Table 3-1, the PM emissions for each boiler are 0.38 tons per year. The fact that ultra-low sulfur fuel will be combusted 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 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 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 section 3.

In order to detect a major operating problem with the boilers, EPA is proposing a visible emissions (opacity) limit in addition to the particulate emission 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

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. An ESP is considered technically infeasible for this very small incinerator and ESPs are typically designed for much larger emission units. 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 2009, Appendix F, Footnote 39, pages 105 to 112). Shell also stated in the permit application that they not aware of any control technology installations on this or similar-sized incinerators. Shell proposed that good combustion practices represent BACT for the incinerator.

<u>Step 3 – Rank the remaining technologies by control effectiveness</u>

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

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

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

<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 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.

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 4-7 of the permit application. Crankcase ventilation gases from the diesel engines contain some VOC. CCV eliminates emissions from crankcase blow-by and is integral to the diesel IC engines that meet the Tier 3 emission standards (MLC compressor engines).

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 2009, Appendix F, Footnote 1, pages 6 & 7). 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 90% for both pollutants (CleanAIR 2009).

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than the applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. 40 CFR § 52.21(b)(12)(definition of BACT). As discussed above in section 4.4, EPA has promulgated exhaust emission standards for non-road 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 CFR § 89.112 (and several other sections). 40 CFR § 60.4201(a). For diesel IC engines manufactured to meet the Tier 3 emission standards such as the three 540 hp MLC compressor engines (FD-9 through FD-11), the applicable CO emission standard is 3.5 grams per kilowatt hour (g/kW-hr) 40 CFR § 89.112(a) Table 1. The 540 hp MLC compressor engines are the only diesel IC engines on the Discoverer that are subject to the Tier 3 emission standards.

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. 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

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 2009, Appendix F, Footnote 41, page 113). 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% 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.[9]

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[9] 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 (see Appendix C of the permit application for the detailed cost calculations). 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.

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.

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% for CO and 70% for VOC. The D.E.C. Marine proposed 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 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 through the combustion chamber.

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

EPA is proposing 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 IC Diesel Engines

Because the compressor diesel IC engines are new and meet the EPA Tier 3 emission standards, steps 2 -5 of the BACT process are combined in this discussion. The Tier 3 standard is 3.5 g/kW-hr for CO. Although it could be possible to add a CDPF or an OxyCat system in series with the integral controls on the C-15 engines, the relatively low levels of CO and VOC emissions from these engines (Table 3-1 shows 4.7 tons per year for CO emissions and 5.37 tons per year for VOC emissions for the total of the three compressor engines) do not justify consideration of another control technology in series with the controls already built into the new compressor diesel engines. Therefore, EPA proposes that BACT for CO and VOC for the compressor diesel engines is 3.5 g/kW-hr based on the Tier 3 CO engine standard. The Tier 3 engine standards do not include a separate emission limit for VOC; however, the Tier 3 emission limit for NO_x includes NMHC of which VOC is a subset. As described in Section 4.3.2, the Tier 3 emission limit is 4.0 g/kW-hr for NO_x + NMHC. EPA therefore proposes that the technology necessary to control CO also represents BACT for VOC emissions and proposes the NOx emission limit as representative of BACT for VOC from the compressor IC diesel engines.

4.5.3 CO and VOC BACT for the Smaller Diesel IC Engines

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% control for CO and VOC
2. OxyCat – 80% control for CO and 70% 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 proposes to use CDPF, the top control option, for all of the smaller diesel IC 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% 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	0.20	0.40
FD-14 & 15, Deck Crane Engines	0.0640	0.220
FD-16 & 17, Cementing Unit Engines	0.20	0.40
FD-18 Cementing Unit and FD-19, Logging Winch Engines	0.270	0.880
FD-20, Logging Winch 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 through the combustion chamber.

4.5.4 CO and VOC BACT for the Diesel-Fired Boilers and the Incinerator

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 Table 3-1, the CO and VOC emissions for each boiler are 1.25 tons per year and 0.02 tons per year respectively. Similarly, the CO and VOC emissions for the incinerator are 1.99 tons per year and 0.19 tons per year 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 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 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 section 3. The emission limits for the incinerator are identical to the emission factors for the incinerator from the emission inventory in section 3.

Table 4-4 - CO and VOC Emission Limits for the Boilers and the 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 Supply Vessel at Discoverer

Aside from the supply vessel, the Associated Fleet will not be physically attached to the Discover and therefore will not be part of the OCS source and subject to the BACT requirement. 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 tied alongside 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 tied to the Discoverer (and thus considered part of the "OCS source") would be 96 hours for the drilling season. Since the supply vessel will be a leased vessel, it may only serve the Discoverer for one season. The estimated emissions from the supply vessel while tied to the Discoverer based on the maximum time of 96 hours are shown in Table 3-1. The largest value is 0.43 tons per year for NO_x. The estimated emissions in units of tons per year for all other pollutants are smaller: 0.09 for CO; 0.03 for PM; 0.03 for VOC; and 0.02 for SO_2. Because of the very small emission reduction potential and the short time period over which any control technology would have to amortized, EPA believes that installation of any additional control technology on the supply vessels would not be cost effective. Thus, BACT for the supply vessel is no additional controls.

4.7 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 ultra-low sulfur diesel fuel (≤0.0015% by weight). A representative fuel sample for sulfur analysis must be collected by one of the methods identified in 40 CFR § 80.330(b). Any test method for determining the sulfur content of diesel fuel must satisfy the EPA approval process contained in 40 CFR § 80.585(a) and the precision and accuracy requirements of 40 CFR § 80.584. As an alternative, the sulfur content of the diesel fuel may be determined using ASTM D 5453-09. The permit will specify 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 with respect to $PM_{2.5}$, 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 Fed. Reg. 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 to 56 Fed. Reg. 12970 (March 25, 2009), at which time $PM_{2.5}$ emissions from the incinerator will be measured using EPA Methods 201/201A and 202.

For opacity standards, EPA is proposing EPA Method 9 (40 CFR 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 CFR Part 60, Appendix A, in 40 CFR Part 51, Appendix M or on the EPA Emission Measurement Center webpage http://www.epa.gov/ttn/emc/. Permit Condition B.7.11contains procedures for Shell requesting and EPA approving alternatives to or deviations from the referenced test methods.

4.8 Abbreviated References Cited in Section 4.

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CTM-027. Conditional Test Method 027, "Procedure for Collection and Analysis of Ammonia in Stationary Sources," http://www.epa.gov/ttn/emc/ctm.html

CTM-038. Conditional Test Method 038, "Measurement of Ammonia Emissions from Highway, Nonroad, and Stationary Use Diesel Engines by Extractive Fourier Transform Infrared (FTIR) Spectroscopy," http://www.epa.gov/ttn/emc/ctm.html

OTM 27. Other Test Method 27, "Determination of PM_{10} and PM_{25} Emissions from Stationary Sources (Constant Sampling Rate Procedure)," http://www.epa.gov/ttn/emc/prelim.html

OTM 28. Other Test Method 28, “Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources,” http://www.epa.gov/ttn/emc/prelim.html

5. SUMMARY AIR QUALITY IMPACT ANALYSIS

5.1 Required Analyses[10]

The PSD rules at 40 CFR § 52.21(k) require the permit applicant to demonstrate that, for all regulated air pollutants that would be emitted in excess of the significance thresholds at 40 CFR § 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, data bases, and other requirements specified in 40 CFR 51, Appendix W, Guideline on Air Quality Models.

As discussed in Section 2.2 above, under the proposed OCS/PSD permit for Shell's exploration drilling operations in the Chukchi Sea, potential emissions from the OCS source would be allowed in excess of PSD significance thresholds for CO, NO_x, PM, $PM_{2.5}$, PM_{10}, SO_2 and VOC. Of these pollutants, NAAQS have been promulgated for CO, NO_2 (for NO_x), $PM_{2.5}$, 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 Class I, II and III 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 CFR § 52.21(g). These are defined as all areas not designated Class I, except for any areas redesignated from Class II to Class I or Class III. The area covered by Shell's leases in Lease Sale 193 is a Class II area. See Section 162(b), 42 U.S.C. § 7472(b). No areas have been redesignated to Class III that might be impacted by this project. The PSD Class I and II increments and the NAAQS are listed in the Table 2 of Appendix B.

40 CFR § 52.21(m) requires a PSD permit application to include an air quality analysis in connection with the demonstration required by 40 CFR §52.21(k). For each pollutant for which a NAAQS or PSD increment exists, 40 CFR§ 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 CFR § 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 CFR § 52.21(i)(5)(i), which are also listed in Table 2 of Appendix B. 40 CFR § 52.21(m)(2) requires post-construction ambient air quality monitoring if EPA determines it is necessary to determine the effect that emissions from the

[10] The air quality impact and additional impact analyses are discussed in more detail in Appendix B.

source or modification may have on air quality.

40 CFR § 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. Analysis for vegetation having no significant commercial or recreational value is not required.

For sources impacting Federal Class I areas, 40 CFR§ 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 NAAQS and Increment Analysis

The air quality analysis for NAAQS and increment compliance 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. EPA guidance requires a more detailed air quality analysis if the emission rate is significant, and the predicted maximum concentration of the specific air pollutant is greater than the applicable significant impact level, which are set forth in Table 2 of Appendix B (USEPA 1990 and 1987). As shown in Table 10 of Appendix B, the predicted highest concentration impact from the Discoverer and the Associated Fleet for the applicable averaging time exceeded the significant impact levels for SO_2, NO_2, and PM_{10}. As a result, a detailed ambient air quality impact analysis is required for these three air pollutants. An air quality analysis is also required for ozone because NO_2 and VOC emissions exceed 100 tons per year. See 40 CFR § 52.21(i)(5). In addition, because EPA has not promulgated $PM_{2.5}$ significant impact levels, a NAAQS analysis is required for this air pollutant.

5.2.1 Significant Impact Radii

The significant impact levels are also used to determine the significant impact area radii. The radius is the farthest distance from a stationary source or major modification in which the concentration predicted by an EPA-accepted model exceeds its significant impact level. EPA guidance limits the radius to 50-kilometers. 40 CFR Part 51, Appendix W. In this case, the 24-hour SO_2 and PM_{10}, and annual NO2 significant impact area radius was set to 50-kilometers because the model predictions had not fallen below the threshold for these three air pollutants at this distance.

5.2.2 Baseline Area, Baseline Date, and Trigger Date

For sources locating on the OCS more than 25 miles from the State's seaward boundary, EPA considers the "baseline area" for purposes of 40 CFR § 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. (USEPA 2009c).

Hence, that portion of the Chukchi Sea and Beaufort Sea meeting the above definition is one single baseline area. The "major stationary source baseline date," as defined in 40 CFR § 52.21(b)(14)(i), and the trigger dates for SO_2, NO_2, and PM_{10} for this baseline area are shown below.

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 CFR § 52.21(b)(14)(i). EPA deemed the Shell OCS/PSD application for exploratory drilling in the Chukchi Sea complete on July 31, 2009 (USEPA 2009a), 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 baseline area. As a result, Shell is required to consider emissions from other sources in the area in its analysis of compliance with air quality increments. In this case, however, there are no existing major or minor stationary sources in any of the applicable air pollutant significant impact areas impacted by this permitting action. Because this is the first complete PSD permit application that has been submitted in the baseline area and there are no existing sources, Shell only needs to address its own emissions in conducting the air quality impact analysis. See 40 CFR § 52.21(b)(13), 40 CFR § 52.21(k)(1) and (EPA 1990).

5.2.3 Air Quality Model

In its air quality analysis, Shell used a non-guideline model called ISC3-Prime (USEPA 2004a) in order to better predict the maximum concentration immediately downwind of the hulls of the vessels. The ISC3-Prime model has been evaluated under Arctic conditions (USEPA 2003). EPA believes ISC3-Prime is an appropriate model for determining the air quality impacts from the Discoverer and the Associated Fleet in Arctic conditions and approved the use of ISC3-Prime pursuant to Section 3.2 in 40 CFR Part 51, Appendix W for use in evaluating Shell's permit application and air impact analysis. As provided in 40 CFR § 52.21(l)(2), EPA is requesting public comment on the suitability of use of the ISC3-Prime model in the ambient air quality impact analysis for this permitting action.

5.2.4 Modeled Operating Scenarios

Working with Shell, EPA identified two primary operating scenarios and eleven secondary operating scenarios to analyze in determining air quality impacts. The 13 operating scenarios are listed and briefly described in Table 1 to Appendix B. EPA believes these scenarios are representative of the drilling operations Shell will be conducting in the Chukchi Sea during the

July to December drill season. The two primary operating scenarios are the continuous over water operation of the Discoverer and the Associated Fleet at lease blocks in Lease Sale 193 and the continuous over land operation of an oil fired heater located in a warehouse at an undermined site on-shore. Secondary operating scenarios basically consisted of intermittent, concurrent operations of the Associated Fleet with the Discoverer or operations independent from the Discoverer. The inventory of emissions allowed under the permit from the emission units on the Discoverer and the Associated Fleet were used as inputs in modeling the various scenarios. Since these operations occur over water and in an area lacking any significant industrial and commercial activities or development, the areas are considered rural for dispersion modeling purposes. Auer A. 1978. The modeling analysis used actual dimensions of the structures that cause wake effects, which is a more conservative modeling approach. The assumptions, procedures, emission rates, source types, and stack parameters associated with each modeled operating scenario are discussed in more detail in Appendix B.

In its review of Shell's air quality impact analysis, EPA independently verified the maximum predicted model concentration impacts obtained by Shell by running a simplified version of the model for ten cases for several different scenarios. EPA and Shell modeled SO_2, NO_2, CO, PM_{10} and/or $PM_{2.5}$ concentration impacts differed by at most 0.02 percent, indicating that changes Shell made to the model program code to address the unique aspects of its operations (vessels at sea) had no significant impact on model predictions.

5.2.5 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 or violated increments. For background air monitoring data in its permit application, Shell relies on data collected at a monitoring station in Wainwright, Alaska, one of the few locations on the coast of the Chukchi Sea that has even limited infrastructure. Shell is also relying on data from the Wainwright monitoring station to fulfill the preconstruction monitoring requirement of 40 CFR § 52.21(m). As shown in Table 9 of Appendix B, preconstruction monitoring is required for SO_2, NO_2, and PM_{10} because the predicted highest concentration for these three air pollutants emitted by the Discoverer and the Associated Fleet exceed the respective 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.

There are no islands, platforms or infrastructure in the Chukchi Sea on which to install, operate and maintain ambient air quality monitoring equipment. Wainwright is a rural area with few combustion sources and arctic weather conditions similar to those of the Chukchi Sea. EPA believes that the location of the Wainwright monitoring station is representative of air quality in the area covered by Shell's leases in Lease Area 193 because of the relative closeness of Wainwright to the Shell leases, the relative lack of air pollution sources in Wainwright and the area covered by Shell's leases, and the relative similarity of the meteorology in Wainwright and the area covered by Shell's leases.

The Wainwright monitoring station began collecting data on November 8, 2008. Data measurements include SO_2, NO_2, NO_x, NO, CO, PM_{10}, $PM_{2.5}$ and O_3, with meteorological data being collected at the Wainwright airport. EPA approved the monitoring plan for the Wainwright monitoring station on January 5, 2009. EPA reviewed the quarterly reports including instrument operating parameters and analyzed the measured air pollutant data during the collection period from November 8, 2008 to June 30, 2009 for consistency with 40 CFR § 52.21 and the approved monitoring plan. (CPAI 2009a through 2009b). EPA has concluded that the SO_2, NO_2, NO_x, NO, CO, and O_3 gaseous measurements and PM_{10} data collected from November 8, 2008 to June 30, 2009 are appropriate for use as representative background air quality levels for this permitting action. With respect to $PM_{2.5}$, a problem with the instrumentation rendered the data collected from November 8, 2008 through March 5, 2009 invalid. The problem has since been addressed. USEPA 2009b. $PM_{2.5}$ data collected from March 6, 2009 through June 30, 2009 does meet the requirements of the EPA approved monitoring plan, but does not at this time satisfy the requirement of 40 CFR Part 51, Appendix A, § 3.2.5.5, and 40 CFR § 51.21(m)(3),[11] which requires co-located Federal Reference Method (FRM) and Federal Equivalent Method (FEM) $PM_{2.5}$ samplers at one of the PSD network monitoring stations. Shell is in the process of establishing co-located monitors at one of the PSD network monitoring stations.

Based on information provided by Shell and other available information, EPA believes that a complete and adequate air quality analysis as required by 40 CFR § 51.21(m)(1)(iv) can be accomplished with four months of monitoring data from the Wainwright monitoring site. Measurements of the three gaseous air pollutants (SO_2, NO_2, and CO) generally track with seasonal fluctuations at monitoring stations at other locations on the North Slope. Because the highest concentrations of PM_{10} measured at the Wainwright site were higher than PM_{10} concentrations at other locations on the North Slope, EPA believes that the use of the Wainwright measured PM_{10} concentration data would provide a conservative of background levels for the Chukchi Sea. The monitoring station at Wainwright is the first site on the North Slope with a $PM_{2.5}$ monitor. Because of the lack of significant stationary combustion sources in the area, $PM_{2.5}$ measurements at Wainwright are expected to be low. As low as the concentrations are at Wainwright, the data are conservatively representative of the Shell's leases in the Chukchi Sea, which are even farther away from any sources. EPA therefore believes that a complete and adequate air quality analysis can be accomplished with four months of monitoring data from the Wainwright monitoring site. Additional monitoring data will be included in the record as it becomes available.

5.2.6 Meteorology

Shell used screening meteorology instead of site specific meteorology to predict the ambient air concentration impacts from its exploration drilling operations. Shell modified the screening meteorology by using a lower, more representative ambient temperature of 261.1 K (i.e., -12.1 degrees centigrade or 10.31 degrees Fahrenheit) measured at Barrow, Alaska. The use of the adjusted screening meteorology results in a more conservative approach because it assumes more persistent conditions conducive to high impacts than would be expected to actually occur.

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[11] 40 CFR § 51.21(m)(3) refers to the requirements of Appendix B of 40 CFR Part 58. 40 CFR Part 58 has since been amended, and Appendix B has since been consolidated into Appendix A. of Part 58).

5.2.7 Ozone

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

5.2.8 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. Tables 11 and 12a through 12c to Appendix B show the predicted and total impacts for the primary operating scenarios and modeled secondary operating scenarios. The levels range from a low of 7.10% of the 3-hour SO_2 NAAQS to a high of 96% of the 24-hour $PM_{2.5}$ NAAQS In addition Table 13 to Appendix B shows the predicted total concentration impacts at Point Lay and Wainwright, the two nearest villages to Shell's leases in Lease Sale 193. In these villages, the total predicted impacts for $SO_{2,}$ NO_x, and CO are less than 11% of their respective NAAQS and the total predicted impacts for PM_{10} and $PM_{2.5}$ are less than 50% of their respective NAAQS. Thus, the modeling demonstrates that emissions associated with the proposed permit are not expected to cause or contribute to a violation of the applicable NAAQS.

5.2.9 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 5-1 below shows the predicted concentration impact for Primary Operating Scenario 1 as compared to the PSD increments for Class II areas:

Table 5-1 - Predicted Concentration Impact Comparison with Class II Area Air Quality Increments (Primary Operating Scenario #1)

Air Pollutant	Averaging Period	Predicted ($\mu g/m^3$)	Increment ($\mu g/m^3$)	Percent
Sulfur Dioxide (SO_2)	3-Hour	74.00	512	14.45
	24-Hour	28.00	91	30.77
	Annual	2.10	20	10.50
Nitrogen Dioxide (NO_2)	Annual	20.80	25	83.20
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	28.20	30	94.00
	Annual	1.90	17	11.18
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)			[a]	

a. EPA has not promulgated $PM_{2.5}$ increments.

Predicted impacts for the Class II increments in Point Hope and Wainwright are significantly lower, less than 6% for all SO_2, increments and the 24-hour PM_{10} increment and less than 20% for the annual NO_x increment and the 24-hour PM_{10} increment. See Table 15 to Appendix B.

The nearest Class I area is Denali National Park located about 950-kilometers from the Shell lease blocks in Lease Sale 193. 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 2009a).

5.3 Additional Impacts Analysis

As discussed above, 40 CFR § 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 CFR § 52.21(p) has additional requirements for mandatory federal Class I areas.

5.3.1 Class II Area Visibility

The National Park Service identified two of Class II national monuments as areas of concern (Notar 2009b): Cape Krusenstern National Monument and Bering Land Bridge National Monument. Based on the fact that the nearest Shell lease block in the Chukchi Sea is 280 kilometers from the closest of these national monuments, the National Park Service believes that the Shell project should not adversely affect visibility at the monuments. (Notar. 2009a).

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 degrees Fahrenheit (Martin 2009b). 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. However, because of the location of Shell's operations in the Chukchi Sea, visibility impairment from the exhaust plumes is not expected to be of concern.

5.3.2 Soils and Vegetation

Shell is required to provide an analysis of the impairment to soils and vegetation that is expected to occur as a result of its permitted activities. Analysis for vegetation having no significant commercial or recreational value is not required. All areas within the largest possible significant impact area radius of 50-kilometers centered on the Discoverer are ocean. 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 Chukchi Sea.

5.3.3 Growth

Temporary growth and support facilities are expected at several possible coastal locations to support the project. The location of the growth and facilities could occur at Wainwright, Barrow, Deadhorse and Kotzebue. Support facilities include storage facilities and aircraft hangers. Rotating work crews could lodge at local hotels and trailer camps and helicopters will be used to transport work crews to and from the Frontier Discoverer. In addition, Shell contemplates building a warehouse, heated by either natural gas or heating oil, at either Wainwright or Barrow. The emissions associated with heating the warehouse have been based on oil firing and considered in the modeling analysis and are not expected to contribute to a violation of the NAAQS or noncompliance with PSD increments.

The Helicopter Discoverer 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 horizontal rotors, air quality modeling was not performed for the helicopter take off and landings. Emissions associated with the helicopter are not expected to contribute to a violation of the NAAQS or noncompliance with PSD increments.

5.3.4. Air Quality Related Values Including Visibility

Under 40 CFR § 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 areas are the NPS Denali National Park and the FWS Bering Sea Wilderness Area, located approximately 950-kilometers southeast and 1100-kilometers south, respectively, of Shell's proposed drilling locations in the Chukchi Sea. At this distance, the National Park Service and the Fish and Wildlife Service are not expecting significant sulfate and nitrate deposition, or visibility impairment impacts at these two mandatory federal Class I areas. (Notar 2009a).

5.4 Abbreviated References Cited in Section 5

Auer A. 1978. Correlation of Land Use and Cover with Meteorological Anomalies. Journal of Applied Meteorology, 17(5): 636-643.

CPAI 2009a. Wainwright Near-Term Ambient Air Quality Monitoring Program Monthly Preliminary Data Summary, June 2009. Prepared by AECOM, Inc. July 2009.

CPAI 2009b. Wainwright Near-Term Ambient Air Quality Monitoring Program Monthly Preliminary Data Summary, May 2009. Prepared by AECOM, Inc. July 2009.

CPAI 2009c. Wainwright Near-Term Ambient Air Quality Monitoring Program Second Quarter Data Report, February through April 2009, Final. Prepared by AECOM, Inc. July 2009.

CPAI 2009d. Wainwright Near-Term Ambient Air Quality Monitoring Program First Quarter Data Report, November 2008 through January 2009, Final. Prepared by AECOM, Inc. March 2009.

EPA. 2009a. Letter to Susan Childs, Regulatory Affairs Manager, Alaska Venture, Shell Office Inc. July 31, 2009.

EPA. 2009b. Memorandum from Chris Hall, Air Data Analyst/Air QA Coordinator to Herman Wong, Air Permitting/Air Quality Modeling. July 31, 2009.

EPA. 2009c. Memorandum from David C. Bray to Rick Albright and Janis Hastings. Region 10, Seattle, WA. July 2, 2009.

EPA. 2004a. ISC3 with PRIME Building Downwash - ISC3P, Version 04269. Office of Air Quality Planning and Standards, Research Triangle Park, NC. August 26, 2004.

EPA. 2003. AERMOD: Latest Features and Evaluation Results. Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division. Research Triangle Park, NC. June 2003.

EPA. 1990. Draft New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting. October 1990.

EPA. 1987. Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-0078. Office of Air Quality Planning and Standards, Research Triangle Park, NC. May 1987.

Notar, J. 2009a. Email to H. Wong. EPA Region 10. August 5, 2009.

Notar, J. 2009b. Email to H. Wong. EPA Region 10. June 3, 2009.

6. OTHER LEGAL REQUIREMENTS

6.1 Endangered Species 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 CFR §§ 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 CFR § 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 CFR § 402.07.

The Minerals Management Service (MMS) has served as the Lead Agency for ESA section 7 compliance for Shell's oil exploration activities. The U.S. Fish and Wildlife Service has also completed an intra-agency section 7 consultation in connection with issuance of polar bear incidental take regulations for oil and gas exploration activities in the Chukchi Sea. *See generally* 73 Fed. Reg. 33212 (June 11, 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.

6.2 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 Fisheries (NOAA) with respect to any action authorized, funded, or undertaken by the agency that may adversely affect any essential fish habitat 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 Chukchi Sea. In accordance with the MSA, MMS consulted with the NOAA regarding its Lease Sale 193 in the Chukchi Sea, and the associated affects of oil and gas exploration activities. In its January 30, 2007 letter, NOAA responded to MMS's determination that activities associated with oil and gas exploration may have adverse effects on essential fish habitat by offering Essential Fish Habitat 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.

6.3 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 will consult with the SHPO on Shell's oil exploration activities in federal waters. In fulfilling our NHPA obligations for this permitting action, we intend to rely on these MMS' consultations. We will conduct additional compliance activities necessary to address any EPA-permitted activities not covered in MMS' consultations.

6.4 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 (Clean Air Act); 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.

6.5 Executive Order 12898 – Environmental Justice

Executive Order (EO) 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" (EO 12898), 59 Fed. Reg. 7629 (February 11, 1994), 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 2009), 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. The Region's proposed OCS/PSD air permitting action on the Chukchi 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. Our 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 2009).

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 2009). 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. (NSCP 2009b). In anticipation of a significant degree of public interest in the proposed permit, EPA has scheduled a public hearing, and has considered the timing of subsistence whaling, fishing and hunting in the affected communities in scheduling the public comment period and public hearing. In addition, 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 Chukchi and Beaufort Seas. (ICAS 2009, NSB 2009).

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 CFR §§ 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 Clean Air Act, 42 U.S.C. § 7409(b). EPA specifically solicits comment on our proposed determination that the terms and conditions of the permit ensure attainment of the NAAQS.

6.6 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 Fed. Reg. 67249 (November 9, 2000).

EPA sent letters to 11 potentially interested tribal governments, offering government-to-government consultation opportunities on EPA's proposed action to issue Shell an OCS/PSD permit for exploration drilling on the Chukchi Sea. 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, Native Village of Nuiqsit, Native Village of Kivalina, and Native Village of Kotzebue 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 has also attempted to contact each of these tribal governments to ensure the letters were received.

At this time, EPA has received a request for tribal consultation from the Inupiat Community of the Arctic Slope (ICAS). During a meeting with ICAS representatives, 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 is taking steps to confirm which tribal governments want to participate in government-to-government consultation. Whenever possible, EPA will accommodate requests for consultation received any time during the permitting process.

In addition to notifying affected tribal governments of the opportunity for government-to-government consultation, EPA is also notifying tribal entities and other interested parties 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.

6.7 Abbreviated References Cited in Section 6

EO 13175. Executive Order 13175, "Consultation and Coordination with Indian Tribal Governments," 65 Fed. Reg. 67249 (November 9, 2000).

EO 12898. Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" 59 Fed. Reg. 7629 (February 11, 1994).

EJ GAT. 2009. Demographics profile for all communities of concern, EPA's Environmental Justice Geographic Analysis Tool, July 28, 2009.

ICAS. 2009. Memo to File from Ashley Zanolli with meeting minutes from conference call with ICAS. July 23, 2009.

OEJ. 2009. Environmental Justice Definition, EPA Office of Environmental Justice, http://www.epa.gov/compliance/resources/faqs/ej/index.html#faq2 July 24, 2009.

NSB. 2009. Transcript of conference call with Jonathan Jemming of the North Slope Borough. June 26, 2009.

NSCP. 2009. "North Slope Communications Protocol: Communications Guidelines to Support Meaningful Involvement of the North Slope Communities in EPA Decision-Making," EPA Region 10, May 2009

NSCP. 2009b Memo to file from Nancy Helm about Early Outreach to North Slope Communities. June 18, 2009.

Exhibit 8
AEWC & ICAS

APPENDIX A

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

Summary of Annual Emissions

Frontier Discoverer Sources

Unit ID	Description	Make/Model	Potential to Emit (tons/year) 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	0.02	0.08	4.04E-04
FD-2	Generator Engine	Caterpillar D399	0.56	1 55	0.40	0.40	0.02	0.08	4.04E-04
FD-3	Generator Engine	Caterpillar D399	0.56	1 55	0.40	0.40	0.02	0.08	4.04E-04
FD-4	Generator Engine	Caterpillar D399	0.56	1 55	0.40	0.40	0.02	0.08	4.04E-04
FD-5	Generator Engine	Caterpillar D399	0.56	1 55	0.40	0.40	0.02	0.08	4.04E-04
FD-6	Generator Engine	Caterpillar D399	0.56	1 55	0.40	0.40	0.02	0.08	4.04E-04
FD-7[1]	Propulsion Engine	MI / 6UEC65	0.00	0 00	0.00	0.00	0.00	0.00	0.00
FD-8	Emergency Generator	Caterpillar 3304	7 20E-03	1.31E-02	2.52E-03	2.52E-03	5.85E-06	1.32E-03	1.06E-07
11[2]	MLC Compressor	Caterpillar C-15	4.70	5 37	0.27	0.27	8.63E-03	5.37E+00	1.57E-04
FD-12-13[3]	HPU Engine	Detroit/8V71	0.25	8.18	0.16	0.16	4.71E-03	0.12	8.56E-05
FD-14-15[4]	Deck Cranes	Caterpillar D343	0.20	9 50	0.07	0.07	6.76E-03	0.06	1.23E-04
FD-16-20[5]	Cementing Units and Logging Winches	Various	0.71	12.77	0.31	0.31	6.15E-03	0.61	1.12E-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	1.99	0 32	0.45	0.53	0.16	0.19	1.36E-02
FD-24-30[6]	Fuel Tanks	NA						0.01	
FD-31	Supply Ship at Discoverer	NA	0.09	0.43	0.03	0.03	0.02	0.03	2.85E-06
FD-32[7]	Drilling Mud System	NA						0.07	
FD-33[8]	Shallow Gas Diverter System	NA						0.00	
	Sub-Total Emissions from Frontier Discoverer		13.81	52.34	4.45	4.52	0 38	6.99	0.02

Associated Fleets

Description	Potential to Emit (tons/year) CO	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC	Lead
Ice Management Fleet - Generic							
Ice Breaker # 1	345.38	849.47	85.08	96.76	83 90	69.11	4.41E-02
Ice Breaker #2	345.38	849.47	85.08	96.76	83 90	69.11	4.41E-02
Resupply Ship - Generic	0.56	4 24	0.26	0.32	0.16	0.10	2 06E-05
OSR Fleet - Generic							
Nanuq - Main Ship	55.33	169.73	8.47	10.62	7.80	19.60	3.10E-02
Oil Spill Response, Kvichak No. 1, 2 and 3 Work Boats	1.72	39.39	0.78	0.78	5 23	0.80	7 51E-04
Sub-Total Emissions from Fleets	748.36	1,912.29	179.66	205.25	180 98	158.72	0.12
TOTAL PROJECT EMISSIONS	762.16	1964.63	184.11	209.77	181 36	165.71	0.14

Notes

1 Propulsion engine is not used from when first anchor is set at each location to when the last anchor is retrieved.
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 Combined use of both deck cranes are limited by an aggregate fuel usage limit.
5 Combined use of all five cementing unit and logging winch engines are limited by an aggregate fuel usage limit.
6 Tanks calculations and software outputs are listed separately but are summarized in this table.
7 Drilling mud system calcula ions are listed separately but are summarized in this table.
8 Shallow gas diverter system is not expected to be used as part of planned operations

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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 NOx, 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	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 2-23-2009, Appendix B, page 28
NO_x	From 10-9-2008 D.E.C. Marine letter to Shell. See permit application dated February 23, 2009, Appendix F, page 6
$PM_{2.5}$	PM2.5 emissions assumed to be same as PM10 emissions
PM_{10}	From Caterpillar, See permit application dated February 23, 2009, Appendix B, page 28
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 4/6/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
3 Fuel usage from Caterpillar, See permit application dated February 23, 2009, Appendix B, page 28
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 Shell's *Response to EPA R10 March 11, 2009, Letter of Incompleteness*, dated 5/18/2009 71% load

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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.

			Maximum Hours of Operation[4]			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	6.2	g/hp-hr	0.33	8		0.6	0 6	7.20E-03	0.076	0.003	2 07E-04
NO_x	11.28	g/hp-hr	0.33	8		1.09	1.09	1.31E-02	0.137	0.006	3.76E-04
$PM_{2.5}$	2.21	g/hp-hr	0.33	8		0.21	0.21	2.52E-03	0.026	0.001	7 25E-05
PM_{10}	2.21	g/hp-hr	0.33	8		0.21	0.21	2.52E-03	0.026	0.001	7 25E-05
SO_2	0.000030	lb/lb fuel	0.33	8		4 88E-04	4.88E-04	5.85E-06	6.14E-05	2.56E-06	1 68E-07
VOC	1.163	g/hp-hr	0.33	8		0.11	0.11	1.32E-03	1.39E-02	5.77E-04	3 80E-05
Lead	0.000029	lb/MMBtu	0.33	8		8 86E-06	8.86E-06	1.06E-07	1.12E-06	4.65E-08	3 06E-09

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
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
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 20 minutes of operation per week, to ensure operability when needed.

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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.

			Maximum Operation[4, 5]			**Potential to Emit**			**Potential to Emit in g/sec**		
Pollutant	**Emission Factors**[4]	**Emission Factor Units**	**Daily (hrs)**	**Annual (gal)**	**Control Efficiency**	**Hourly, lb/hr**	**Daily, lb/day**	**Annual, tpy**	**One-Hour**	**24-Hour**	**365-Day**
CO	3.5	g/kW-h	24	81,346		3.11	74.64	4.70	0.392	0.392	0.135
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		0.18	4 32	0 27	0.023	0.023	0.008
PM_{10}	0.2	g/kW-h	24	81,346		0.18	4 32	0 27	0.023	0.023	0.008
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	From Tier 3 emission limit in 40 CFR 89.112		
NO_x	From Tier 3 emission limit in 40 CFR 89.112		
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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		
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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
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

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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 and daily emissions are on a per-engine basis. Annual emissions are for both HPU engines in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[6, 7] Daily (hrs)	Maximum Operation[6, 7] Annual (gal)	Control Efficiency[4, 5]	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual[7], 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	2.99	g/hp-hr	24	44,338	0.9	0.16	3 84	0.25	0.02	0 02	0.007
NO_x	9.81	g/hp-hr	24	44338		5.41	129.84	8.18	0.682	0.682	0.235
$PM_{2.5}$	1.26	g/hp-hr	24	44338	0.85	0.10	2.40	0.16	0.013	0.013	0.005
PM_{10}	1.26	g/hp-hr	24	44338	0.85	0.10	2.40	0.16	0.013	0.013	0.005
SO_2	0.000030	lb/lb fuel	24	44338		3.11E-03	0 07	4.71E-03	3.92E-04	3.67E-04	1 35E-04
VOC	1.48	g/hp-hr	24	44338	0.9	0.08	1 92	0.12	1.01E-02	1.01E-02	3 55E-03
Lead	0.000029	lb/MMBtu	24	44338		5.66E-05	1.36E-03	8.56E-05	7.13E-06	7.13E-06	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
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
3 Fuel usage per permit application dated February 23, 2009, Appendix B, page 34
0.415 lb/hp-hr
4 PM10 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 CleanA R 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 is based on hours of operation
7 Annual maximum operation is based on fuel usage for both engines: 44,338 gallons

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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]		Control Efficiency[4, 5]	Potential to Emit			Potential to Emit in g/sec		
			Daily (hrs)	Annual (gal)[8]		Hourly, lb/hr	Daily, lb/day	Annual[8], tpy	One-Hour	24-Hour	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]
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
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 PM10 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 CleanA R 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 Shell *Response to EPA R10 March 11, 2009 Letter of Incompleteness*, Attachment D, Page 3, dated 5/18/2009
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.

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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
CO	2.99	g/hp-hr			0.9	0.22			0.028
NO_x	9.81	g/hp-hr				7.25			0.913
$PM_{2.5}$	1.26	g/hp-hr			0.85	0.14			0.018
PM_{10}	1.26	g/hp-hr			0.85	0.14			0.018
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
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
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1

2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1

3 Fuel usage per permit application dated February 23, 2009, Appendix B, page 34
0.415 lb/hp-hr

4 PM10 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 CleanA R 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 Chukchi 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™ 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
CO	6.55	g/hp-hr			0.9	0.21			0.026
NO_x	11.72	g/hp-hr				3.8			0.479
$PM_{2.5}$	1.92	g/hp-hr			0.85	0.09			0.011
PM_{10}	1.92	g/hp-hr			0.85	0.09			0.011
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
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]
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
3 Fuel usage per permit application dated February 23, 2009, Appendix B, page 34
0.415 lb/hp-hr
4 PM10 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 CleanA R 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 Chukchi Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit	FD-19	Logging Winch
Make/Model[1]	Detroit 4-71N	
Fuel	Liquid distillate, #1 or #2	
Rating[2]	128	hp
Maximum Hourly Fuel Use[3]	53	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[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
CO	6.55	g/hp-hr	[redacted]	[redacted]	0.9	0.18	[redacted]	[redacted]	0.023
NO_x	11.72	g/hp-hr	[redacted]	[redacted]		3.31	[redacted]	[redacted]	0.417
$PM_{2.5}$	1.92	g/hp-hr	[redacted]	[redacted]	0 85	0.08	[redacted]	[redacted]	0.01
PM_{10}	1.92	g/hp-hr	[redacted]	[redacted]	0 85	0.08	[redacted]	[redacted]	0.01
SO_2	0.000030	lb/lb fuel	[redacted]	[redacted]		1 59E-03	[redacted]	[redacted]	2.01E-04
VOC	2.01	g/hp-hr	[redacted]	[redacted]	0.9	0.06	[redacted]	[redacted]	7.56E-03
Lead	0.000029	lb/MMBtu	[redacted]	[redacted]		2 90E-05	[redacted]	[redacted]	3.65E-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]
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
3 Fuel usage per permit application dated February 23, 2009, Appendix B, page 34
0.415 lb/hp-hr
4 PM10 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 CleanA R 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 Chukchi Sea Exploration Drilling Program
Criteria Pollutant Emission Inventory

Emissions Unit	FD-20	Logging Winch		
Make/Model[1]	John Deere 4024TF			
Fuel	Liquid distillate, #1 or #2			
Rating[2]	48	hp	converted from	36 kW
Maximum Hourly Fuel Use[3]	17.9	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]		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
CO	5.5	g/kW-hr			0.9	0.04			0.005
NO_x	7.5	g/kW-hr				0.6			0.076
$PM_{2.5}$	0.60	g/kW-hr			0.85	0.01			0.001
PM_{10}	0.60	g/kW-hr			0.85	0.01			0.001
SO_2	0.000030	lb/lb fuel				5.37E-04			6.77E-05
VOC	7.5	g/kW-hr			0.9	0.08			1.01E-02
Lead	0.000029	lb/MMBtu				9.76E-06			1.23E-06

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		
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Engine rating per permit application dated February 23, 2009, Appendix B, page 1
3 Fuel usage from engine specifications, attached to April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
4 PM10 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 CleanA R 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

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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 (
Control Equipment	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC on all engines

Emissions are for all cementing unit and logging winch engines in aggregate.

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[1] Daily (gal)	Annual (gal)	Control Efficiency[3]	Potential to Emit[2] Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec 24-Hour	365-Day
CO	6.55	g/hp-hr	345	57,960	0.9	[redacted]	8.49	0.71	0 045	0.021
NO_x	11.72	g/hp-hr	345	57,960		[redacted]	151.99	12.77	0.798	0.367
$PM_{2.5}$	1.92	g/hp-hr	345	57,960	0 85	[redacted]	3.73	0.31	0.02	0.009
PM_{10}	1.92	g/hp-hr	345	57,960	0 85	[redacted]	3.73	0.31	0.02	0.009
SO_2	0.00003	lb/lb fuel	345	57,960		[redacted]	0.07	6.15E-03	3.84E-04	1.77E-04
VOC	5.59	g/hp-hr	345	57,960	0.9	[redacted]	7.25	0.61	3.81E-02	1.75E-02
Lead	0.000029	lb/MMBtu	345	57,960		[redacted]	1.33E-03	1.12E-04	6.99E-06	3.22E-06

Emissions Factor References

CO	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 21
NO_x	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 21
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 emissions
PM_{10}	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 21
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 21
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: 345 gallons per day
Per Shell *Response to EPA R10 March 11, 2009, Letter of Incompleteness*, Attachment D, Page 3, dated 5/18/2009
2 Emissions are for all cementing unit and logging winch engines in aggregate.

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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
CO	14.8	lbs/day	24	4,032		0.62	14.8	1.25	0.078	0.078	0 036
NO_x	38.50	lbs/day	24	4,032		1.6	38.50	3.23	0.202	0.202	0 093
$PM_{2.5}$	4.50	lbs/day	24	4,032		0.19	4.50	0.38	0.024	0.024	0 011
PM_{10}	4.50	lbs/day	24	4,032		0.19	4.50	0.38	0.024	0.024	0 011
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
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
$PM_{2.5}$	PM2 5 emissions assumed to be same as PM10 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 February 23, 2009, Appendix B, page 1
2 Boiler rating per permit application dated February 23, 2009, Appendix B, page 1
3 Fuel usage converted based on boiler rating, fuel density and fuel heat content.

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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				

Emissions are on a per incinerator basis at 100% load

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation, lbs of Waste[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	31	lbs/ton	1525	256,200		4.28	23 64	1.99	0.539	0.124	0.057
NO_x	5	lbs/ton	1525	256,200		0.69	3 81	0.32	0.087	0 02	0.009
$PM_{2.5}$	7.00	lbs/ton	1525	256,200		0.97	5 34	0.45	0.122	0.028	0.013
PM_{10}	8.2	lbs/ton	1525	256,200		1.13	6 25	0.53	0.143	0.033	0.015
SO_2	2.5	lbs/ton	1525	256,200		0.35	1 91	0.16	4.35E-02	1.00E-02	4.61E-03
VOC	3	lbs/ton	1525	256,200		0.41	2 29	0.19	5.22E-02	1.20E-02	5.53E-03
Lead	0.213	lbs/ton	1525	256,200		0.03	0.16	1.36E-02	3.70E-03	8.53E-04	3.92E-04

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 5/18/2009 *Response to EPA R10 March 11, 2009, Letter of Incompleteness*, Attachment D, Page 3
PM_{10}	Owner requested limit per Shell 5/18/2009 *Response to EPA R10 March 11, 2009, Letter of Incompleteness*, Attachment D, Page 3
SO_2	Owner requested limit per Shell 5/18/2009 *Response to EPA R10 March 11, 2009, Letter of Incompleteness*, Attachment D, Page 3
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
7.076	lbs/gal
133,098	Btu/gal

Footnotes/Assumptions

1 Incinerator specification per permit application dated February 23, 2009, Appendix B, page 1
2 Incinerator can burn municipal wate or sewage - emission factors are maximum for these two waste feeds
3 Incinerator rating per permit application dated February 23, 2009, Appendix F, page 16
4 Daily and annual usage limits are based on owner requested limits per 5/12/2009 e-mail from Air Sciences (Sabrina Pryor) to EPA (Pat Nair).

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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]		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	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	0.0038	lb/lb fuel	12	96		0.41	4.96	0 02	0.052	0.026	5.70E-04
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
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 February 23, 2009, Appendix B, page 15
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

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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]	22720	hp
Aggregate Rating, Generation Engines[1]	2800	hp
Aggregate Rating, External Combustion[1]	10	MMBtu/hr
Maximum Hourly Fuel Use[2]	1,417	gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Fuel Usage (gallons)[3] Daily	Annual	Control Efficiency	Potential to Emit[3] 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	34,015	5,714,560		148.22	3557.21	298 81	18.675	18.675	8 596
NO_x	25	g/kW-hr	34,015	5,714,560		1107.58	26582.00	849 00	139.552	139.552	24.423
$PM_{2.5}$	0.22	lb/MMBtu	34,015	5,714,560		41.50	996.02	83 67	5.229	5.229	2.407
PM_{10}	NA	NA	NA	NA		46.98	1127.42	94.70	5.919	5.919	2.724
SO_2	0.93	g/kW-hr	34,015	5,714,560		41.42	994.14	83 51	5.219	5.219	2.402
VOC	0.60	g/kW-hr	34,015	5,714,560		26.58	637.97	53 59	3.349	3.349	1 542
Lead	2.90E-05	lb/MMBtu	34,015	5,714,560		5.47E-03	1.31E-01	1.10E-02	6.89E-04	6.89E-04	3.17E-04

Emissions Factor References

CO, SO_2, 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 21

NOx, $PM_{2.5}$ Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).

PM_{10} Owner requested limit per Shell 5/18/2009 *Response to EPA R10 March 11, 2009 Letter of Incompleteness*, Attachment D, Page 3

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]	154.00	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	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

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 Owner requested limits per 5/14/2009 e-mail and attachments from Air Sciences (Rodger Steen) to EPA (Pat Nair), and Shell 5/29/2009 *Supplemental Response to EPA R10 March 11, 2009 ,Letter of Incompleteness*, Attachment D, Pages D.1-1 - 4

Limits apply to incinerators, engines and boilers - see page 21

Applicant has asked for the following limits for Icebreakers #1 and 2 in aggregate:

Annual fuel usage limit:	11,429,120	gallons	PM2 5 hourly emissions limit:	84.4	lbs
Annual NOx emissions limit:	1699	tpy	PM10 hourly emissions limit:	96 0	lbs

This emission inventory reflects Icebreaker #2 operating at its maximum allowed level as follows:

Annual fuel usage limit:	5,714,560	gallons	PM2 5 hourly emissions limit:	42 2	lbs
Annual NOx emissions limit:	849	tpy	PM10 hourly emissions limit:	48 0	lbs

Consequently, the emissions presented for Icebreaker #1 reflect the remaining allowable emissions for this source category.

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

Fleet Unit	Ice Breaker #2	
Fuel	Liquid distillate, #1 or #2, and waste materials for incinerator	
Equipment Type	Internal Combustion Engines	
Aggregate Rating, Propulsion Engines[1]	22720	hp
Aggregate Rating, Generation Engines[1]	2800	hp
Aggregate Rating, External Combustion[1]	10	MMBtu/hr
Maximum Hourly Fuel Use[2]	1,417	gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Fuel Usage (gallons)[3] Daily	Annual	Control Efficiency	Potential to Emit[3] 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	34,015	5,714,560		148.22	3557.21	298 81	18.675	18.675	8 596
NO_x	25.40	g/kW-hr	34,015	5,714,560		1125.35	27008.42	849 00	141.791	141.791	24.423
$PM_{2.5}$	0.22	lb/MMBtu	34,015	5,714,560		41.50	996.02	83 67	5.229	5.229	2.407
PM_{10}	NA	NA	NA	NA		46.98	1127.42	94.70	5.919	5.919	2.724
SO_2	0.93	g/kW-hr	34,015	5,714,560		41.42	994.14	83 51	5.219	5.219	2.402
VOC	0.60	g/kW-hr	34,015	5,714,560		26.58	637.97	53 59	3.349	3.349	1 542
Lead	2.90E-05	lb/MMBtu	34,015	5,714,560		5.47E-03	1.31E-01	1.10E-02	6.89E-04	6.89E-04	3.17E-04

Emissions Factor References

CO, SO_2, 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 21

NOx, $PM_{2.5}$, PM_{10} Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).

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]	154.00	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	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

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 Owner requested limits per 5/14/2009 e-mail and attachments from Air Sciences (Rodger Steen) to EPA (Pat Nair), and Shell 5/29/2009 *Supplemental Response to EPA R10 March 11, 2009 ,Letter of Incompleteness*, Attachment D, Pages D.1-1 - 4
Limits apply to incinerators, engines and boilers - see page 21

Annual fuel usage limit:	5,714,560	gallons	PM2 5 hourly emissions limit:	42 2	lbs
Annual NOx emissions limit:	849	tpy	PM10 hourly emissions limit:	48	lbs

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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] 6344 hp
Maximum Hourly Fuel Use[2] 334 gallons/hour
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	0.93	g/kW-hr	4	32		9.75	39.01	0.16	1.229	0.205	0.004
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 21

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
Hourly emissions are based on 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
	6344 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 e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair):
based on a 4-hour round trip from the 25-mile distance to the Discoverer and 8 annual trips

Exhibit 8
AEWC & ICAS

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi 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 hp

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2]		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr[3]	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	0.73	g/kW-hr	1,547	259,896		6.50	39.04	3.28	0.82	0.205	0.094
NO_x	13.62	g/kW-hr	1,547	259,896		121.32	728.13	61.16	15.287	3.823	1.759
$PM_{2.5}$	0.17	g/kW-hr	1,547	259,896		1.51	9.09	0.76	0.191	0.048	0.022
PM_{10}	0.17	g/kW-hr	1,547	259,896		1.51	9.09	0.76	0.191	0.048	0.022
SO_2[2,4]	0.0038	lb/lb fuel	1,547	259,896		6.93	41.60	3.49	0.873	0.218	0.10
VOC	0.99	g/kW-hr	1,547	259,896		8.82	52.94	4.45	1.111	0.278	0.128
Lead	0.000029	lb/MMBtu	1,547	259,896		9.95E-04	5.97E-03	5.02E-04	1.25E-04	3.13E-05	1.44E-05

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC Permit application dated February 23, 2009, Appendix B, page 51
NOx NOx emission factor was converted from NO to NO2 1.53
SO2 Sulfur content of fuel: 0.0019 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 Other Internal Combustion Engines
Aggregate Rating[1] 2570 hp
Owner Requested Limit (Daily, Annual)[2] 1285 hp
Maximum Hourly Fuel Use[2] 68 gal/hr

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (gallons)[2]		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	3.35	g/kW-hr	1,622	272,496		14.14	169.62	14.25	1.781	0.891	0.41
NO_x	25.40	g/kW-hr	1,622	272,496		107.32	1287.88	108.18	13.522	6.761	3.112
$PM_{2.5}$	1.54	g/kW-hr	1,622	272,496		6.51	78.08	6.56	0.82	0.41	0.189
PM_{10}	1.92	g/kW-hr	1,622	272,496		8.11	97.35	8.18	1.022	0.511	0.235
SO_2	0.935	g/kW-hr	1,622	272,496		3.95	47.41	3.98	0.498	0.249	0.12
VOC	0.60	g/kW-hr	1,622	272,496		2.54	30.42	2.56	0.319	0.16	0.074
Lead	0.000029	lb/MMBtu	1,622	272,496		5.22E-04	6.26E-03	5.26E-04	6.57E-05	3.29E-05	1.51E-05

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 21
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		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	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	0.03	1.68E-03	1.68E-03	8.63E-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 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

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

Fleet Unit Oil Spill Response Main Ship - Nanuq (continued)

Footnotes/Assumptions

1 Equipment population, rating and usage based on vessel Nanuq per permit application dated February 23, 2009, Appendix B, page 16
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):

Propulsion Engines limited to 1 engine at 50% of rated capacity, i.e.	1355	hp
Maximum fuel usage:	1547	gal/day
Equivalent to only one generator to be operated - total hp:	1285	hp
Maximum fuel usage:	68	gal/hr

3 Fuel usage per permit application dated February 23, 2009, Appendix B 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

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Criteria Pollutant Emission Inventory

Fleet Unit: Oil Spill Response, Kvichak 34-foot No. 1, 2 and 3 Work Boats (three)
Fuel: Liquid distillate, #1 or #2

Equipment Type: Internal Combustion Engines - propulsion
Make/Model[1]: Cummins QSB
Aggregate Rating[1]: 1800 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		0.62	15	1.24	0.078	0 078	0.036
NO_x	4.644	g/hp-hr	24	4,032		18.43	442	37.15	2.322	2.322	1.069
$PM_{2.5}$	0.077	g/hp-hr	24	4,032		0.31	7	0.62	0.039	0.039	0.018
PM_{10}	0.077	g/hp-hr	24	4,032		0.31	7	0.62	0.039	0.039	0.018
SO_2	0.0038	lb/lb fuel	24	4,032		2.55	61	5.13	0.321	0.321	0.148
VOC	0.078	g/hp-hr	24	4,032		0.31	7	0.62	0.039	0 039	0.018
Lead	0.000029	lb/MMBtu	24	4,032		3.65E-04	0.01	7.37E-04	4.60E-05	4.604E-05	2.12E-05

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC From permit application dated February 23, 2009, Appendix B, page 64
PM2.5 and PM10 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]: 36 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		0.24	6	0.48	0.03	0.03	0.014
NO_x	4.410	lb/MMBtu	24	4,032		1.11	27	2.24	0.14	0.14	0.064
$PM_{2.5}$	0.31	lb/MMBtu	24	4,032		0.08	2	0.16	0.01	0.01	0.005
PM_{10}	0.31	lb/MMBtu	24	4,032		0.08	2	0.16	0.01	0.01	0.005
SO_2	0.0038	lb/lb fuel	24	4,032		0.05	1	0.10	0.006	0 006	0.003
VOC	0.35	lb/MMBtu	24	4,032		0.09	2	0.18	0.011	0 011	0.005
Lead	0.000029	lb/MMBtu	24	4,032		7.31E-06	1.75E-04	1.47E-05	9.21E-07	9.208E-07	4.24E-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 popula ion, rating and usage based on 3 work boats per permit application dated February 23, 2009, Appendix B, pages 16, 67 - Each of three identical Kvichak 34-foot boats has two 305 hp propulsion engines and a 12 hp generator
2 7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content
3 Sulfur content of fuel: 0.0019 by weight

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer Chukchi Sea Exploration Drilling Program
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 Uncontrolled Emission Factors for Cementing Units and Logging Winches

Pollutant	Detroit 8V71N Emission Factors	Detroit 3V-71 and 4-71 Emission Factors	Emission Factor Units	John Deere Emission Factors, uncontrolled	Emission Factor Units	Emission Factors	Emission Factor Units	Maximum Emission Factor	Emission Factor Units
CO	2.99	6.55	g/hp-hr	5.5	g/kW-hr	4.1	g/hp-hr	6.55	g/hp-hr
NO_x	9.81	11.72	g/hp-hr	7.5	g/kW-hr	5.59	g/hp-hr	11.72	g/hp-hr
$PM_{2.5}$	1.26	1.92	g/hp-hr	0.60	g/kW-hr	0.45	g/hp-hr	1.92	g/hp-hr
PM_{10}	1.26	1.92	g/hp-hr	0.60	g/kW-hr	0.45	g/hp-hr	1.92	g/hp-hr
SO_2	0.000030	0 000030	lb/lb fuel	0.000030	lb/lb fuel	0 000030	lb/lb fuel	0.00003	lb/lb fuel
VOC	1.48	2.01	g/hp-hr	7.5	g/kW-hr	5.59	g/hp-hr	5.59	g/hp-hr

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]	0.0015371	0.93	0	0.798	0.93
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]	0.93	29.23	26.98	29.23
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

Exhibit 8
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APPENDIX B

AMBIENT AIR QUALITY IMPACT ANALYSIS

The Statement of Basis (SB) provided a description of the Shell Chukchi Sea exploratory drilling project, and detailed the potential to emit and significant emission rates of all applicable air pollutants. The total project emission rates of nitrogen dioxide (NO_2) (or oxides of nitrogen (NO_x)) and carbon monoxide (CO) exceed 250 tons per year making it a major stationary source under the Prevention of Significant Deterioration (PSD) regulation, 40 CFR Part 52.21. Furthermore, the net emission rates of sulfur dioxide (SO_2), NO_2, CO, particulate matter less than or equal to ten microns (PM_{10}), particulate matter less than or equal to 2.5 microns ($PM_{2.5}$), and ozone (O_3) (represented by volatile organic compounds (VOC) and NO_x) exceed their significant emission rate threshold and as a result, subjects these six air pollutants to the PSD requirements in paragraphs (k) to (p) of 40 CFR Part 52.21. Essentially, Shell must demonstrate that its project will comply with National Ambient Air Quality Standards (NAAQS) and PSD air quality increments at all affected Class I and Class II areas, and will not adversely impact air quality related values (AQRV) at mandatory Federal Class I areas. Shell must also analyze project impacts on growth, soils and vegetation, and visibility impairment, which is cumulatively known as "additional impacts analysis." Except for the Class I area impact analyses, the demonstrations and analyses are generally limited to the significant impact area of each applicable air pollutant within the Class II area.

A. Overview

In its review of PSD ambient air quality impact analyses, the U.S. Environmental Protection Agency (EPA) relies on the requirements contained in existing laws, regulations, standards, guidance, memorandums, and policies to determine if provided compliance demonstrations are adequate and acceptable. EPA also employs its technical/scientific judgment on a case-by-case basis to modify, develop or review new procedures, methods, techniques or models to address unique circumstances when there is inadequate or no applicable requirement

The Shell project ambient air quality impact analyses are different from most that are received and reviewed by EPA in that (1) exploratory drilling operations will occur seaward of the outer continental shelf (OCS) in the Chukchi Sea, (2) drilling will occur at different lease blocks in Lease Sale Area 193, and (3) combustion units are on board stationary and moving vessels. Vessels include the Frontier Discoverer drill ship, an ice breaker fleet, an oil spill response fleet that includes three work boats, and a supply ship. The Frontier Discoverer is considered an OCS stationary source when its first of eight anchors is attached to the sea floor and up until the last of the eight anchors is lifted from the sea floor (see SB for details).

For the ambient air quality impact analyses, EPA divided the drilling operations into a primary operating scenario (POS) group and a secondary operating scenario (SOS) group to review and determine project compliance with the PSD regulation, 40 CFR Part 52.21. Working with Shell, EPA identified two POS's and 11 SOS's. The 13 operating scenarios are listed and briefly described in Table 1. EPA believes these scenarios are representative of the drilling operations during the Shell July to December drill season. (Shell 2008, 2009a, and 2009b).

POS #1 is the continuous over water operation of the Frontier Discoverer drill ship (as a stationary source), ice breaker fleet and oil spill response fleet combustion units at lease blocks in Lease Sale Area 193. Lease Sale Area 193 is about 110-km northwest of Wainwright, Alaska. POS #2 is the continuous over land operation of an oil fired heater located in a warehouse at an undermined site. Secondary operating scenarios basically consist of intermittent, concurrent operations with the Frontier Discoverer or independent operations from the Frontier Discoverer. The SB contains a discussion of the emission rates of each combustion unit on board the drill ship, vessels composing the two fleets and the supply ship in each of the 13 operating scenarios.

The operating scenarios are evaluated either quantitatively or qualitatively. POS #1 and #2 are evaluated quantitatively. Since SOS #1 to #4 will operate during drilling operations, the scenarios are also evaluated quantitatively. SOS #5 and #6 will operate independent of POS #1 and are quantitatively analyzed to confirm that their operations would not exceed 24-hour $PM_{2.5}$ NAAQS. The remaining five SOS's are evaluated qualitatively as described below.

- SOS #7. Power to realign the Frontier Discoverer bow into the prevailing wind direction will come from generators that are already operating as a result of drilling operations. The occurrence of realignment should not increase the drill ship generator emission rates under POS #1. (Winges, K. 2009e)

- SOS #8. Besides providing lift, the helicopter horizontal rotor(s) also provide a mechanism to immediately disperse emissions generated by its engine. Emissions from the helicopters are not expected to have a significant impact in it's area of operation.

- SOS #9. The ice breaker fleet will operate under the same mode as first year ice to crush multi year ice. Hence, the crushing of multi year ice should not increase vessel emission rates under POS #1.

- SOS #10. When the ice breaker fleet services are not needed, it will locate at least 25 miles away from the drilling operations. At this distance, the ice breaker vessel emissions are not considered to be emissions from an OCS source (40 CFR Part 55.2).

- SOS #11. Like SOS #10, the supply ship will locate at least 25 miles away from the drilling operations when it is not replenishing the Frontier Discoverer. At this distance, the emissions from the supply ship are not considered to be emissions from an OCS source (40 CFR Part 55.2).

To determine compliance quantitatively per the PSD regulation, the calculated significant emission rates associated with eight operating scenarios are modeled and the predicted concentration impacts of the air pollutants are compared to their NAAQS, PSD air quality increments, significant impact levels and/or ambient monitoring thresholds as shown in Table 2.

As provided in 40 CFR Part 50.2, the primary and secondary NAAQS that appear in Table 2 are designed to protect the public health and welfare everywhere in the fifty states.

Class I, II, and III area air quality increments are designed to allow limited growth based on predicted concentrations in areas meeting the NAAQS. Class I areas have the most stringent increments and allow the smallest degree of air quality deterioration. Class II areas allow for well managed development. Class III areas have the largest increments and permit a larger degree of development and air quality deterioration than the other two areas (USEPA 1990). As there are no Class III areas, Table 2 lists only the maximum air quality deterioration in Class I and II areas.

Section 162 of the Clean Air Act of 7 August 1977 established mandatory Federal Class I areas which include international parks, national wilderness areas which exceed 5,000 acres, national memorial parks which are greater than 5,000 acres, and national parks which exceed 6,000 acres. The protection of these areas is the responsibility of either the Forest Service (FS), National Park Service (NPS), or Fish and Wildlife Service (FWS) (40 CFR Part 52.21(b)(24) and (o)).

If the emission rate is significant as discussed in the SB, and the predicted maximum concentration of the specific air pollutant is greater than an applicable significant impact level identified in Table 2, a more detailed ambient air quality modeling analysis should be completed by the project proponent (USEPA 1987 and 1990). The analysis could include the collection and use of site specific meteorology in an EPA refined air quality model rather than the use of a screening model. In terms of analysis, an allowable emissions inventory and an actual emissions inventory of nearby sources must be developed and modeled with project emissions to determine compliance with NAAQS and air quality increments. Because EPA has not promulgated $PM_{2.5}$ significant impact levels, a NAAQS analysis is required for this air pollutant.

The significant impact levels are also used to obtain significant impact area radii. The radius is the farthest distance from a proposed major stationary source or major modification in which the concentration predicted by an EPA accepted model exceeds its significant impact level. EPA guidance limits the radius to 50-kilometers (Appendix W of

40 CFR Part 51).

If the predicted maximum concentration for a specific air pollutant exceeds an ambient monitoring threshold for an applicable air pollutant as shown in Table 2, a 12 month preconstruction ambient air quality monitoring program is required by 40 CFR Part 52.21(m)(1)(iv) unless EPA determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a short period of not less than four months. In certain cases, representative air quality data measurements may be used in lieu of a preconstruction monitoring program provided the monitoring location, data quality, and currentness criteria are satisfied (USEPA 1987). The measured data is used in conjunction with model predictions to determine if project total air quality concentration impacts meet the NAAQS.

The specific assumptions and methodologies employed by Shell and reviewed by EPA for consistency with regulatory requirements, and sound technical judgement and science are discussed in the following sections. It should be noted that Shell used a non-guideline model called ISC3-Prime (USEPA 2004a). EPA approved the use of ISC3-Prime pursuant to Section 3.2 in Appendix W of 40 CFR Part 51 in order to capture the predicted maximum concentrations in the wake region of the vessels. Also, the ISC3-Prime model has been evaluated under Arctic conditions (USEPA 2003).

B. Baseline Area, Baseline Date, and Trigger Date

For sources locating on the OCS more than 25 miles from the State's seaward boundary, EPA considers the "baseline" area for purposes of 40 CFR Part 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 (USEPA 2009c).

Hence, that portion of the Chukchi Sea and Beaufort Sea meeting the above definition is one single baseline area. The major stationary source baseline dates and trigger dates for SO_2, NO_2, and PM_{10} for this baseline area are shown below (40 CFR Part 52.21(b)(14)(i)).

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

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application is submitted to EPA after the trigger date. On 31 July 2009, EPA deemed the Shell PSD application for exploratory drilling in the Chukchi Sea complete which effectively, establishes the same minor source baseline dates for SO_2, NO_2, and PM_{10} in the Chukchi Sea/Beaufort Sea baseline area (USEPA 2009a). Consequently, Shell is required to develop an actual emissions inventory to address compliance with air quality increments. However, there are no existing major (or minor) stationary sources in any of the applicable air pollutant significant impact areas and since this is the first application in the baseline area, Shell only needs to address its own emissions.

As discussed in the SB, Shell has estimated emissions from the operation of an oil fired heater in the existing Northern Alaska Intrastate AQCR. The permitting of this source is the responsibility of the Alaska Department of Environmental Conservation since it is not an OCS source. Nevertheless, the minor source baseline dates have been triggered in this AQCR (Schuler, A. 2009). The dates are:

Air Pollutant	Minor Source Baseline Date
Sulfur Dioxide	June 1, 1979
Nitrogen Dioxide	February 8, 1988
Particulate Matter	November 13, 1978

C. Modeling Methodology

To quantitatively evaluate the operating scenarios detailed in Section A, Shell employed the non-guideline ISC3-Prime model (USEPA 2004a). The assumptions, procedures, emission rates, source types, and stack parameters associated with each modeled operating scenario are discussed in the below subsections. Furthermore, to model the majority of the scenarios by air pollutant in a single model run, Shell modified the ISC3-Prime source code to accept at least 1318 emission sources, 20000 receptors points, and 30 source groups (Martin, T. 2009a).

EPA requires verification that the predicted concentrations are not affected by code changes. To accomplish the verification, Shell downloaded the test case files that are available from the EPA SCRAM web site. Shell then ran its modified version of ISC3-Prime using the test case input file. When the EPA test case output file predicted concentrations are compared to the Shell modified model output file predicted concentrations, the results are equivalent out to the third decimal point (Shell 2009a). Thus, the verification is sufficient.

In its review, EPA independently verified the maximum predicted model concentration impacts contained in the Shell supplemental revisions (Shell 2009a) and emails (Winges, K. 2009f and 2009g). EPA downloaded the ISC3-Prime model from the SCRAM web site as well and modified the number of emission sources from 300 to 1500; the number of receptor points from 1200 to 25000; and the number of source groups from six to ten. This EPA version of the model was run for ten cases to obtain final concentration impacts for POS #1, ten cases to obtain final concentration impacts for the ice breaker fleet, one case for PM_{10} maximum predicted concentration impact during Frontier Discoverer bow ice removal, and two cases for $PM_{2.5}$ maximum predicted concentration impacts during bow ice removal and anchor handling. The EPA and Shell modeled SO_2, NO_2, CO, PM_{10} and/or $PM_{2.5}$ concentration impacts differ by at most 0.02 percent. Thus, EPA has independently confirmed that the Shell code changes to ISC3-Prime had no significant affect on project predicted concentration impacts.

C.1 Urban/Rural Area Determination

The exploratory drilling operations will occur at 275 lease blocks contained in Lease Sale Area 193 (Steen, R. 2009c). These lease blocks are located approximately 110-kilometers northwest of the city of Wainwright, Alaska. In addition, Shell will operate a combustion source in a warehouse at a coastal location. Since these operations occur over water and in an area lacking any significant industrial and commercial activities or development, the two areas are considered rural for dispersion modeling purposes (Auer, A. H. 1978).

C.2 Ambient Air Definition

Ambient air is defined as "…that portion of the atmosphere, external to buildings, to which the general public has access" (40 CFR Part 50.1(e). Consistent with this definition, ambient air begins at, and extends outward from the edge of the Frontier Discoverer, and its support vessels. Similarly, ambient air begins at the exterior walls of warehouse that houses the oil fired heater.

C.3 Good Engineering Practice Stack Height

The BPIP-PRIM Program (USEPA 2004b) is used to determine if an exhaust plume from each emission unit will be affected by a nearby structure. Specifically, the stack location, height for each of the ten exhaust stacks above the water surface, and structure height above the water surface, number of tiers, and corner locations for each of the seven structures were input into BPIP-PRIM to make this determination for the Frontier Discoverer. The results from running this EPA program indicate that all proposed stack heights were of insufficient height to prevent wake effects. Hence, Shell included the dimensions associated with the applicable structures that cause wake effects for each stack in its modeling analysis. (Shell 2009a)

Similarly, the warehouse structure and heater stack information were input into BPIP-PRM. It was determined that the warehouse structure would cause wake effects as well

(Steen, R. 2009a). Therefore, Shell included building dimensions in the modeling of this combustion source (Shell 2009a).

C.4 Meteorology

Under the significant impact levels discussion in Section A, Shell could have collected and used site specific meteorology in an EPA refined model to predict less conservative concentration impacts. Instead, Shell chose to use screening meteorology to predict conservative concentration impacts. As a result, the meteorology found in the SCREEN3 model are used in ISC3-PRIME to predict the highest concentration impact for over water and over land modeling cases. In the SCREEN3 model, meteorology consists of 54 hours of wind speed, stability, temperature and mixing height combinations and a single downwind wind direction (USEPA 1992). For use in ISC3-PRIME, an external file was generated with the SCREEN3 meteorology and specific wind directions. Essentially, the file contained the SCREEN3 meteorological data combinations with wind directions incremented every five degrees from five degrees to 360 degrees around the compass. This resulted in 3888 hours of meteorology.

Because the emission units are modeled at their exact location on the Frontier Discoverer relative to a common origin, it was necessary to increment the wind direction every five degrees and use a Cartesian receptor grid as detailed below to predict concentration impacts. If all the emissions units are co-located or forced on a line parallel to a single wind direction, unrealistic high concentrations would be predicted.

The SCREEN3 model employs a default ambient temperature of 293 Kelvin (K) (i.e., 19.85 degrees centigrade or 67.73 degrees Fahrenheit) to predict ambient air quality concentration impacts. A more representative ambient temperature of 261.1 K (i.e., -12.1 degrees centigrade or 10.31 degrees Fahrenheit) measured at Barrow, Alaska was selected by Shell to represent conditions in the Chukchi Sea. (Shell 2009c)

C.5 Receptor Locations and Elevations

A Cartesian coordinate system was used by Shell to define its primary rectangular modeling domain and engulf all its over water drilling operations (see Figure 1). The center of the 13-kilometer by 10-kilometer domain is the exploratory drill hole location below an anchored Frontier Discoverer. As shown in Figure 2, the drill hole location is at (93, 55) meters. Receptors in this domain are spaced every 100-meters for a total of 12576 points.

There are several domains within and extending out from the primary domain.

- The first domain consists of receptor points around the hull of the Frontier Discoverer. These points define ambient air for the Frontier Discoverer which are spaced every ten meters. Total receptor points: 34.

- The second domain extends from the hull edge of the Frontier Discoverer out to a distance of about 500-meters. Receptor points in this domain are at 25-meter intervals. Total receptor points: 1672.

- Starting at the stern of the Frontier Discoverer are the elongated third and fourth domains of approximately 50000-meters by 30-meters. From the stern and extending in a negative X-direction to a distance of 8000-meters and from 8000-meters to 50000-meters, the receptor points are at 25-meter and 100-meter intervals, respectively. Y-direction receptors span the width of the Frontier Discoverer and are located at 0-meters and ±15-meters from the centerline of the vessel. Total receptor points: 2232.

- During replenishment, the supply ship is tied to the Frontier Discoverer. As a result, a fifth domain consists of receptor points placed around the supply ship hull at about 10-meter intervals. Total receptor points: 18.

A discrete receptor point is used to predict concentration impacts at two over land locations. They are Point Lay and Wainwright which are 100-kilometers and 110-kilometers, respectively, from the Shell drilling operations. (Shell 2009b)

The over water domains plus the two over land discrete receptors result in a total of 16534 receptor points, all with a surface elevation set to 0.0-meters. Except for POS #2, these receptor points and elevations are input into ISC3-Prime to quantify the maximum concentration impacts for POS #1 and SOS's #1 to #6.

For the over land combustion source, Shell also uses a Cartesian coordinate system. Receptor points are spaced at 10-meter intervals and located at the exterior walls of the building housing the combustion unit. Extending outward from the building to 1000-meters, receptor points are spaced at 25-meter increments. All receptor point elevations are set to 0.0-meters. Total receptor points: 6592.

C.6 Volume Source Representation For Vessels

Because there are no established procedures to model underway ship emissions, the vessels were modeled as volume sources with the release height based on the lowest final plume rise in each fleet. EPA believes this approach will result in conservative concentration predictions.

To obtain the lowest final plume rise, EPA requested Shell to model each known possible vessel of the ice breaker and oil spill response fleets, and the supply ship as point sources taking into account building wake effects. EPA also recommended that D stability and a wind speed of 20 meters per second meteorology be used in the SCREEN3 model to reduce the plume rise. The lowest plume rise calculated by SCREEN3 within the ice breaker fleet and oil spill response fleet, and the supply vessel would establish the release height of each representative volume source.

Initial lateral and vertical dispersion characteristics are also required when modeling volume sources. Following the guidance contained in the ISC3 model user's guide (USEPA 1995), the initial lateral and vertical dispersion characteristics are based on the length of the vessel (sigma-y_o) and the height dimension of the source (sigma-z_o), respectively.

The calculated volume source parameters representing the ice breaker fleet, oil spill response fleet and supply ship were subsequently modeled concurrently with the Frontier Discoverer on board emission units as they operate in the Chukchi Sea (Shell 2009b).

C.7 Source Emission Rates and Stack Parameters and Locations

The following two subsections detail the calculated emission rates of each air pollutant and the source parameters of each combustion unit or source that were input into ISC3-Prime to determine compliance with NAAQS and air quality increments.

C.7.a Emission Rates

The exploratory drilling consists principally of a drill ship, two fleets, and a supply ship. A list of the emission units or sources and the modeled air pollutant emission rates are presented in three tables. Table 3 shows the short term emission rates for POS #1 and POS #2. Table 4 details the long term emission rates for POS #1. Table 5 lists the emission rates for the SOS's. In each of the tables, EPA calculated emission rates are compared to the Shell emission rates that appear in the ISC3-Prime model input files. Differences in the calculated values can be attributed, in part, to round off, number of significant digits carried forward in each calculation, and the calculation sequence. If Shell chose to use a more conservative emission rate, EPA did not contest the number (i.e., Table 3, CO emission rate for cementing engine).

The vessels that are modeled as volume sources include the replenishment ship, the oil spill response vessel, the oil spill response work boat (3), ice breaker #1, and ice breaker #2. The total hourly emission rates for these volume sources appear in the three tables. However, it is the individual volume source hourly emission rate that is actually input into ISC3-Prime model.

To derive the individual volume source emission rate, the vessel travel distance (i.e., line of adjacent volume sources) is divided by the separation distance between the sources to obtain the number of volume sources. The total air pollutant emission rate for vessels appearing in Tables 3, 4 and 5 are then divided by the number of volume sources to derive a common air pollutant emission rate for each individual volume source. For example, suppose the travel distance of Ice Breaker #2 is 4800-meters and the separation distance is 100-meters. Dividing the travel distance by the separation distance results in 48 volume sources on the line. Using the SO_2 emission rate (41.6 pounds per hour) that appears in Table 3 for Ice Breaker #2 and dividing it by 48 volume sources, an individual volume source emission rate of 0.8666 pounds per hour is calculated.

In addition, Ice Breaker #2 is used in SOS #1, #5 and #6 to remove ice that has accumulated on the bow of the Frontier Discoverer and for anchor deployment and retrieval. See Figure 3 and Figure 4. For these three other uses of Ice Breaker #2, the emission rates have been partitioned according to the vessel's primary and secondary uses during a day. It is expected to take one hour for bow ice removal and 18 hours to deploy and retrieve the anchors. When Ice Breaker #2 is not performing these tasks, it is assumed to be breaking or crushing ice in the Chukchi Sea.

Detailed discussions of the assumptions and methodologies used to derive these modeled emission rates can be found in Section 3 and Appendix A of the SB.

C.7.b Source Locations and Source Parameters

The location and source parameters of the emission units and sources appear in Table 6 and Table 7 for the POS's and SOS's, respectively. The X-coordinate and Y-coordinates are based on an origin at (93, 55) meters as depicted in Figure 2. In general, Ice Breaker #1 and Ice Breaker #2 will operate no closer than 4800-meters and 1000-meters upwind of the Frontier Discoverer respectively, during drilling operations. During the removal of ice that has accumulated on the bow of the Frontier Discoverer, Ice Breaker #2, can approach no closer than 100-meter from the drill ship (see Figure 3). The oil spill response fleet will operate downwind of the Frontier Discoverer at a distance of 2000-meters.

Parameters 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.

C.8 Scaling Factors

Scaling factors as recommended by EPA (1992) are applied to the hourly concentrations predicted by ISC3-Prime to obtain the appropriate period concentration. The scaling factors are the upper range numbers and are shown below. In this analysis, EPA recommended that Shell use the upper end scaling factors because of the expected wind persistence over the Chukchi Sea and the wake effects caused by vessel structures.

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

D. Representative Background Air Quality

After much discussion, EPA agreed with Conoco-Phillips Alaska, Inc (CPAI) that are no islands, platforms or infrastructure in the Chukchi Sea to install, operate and maintain ambient air quality monitoring equipment. As a solution, EPA and CPAI decided that collecting air pollutant concentration data at Wainwright, AK (see Figure 5) is a workable alternative and that the data could be used to represent to background levels out in the Chukchi Sea, seaward of the OCS (i.e., 28-mile from the AK shoreline). Wainwright is a rural area with a few combustion sources while the Chukchi Sea has no combustion sources.

The monitoring station was installed near the Wainwright airport and data collection began in 08 November 2008. Data measurements included SO_2, NO_2, NO_x, NO, CO, PM_{10}, $PM_{2.5}$ and O_3. Meteorological data collected at the Wainwright airport will be used in any necessary evaluation of the air quality data in lieu of collecting site specific data. EPA approved the 23 December 2008 monitoring plan (CPAI 2008) on 05 January 2009.

Shell subsequently teamed with CPAI so that they can use the data from the Wainwright monitoring station in their Chukchi Sea PSD application ambient air quality analyses. EPA conveyed to Shell that the minimum four months of air quality data as provided in 40 CFR Part 52.21(m)(1)(iv) would be acceptable provided the shorter period measurements would be as conservative as what would be expected in a twelve month collection for all pollutants.

EPA reviewed the monthly and quarterly reports including instrument operating parameters and analyzed the measured air pollutant data during the collection period from 08 November 2009 to 30 June 2009 (CPAI 2009a, 2009b, 2009c, and 2009d) for consistency with the PSD regulation and the approved monitoring plan. The conclusions reached by EPA (2009a) after the review and analysis are:

- The SO_2, NO_2, NO_x, NO, CO, and O_3 gaseous measurements collected from 08 November 2008 to 30 June 2009 are acceptable for use as representative background air quality levels. Total months of data: ~8 months.

- The PM_{10} measurements collected from 08 November 2008 to 30 June 2009 are acceptable for use as representative background air quality levels. Total months of data: ~8 months.

- The $PM_{2.5}$ measurements collected from 08 November 2008 to 05 March 2009 are unacceptable because the recorded flow rates were outside of its operating range and varied significantly, there were numerous recorded negative hourly concentrations, and the sampler did not pass a calibration audit. This period of $PM_{2.5}$ data should not be used to represent background air quality levels in an ambient air quality impact analysis.

- The $PM_{2.5}$ measurements collected from 06 March 2009 to 30 June 2009 have met the conditions contained in the monitoring plan (CPAI 2008). In order to fully comply with 40 CFR Part 51.21(m)(3) which requires the monitoring station to operate according to the quality assurance requirements contained Appendix A of 40 CFR Part 58, Shell is currently working to install a collocated monitor as part of the North Slope network. This quality assurance check will rely on a Federal Reference Method (FRM) $PM_{2.5}$ sampler located next to a Federal Equivalent Method (FEM) $PM_{2.5}$ sampler. Total months of data: ~4 months.

- The air pollutants collected during each period of record met the 80% data recovery rate required by EPA guidance (USEPA 1987).

- Depending upon the air pollutant, from one to three months of data fell inside the Shell drilling season (i.e, November, December and June).

Shell provided a demonstration that the data collection period of at least four (4) months is representative of a twelve (12) data collection program. In its demonstration, Shell compared quarterly average maximum 3-hour SO_2 concentrations, average maximum 24-hour SO_2 concentrations, average monthly NO_2 concentrations measured at BPX-Badama, BPX-Liberty, BPX-Prudhoe Bay (Pad A), BPX-Prudhoe Bay (CCP), and CPAI-Alpine (Nuiqsut). For CO, the demonstration is based on a hourly times series of measurements at BPX-Liberty. See Figure 5. (Shell 2009b).

The SO_2 and NO_2 measurements at the five stations were generally higher during the first and fourth quarters while the CO measurements at BPX-Liberty were higher during the first and second quarters. The partial fourth quarter, and the first and second quarters measurements at Wainwright tend to show a similar pattern for these three gaseous air pollutants. As a result, EPA believes that the highest SO_2, NO_2, and CO measurements at Wainwright have been captured and are acceptable as representative background levels.

PM_{10} measurements at BPX-Badami were compared to the measurements at Wainwright for the same period. No pattern could be developed because the 24-hour measured concentrations at Wainwright during the months of May and June, 2009 were 45 micrograms per cubic meter and 66 micrograms per cubic meter, respectively. In general, the measured PM_{10} 24-hour concentrations at BPX-Badami were less than 12.5 micrograms per cubic. (Shell 2009b) Hence, EPA believes that the use of the Wainwright measured PM_{10} concentration data would provide a conservative background level for the Chukchi Sea.

The monitoring station at Wainwright is the first site with a $PM_{2.5}$ sampler in the North Slope. EPA believes that $PM_{2.5}$ measurements at Wainwright would be low because of the lack of significant stationary combustion sources in the area. Also, EPA believes that the data collected at Wainwright is representative of the area seaward of the OCS in the Chukchi Sea because there are no anthropogenic sources in the area.

Table 8 presents air quality measurements at Wainwright.

E. Air Quality Modeling Results

This section provides the ISC3-Prime modeling results used to demonstrate compliance with the PSD regulation including NAAQS and air quality increments as described in Section A. Modeling results are compared with preconstruction modeling thresholds, significant impact levels, NAAQS and air quality increments. In addition, a qualitative discussion is provided for O_3.

E.1 Preconstruction Ambient Monitoring Threshold

As shown in Table 9, preconstruction monitoring is required for SO_2, NO_2, and PM_{10} because the predicted highest concentration for these three air pollutants emitted by the Frontier Discoverer and the two fleets exceed their significant monitoring threshold. Preconstruction monitoring is also required for O_3 because NO_2 and VOC emitted by the Frontier Discoverer and the two fleets exceed 100 tons per year (see SB).

To satisfy the preconstruction monitoring requirement, CPAI and Shell are jointly operating and maintaining an air quality monitoring station at Wainwright, Alaska. See Section D.

E.2 Significant Impact Levels

The predicted highest concentration impact for the applicable averaging time exceeds the significant impact levels for SO_2, NO_2, and PM_{10} (see Table 10). As a result, a detailed ambient air quality impact analysis is required for these three air pollutants. An air quality analysis is also required for O_3 because NO_2 and VOC emissions exceed 100 tons per year.

Also shown in the table are the significant impact area radii for the air pollutants that exceed the threshold. The 24-hour SO_2 and PM_{10}, and annual NO2 significant impact area radius was set to 50-kilometers because the model predictions had not fallen below the threshold for these three air pollutants at this distance.

Even though SO_2, NO_2, and PM_{10} predicted concentrations exceed their significant impact levels, Shell does not need to develop an allowable and actual emissions inventory of other sources to address compliance with NAAQS and air quality increments because there are no existing major (or minor) stationary sources in any of the applicable air pollutant significant impact areas and this is the first application in the AQCR (see Section B). Shell therefore, only needs to address its own emissions in the analyses.

E.3 National Ambient Air Quality Standards

Table 11 and Tables 12a to 12c present the predicted concentration impacts for POS #1 and SOS #1 to #6, respectively. In addition Table 13 shows the predicted concentration impacts from POS #1 at Point Lay and Wainwright, the two nearest villages to the Lease Sale Area 193. The total concentration impact (predicted project impact plus the background measurement discussed in Section D) for the applicable air pollutants and averaging times are expected to less than the NAAQS.

For SOS #1, #2, #5 and #6, only $PM_{2.5}$ concentrations were predicted because the total concentration impacts from POS #1 approaches the NAAQS. The other air pollutant total concentration impacts under POS #1 are well below the NAAQS.

E.4 Air Quality Increments

Table 14 and Table 15 show a comparison of the model predicted highest concentration impacts for POS #1 to the Class II area air quality increments. Similarly, concurrent operations of POS #1 with SOS #1 to SOS #4, and the independent operations of SOS #5 and SOS #6 predicted concentrations to Class II area air quality increments are presented in Table 16. All primary and secondary operating scenario predicted concentrations are less than the Class II area air quality increments.

The nearest Class I area is Denali National Park located about 950-kilometers from the Shell lease blocks in Lease Sale Area 193. Based on the distance and the amount of emissions, the NPS did not request Class I area quality increment analysis for Denali National Park (Notar 2009a).

E.5 Ozone

Because NO_x and VOC net emissions exceed 100 tons per year, Shell is required under the PSD regulation to perform an O_3 ambient air quality impact analysis including gathering ambient air measurements. EPA has determined that a qualitative analysis is adequate from Shell because there is no single source model for O_3 and it is not reasonable to run an air shed model.

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.

Over the past ten years, there have been monitoring programs that measured O_3 and O_3 precursors (i.e., NO_x and VOC) in the North Slope where there are oil and gas operations. The O_3 measurement programs include Barrow (2003 - 2005), BPX-Badami (1999), BPX-Prudhoe Bay (2006 - 2007), 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 while the highest 8-hour measurement was 50 parts per billion. The hourly concentration represents 61 percent of the 120 parts per billion hourly NAAQS. The 8-hour concentration represents 67 percent of the 75 parts per billion of the 2008 8-hour NAAQS (see Table 2). (Shell 2009b).

As discussed in Section D, CPAI and Shell began an ambient air quality data collection program at Wainwright, Alaska to represent background air quality levels in the Chukchi Sea. Table 8 provided a summary of the O_3 hourly and 8-hour measurements during the first eight months of data collection at Wainwright. The 1-hour and 8-hour measured concentrations represent 48 percent and 65 percent of their NAAQS, respectively.

Unlike the North Slope, there are no stationary sources located seaward of the OCS in the Chukchi Sea. Shell expects to emit approximately 1965 tons per year of NO_x and roughly 166 tons per year of VOC O_3 precursor emissions. These precursor emissions and their contribution to the formation of O_3 is expected to be small downwind of Lease Sale Area 193.

F. Additional Impacts Analysis

An additional impacts analyses was completed pursuant to paragraph (o) in 40 CFR Part 52.21 and the guidance contained in the draft New Source Review Workshop Manual (USEPA 1990). The following subsections describe the three analyses - growth, soils and vegetation, and visibility.

F.1 Growth

Growth will likely occur in the Chukchi Sea during the drilling season when Shell conducts exploratory drilling operations. Emissions increases and air quality concentration impacts were described and presented in the SB and Section E. No other type of growth (i.e., industrial, commercial or residential growth) is expected in the Chukchi Sea.

Some growth and support facilities are expected at several possible coastal locations to support the project. The location of the growth and facilities could occur at Wainwright, Barrow, Deadhorse and Kotzebue. Support facilities include storage facilities and aircraft hangers. Rotating work crews could lodge at local hotels and trailer camps while helicopters will be used to transport work crews to and from the Frontier Discoverer. (Shell 2009b).

A warehouse may be constructed at either Wainwright or Barrow. The warehouse will be heated by natural gas or heating oil. The emissions calculations associated with heating the warehouse have been based on oil firing and were presented in Table 3 and described in Section C. Table 17 and Table 18 details the concentration impacts associated with the operation of the heater. The total concentration impact of the heater is not expected to exceed any NAAQS or Class II area air quality increments.

This shore based facility is not considered an OCS source requiring an air permit under 40 CFR Part 55.2 and any necessary air permit will be issued by the State of Alaska.

The Helicopter Discoverer will be utilized to rotate the work crews. A maximum of three trips per day are expected. The emissions associated with take off and landings are discussed in the SB. Air quality modeling was not performed for the take off and landings because of the significant dispersion that occur as a result of the helicopter horizontal rotors. (Steen, R. 2009b)

F.2 Soils and Vegetation

Under 40 CFR Part 52.21, Shell must provide an analysis of the project air pollutant concentration impacts on soils and vegetation within each applicable air pollutant significant impact area. However, the impacts are not limited to terrestrial locations. If the significant impact area is a body of water (e.g., the Chukchi Sea), impacts could affect aquatic vegetation and sediment. It is also plausible that the significant impact area could include a terrestrial location and a body of water. In this application, only impacts to aquatic vegetation and sediment are evaluated because the area within the largest possible significant impact area radius of 50-kilometers centered on the Frontier Discoverer is ocean (see Figure 6). The nearest terrestrial location is approximately 100-kilometers from the Lease Sale Area 193.

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 (Martin, T. 2009b). Their efforts did not reveal any aquatic vegetation or sediment having commercial or recreational value in the significant impact areas that are expected to be negatively impacted by the Shell drilling operations in the Chukchi Sea.

F.3 Class II Area Visibility

The NPS identified two Class II national monuments as areas of concern (Notar 2009b). The two areas are the Cape Krusenstern National Monument and the Bering Land Bridge National Monument shown in Figure 7. The distance from the nearest Shell lease block to Cape Krusenstern National Monument and the Bering Land Bridge National Monument is 280-kilometers and 410-kilometers, respectively. Based on the separation distances, the NPS believes that the Shell project should not adversely affect visibility at the two national monuments (Notar 2009a).

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 degrees Fahrenheit (Martin, T. 2009b).

Shell estimates the water vapor emissions to be 57 tons per day from the Frontier Discoverer (Martin, T. 2009b). EPA estimates the water vapor emissions to be 67 ton per day from the Frontier Discoverer and 395 tons per day from all combustion sources. Regardless, the water vapor emissions may contribute to fog formation depending on atmospheric conditions.

A visible exhaust plume is expected from the Frontier Discoverer, oil spill response and ice breaker fleets, and supply ship during exploratory drilling activities. However, because of its location in the Chukchi Sea, visibility impairment is not expected to be of concern.

G. Air Quality Related Values Including Visibility

The Federal Land Managers are responsible for the management of mandatory federal Class I areas including the protection of air quality related values (AQRVs) under 40 CFR 52.21(p). The AQRV include sulfate and nitrate deposition and visibility impairment. The nearest Class I areas to Lease Sale Area 193 are the NPS Denali National Park and the FWS Bering Sea Wilderness Area located approximately 950-kilometers southeast and 1100-kilometers south of the Shell proposed drilling locations in the Chukchi Sea. At this distance, the NPS and FWS are not expecting significant sulfate and nitrate deposition, or visibility impairment impacts at these two mandatory Federal Class I areas (Notar 2009a).

H. Conclusions and Recommendations

An ambient air quality impact analysis was performed using conservative modeling assumptions to demonstrate compliance with NAAQS and air quality increments at over water and over land locations. These assumptions include the use of screening meteorology and the upper end scaling factors to derive other averaging period concentrations from the 1-hour model prediction, and the use of a volume source height

Exhibit 8
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based on a D stability and 20 meter per second wind speed. From an engineering perspective, the modeling analysis also took into consideration the application of emission limits and the requirements reflecting Best Available Control Technology, and other limits in the permit that restrict operation and location of the Frontier Discoverer, ice breaker fleet, oil spill response fleet and/or supply vessel. See SB for operating permit limits or restrictions.

Based on the conservative modeling assumptions, Wainwright air pollutant measurements, and the predicted SO_2, NO_2, CO, and PM_{10} concentration impacts for the primary and secondary operating scenarios, EPA has concluded that the Shell project is expected to comply with the applicable NAAQS and/or Class II area air quality increments for these four air pollutants. Using the $PM_{2.5}$ measurements presented in Table 8 that satisfied the approved monitoring plan, the total $PM_{2.5}$ concentration impacts did not violate the NAAQS. The additional impacts analysis, and the O_3 and Class I area analyses also adequate with respect to complying with the PSD requirements.

In terms of fulfilling Appendix A in 40 CFR Part 58, a permit condition is recommended that would require Shell to install, operate and maintain collocated FEM $PM_{2.5}$ and FRM $PM_{2.5}$ samplers at a site consistent with PSD requirements.

With respect to the non-guideline model, the notice informing the public of the issuance of a draft permit should include solicitation for comments on the use of the ISC3-Prime model in the ambient air quality impact analysis.

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Figure 1
Modeling Domain and Receptor Points

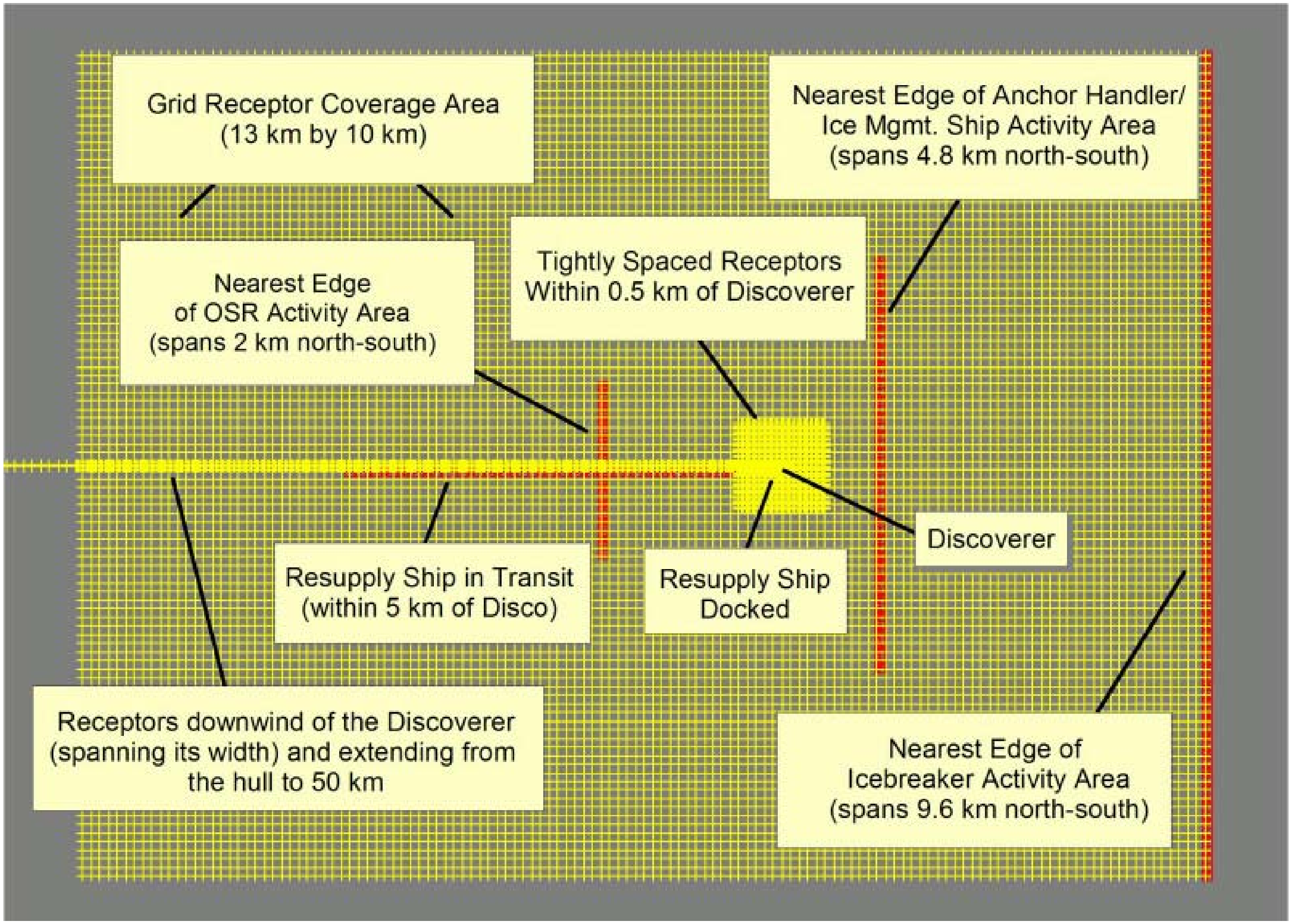

Figure 2
Frontier Discoverer and Onboard Emission Units

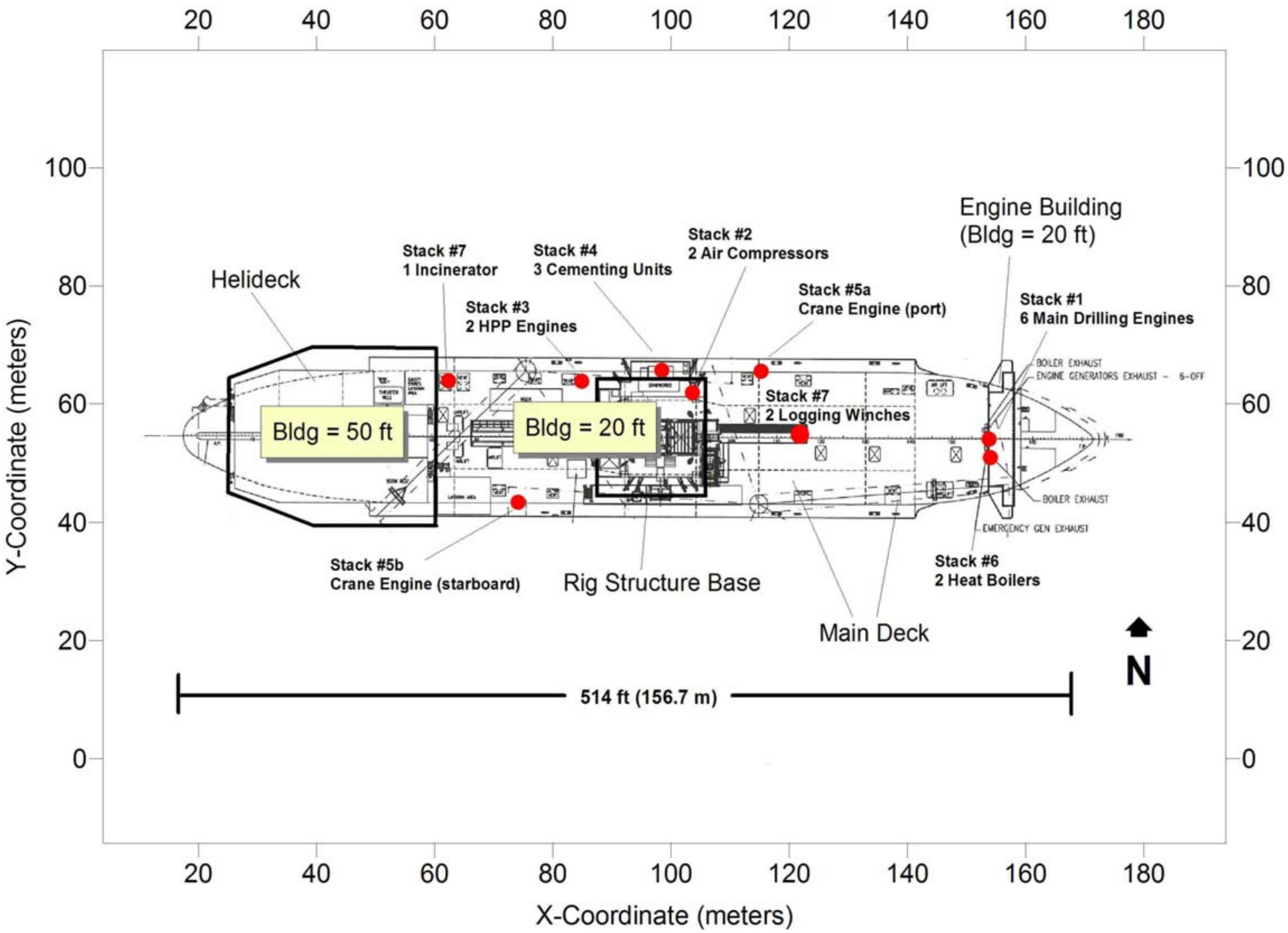

Figure 3
Bow Ice Washing of Frontier Discoverer Layout

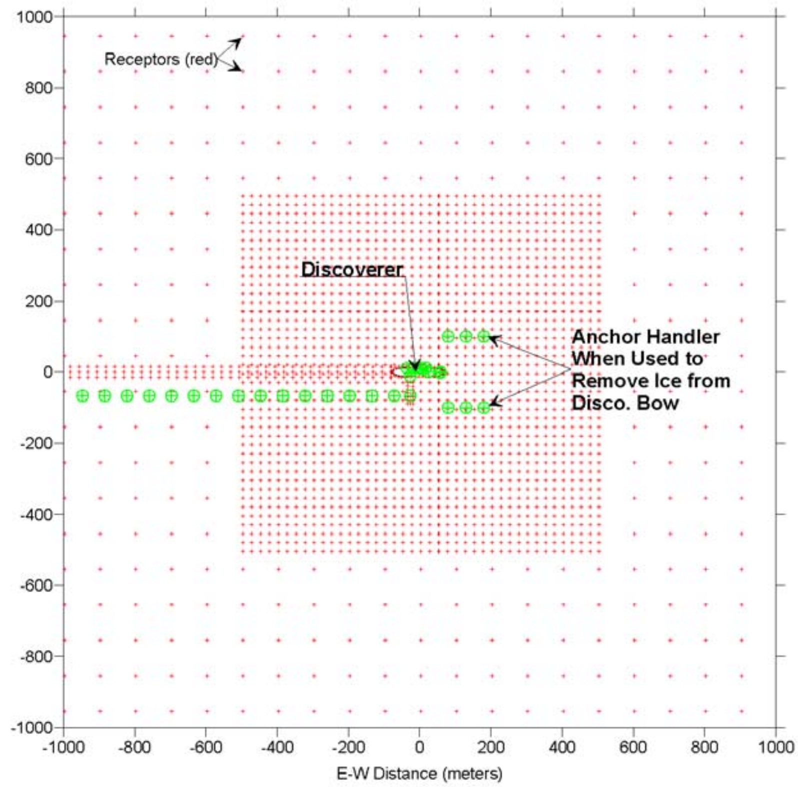

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Figure 4
Anchor Handling Layout

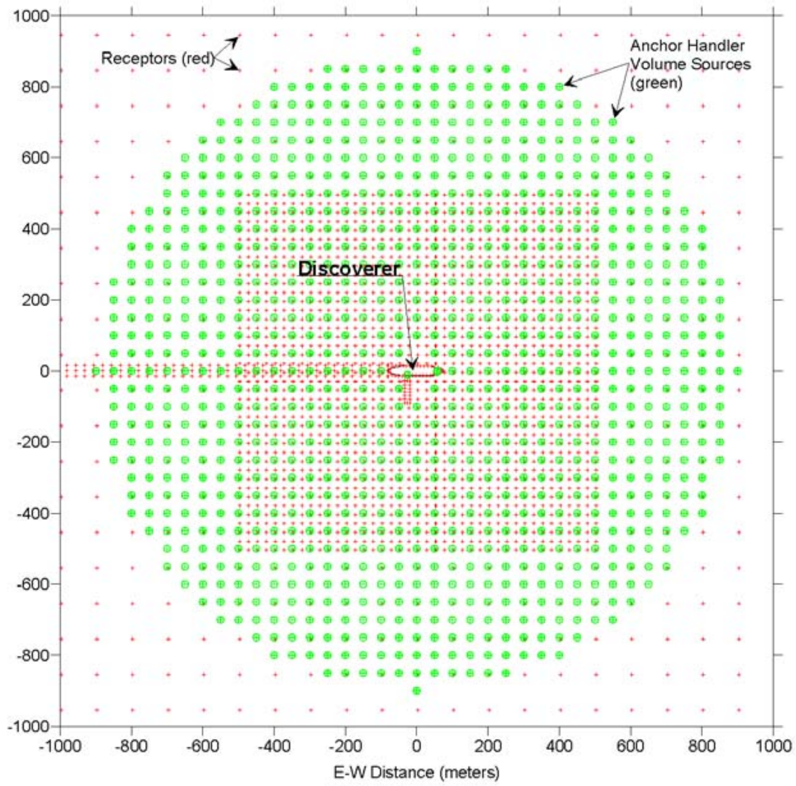

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Figure 5
North Slope Monitoring Stations

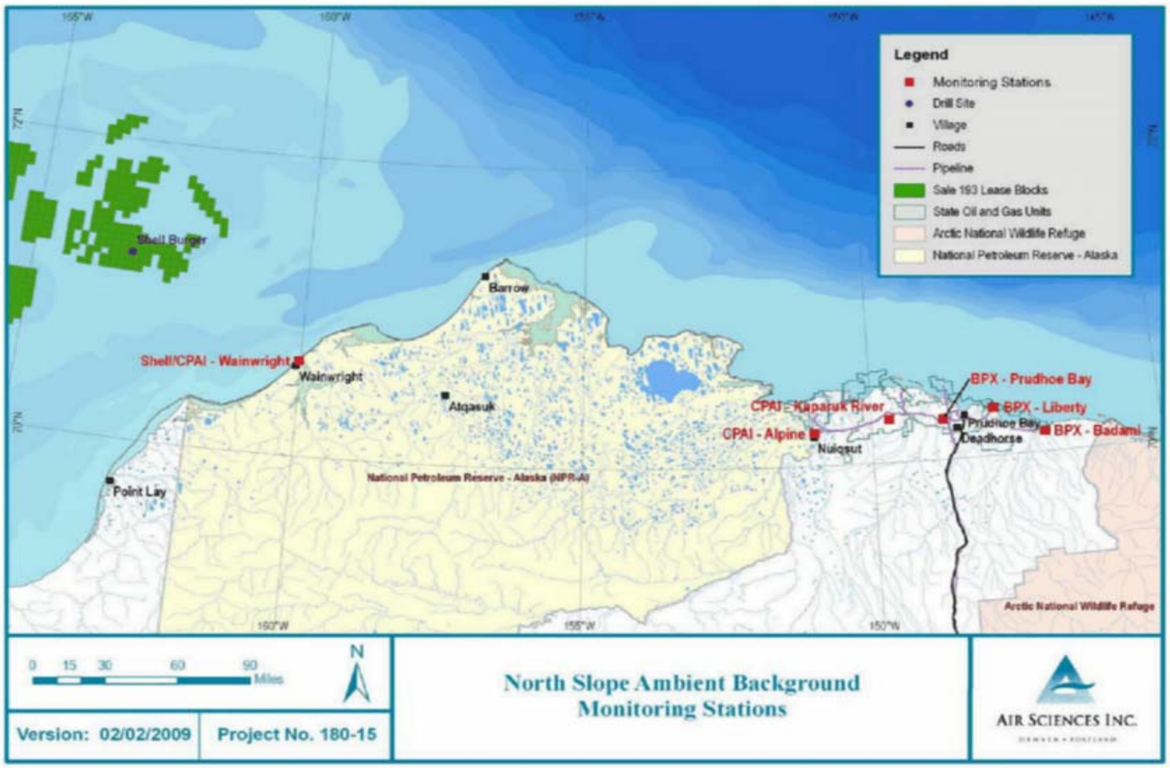

Exhibit 8
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Figure 6
Chukchi Sea OCS Leases and Significant Impact Areas

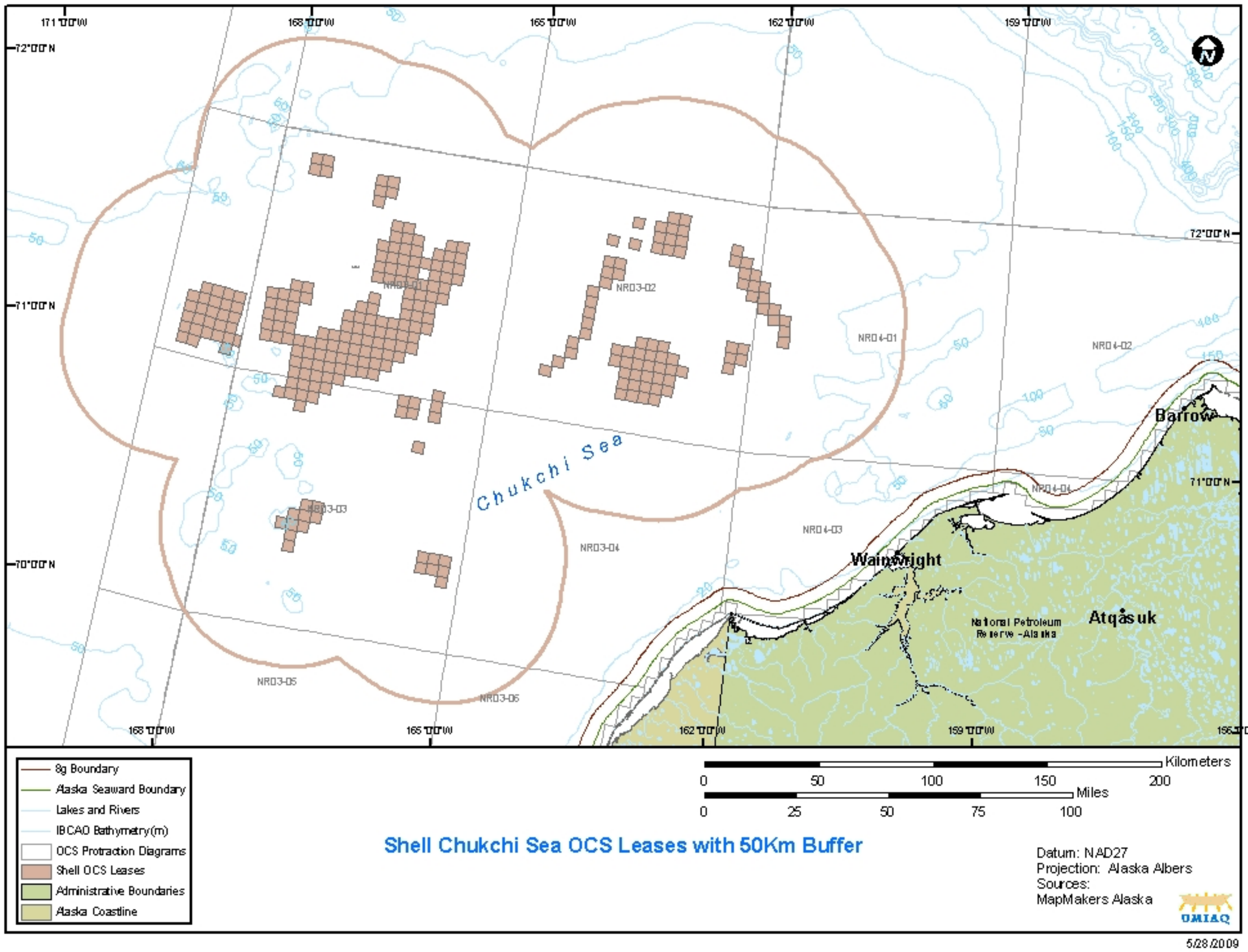

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Figure 7
Location Map of Class II Area National Monuments

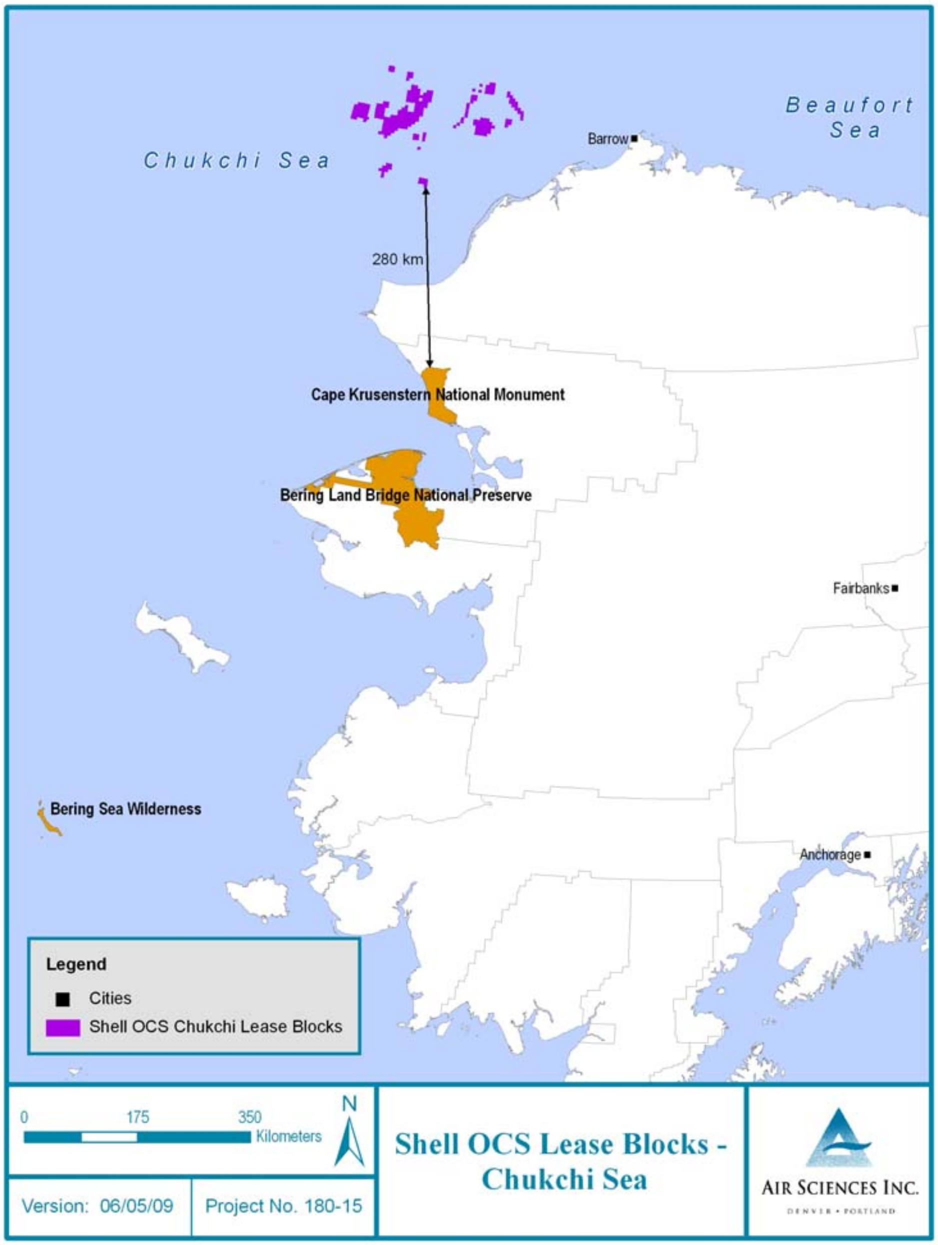

Exhibit 8
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Table 1
Primary and Secondary Operating Scenarios

Operating Scenario	No.	Description
Primary	1	Drilling by the Frontier Discoverer, and deployment of the ice breaker and oil spill response fleets.
	2	Associated Growth (land based combustion source)
Secondary	1	Frontier Discoverer bow ice removal by Ice Breaker #2 concurrent with POS #1.
	2	Supply ship transit concurrent with POS #1.
	3	Frontier Discoverer replenishment by supply ship concurrent with POS #1.
	4	Frontier Discoverer emergency generator testing concurrent with POS #1.
	5	Anchor deployment by Ice Breaker #2 and no drilling activities.
	6	Anchor retrieval by Ice Breaker #2 and no drilling activities.
	7	Frontier Discoverer alignment concurrent with POS #1.
	8	Helicopter support concurrent with POS #1.
	9	Multi year ice breaking concurrent with POS #1.
	10	No ice breaking concurrent with POS #1.
	11	No replenishment concurrent with POS #1.

Reference: Shell 2009a, 2009b and 2008

POS ≡ Primary Operating Scenario

Table 2

Ambient Air Quality Standards, Air Quality Increments, and Impact Area and Monitoring Thresholds

Air Pollutant	Averaging Period	Air Quality Standards [a] Primary ($\mu g/m^3$)	Air Quality Standards [a] Secondary ($\mu g/m^3$)	Air Quality Increments [b] Class I Area ($\mu g/m^3$)	Air Quality Increments [b] Class II Area ($\mu g/m^3$)	Significant Impact [c] ($\mu g/m^3$)	Ambient Monitoring [b] ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	3-Hour		1300	25	512	25	
	24-Hour	365		5	91	5	13
	Annual	80		2	20	1	
Nitrogen Dioxide (NO_2)	Annual	100	100	2.5	25	1	14
Carbon Monoxide (CO)	1-Hour	40000				2000	
	8-Hour	10000				500	575
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	150	150	8	30	5	10
	Annual			4	17	1	
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				0.1
Ozone (O_3)	1-Hour	0.12 [d]	0.12 [d]				[e]
	8-Hour [f]	0.75 [d]	0.75 [d]				
	8-Hour [g]	0.80 [d]	0.80 [d]				
Fluorides	24-Hour						0.25
Total Reduced Sulfur	1-Hour						10

Exhibit 8

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Air Pollutant	Averaging Period	Air Quality Standards [a] Primary (µg/m^3)	Air Quality Standards [a] Secondary (µg/m^3)	Air Quality Increments [b] Class I Area (µg/m^3)	Air Quality Increments [b] Class II Area (µg/m^3)	Significant Impact [c] (µg/m^3)	Ambient Monitoring [b] (µg/m^3)
Hydrogen Sulfide (H_2S)	1-Hour						0.2
Reduced Sulfur Compounds	1-Hour						10

a. Reference: 40 CFR Part 50
b. Reference: 40 CFR Part 52.21(c)
c Reference: EPA 1990 and 1987
d. Units in parts per million (ppm).
e. No monitoring threshold level. However, if the net emissions increase of oxides of nitrogen (i.e., NO_2) or volatile organic compound (VOC) are 100 tons per year or more, the PSD regulation requires an ambient air quality impact analysis including an ozone data collection program. 40 CFR Part 52.21(i)(5)
f. 2008 Standard
g. 1997 standard

Table 3
Primary Operating Scenario - EPA Calculated vs Shell Modeled Short Term Emission Rates

Emission Units or Sources	Total Emission Rate [a]									
	SO_2		NO_2		CO		PM_{10}		$PM_{2.5}$	
	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)
Generator Engine [b,c]	0.0660	0.0667	4.6200	4.6881	1.6800	2.2548	1.2000	1.1881	1.2000	1.1881
MLC Comp Engine [b,d]	0.0171	0.0171	10.6500	10.6611	9.3300	9.3286	0.5400	0.5333	0.5400	0.5333
HPU Engine [b,e]	0.0062	0.0062	10.8200	10.8135	0.3210	0.3294	0.2100	0.2079	0.2000	0.2079
Port Crane Engine [b,f]	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Stbd Crane Engine [b,f]	0.0088	0.0088	12.2000	12.3937	0.2600	0.2619	0.0800	0.0857	0.0800	0.0857
Cementing Engine [b,g]	0.0102	0.0102	6.3300	6.3325	0.6500	1.1794	0.1550	0.1556	0.1550	0.1556
Log Winch Engine [b,h]	0.0021	0.0021	[h]	0.0000	0.2200	0.2286	[h]	0.0000	[h]	0.0000
Heat Boiler [b,i]	0.0254	0.0254	3.2000	3.2079	1.2200	1.2333	0.3800	0.3746	0.3800	0.3746
Incinerator [b,j]	0.3500	0.3454	0.1589	0.1587	4.2800	4.2778	0.2605	0.2603	0.2224	0.2222
Ice Breaker #1 [k]	41.6100	41.6000	1107.8100	1108.6476	171.2300	171.2762	48.0000	48.0000	42.2000	42.2095
Ice Breaker #2 [l]	41.6100	41.6000	1125.5800	1108.6476	171.3200	171.3143	48.0000	48.0381	42.2000	42.2095
Oil Spill ResponseK [m]	2.6000	2.5965	19.5400	19.5556	0.8600	0.8546	0.3900	0.3838	0.3900	0.3838
Oil Spill ResponseN [n]	11.0400	11.0476	84.1905	84.2540	39.3900	39.3968	5.2700	5.2698	4.2060	4.1905
Over Land Heater [o,p]		0.6675		1.0508		0.2627		0.1738		0.1738

Reference: See Statement of Basis and Appendix A for detailed discussion of emission rates.

a. The reason for differences between EPA and Shell calculated emission rates can be attributed in part, to rounding off, number of significant digits carried forward in each calculation, and the calculation sequence.
b. Emission units on the Frontier Discoverer.
c. Emission rate of six generator engines, FD 1-6.

d. Emission rate of three MLC compressor engines, FD 9-11.
e. Emission rate of two HPU engines, FD 12 and13.
f. Emission rate of the port and starboard cranes, FD 14 and 15. For modeling purposes, the emissions have been assumed to be exhausting from the starboard crane engine stack.
g. Emission rate of three cementing engines, FD 16-18. Shell used a more conservative emission factor to derive the CO emission rate.
h. Emission rate of two logging winch engines, FD 19 and 20. For modeling purposes, the NO_2, PM_{10} and $PM_{2\ 5}$ emissions have been assumed to be exhausting from the cementing engine stack.
i. Emission rate of two heat boilers, FD 21 and 22.
j. Emission rate of one incinerator, FD 23.
k. Ice Breaker #1 emission rates represent the sum total of 96 volume sources.
l. Ice Breaker #2 emission rates represent the sum total of 48 volume sources.
m. Oil Spill ResponseK emission rates represent the sum total of 40 volume sources (i.e., three work boats).
n. Oil Spill ResponseN emission rates represent the sum total of 40 volume sources.
o. Shell has not decided the over land location of the heater and warehouse.
p. POS #2.

Table 4
Primary Operating Scenario - EPA Calculated vs Shell Modeled Long Term Emission Rates

Emission Units or Sources	Total Emission Rate [a]									
	SO_2		NO_2		CO		PM_{10}		$PM_{2.5}$	
	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)
Generator Engine [b,c]	0.0660	0.0667	d	d	d	d	d	d	d	d
MLC Comp Engine [b,e]	0.0171	0.0171	d	d	d	d	d	d	d	d
HPU Engine [b,f]	0.0062	0.0062	d	d	d	d	d	d	d	d
Port Crane Engine [b,g]	0.0000	0.0000	d	d	d	d	d	d	d	d
Stbd Crane Engine [b,g]	0.0088	0.0088	d	d	d	d	d	d	d	d
Cementing Engine [b,h]	0.0102	0.0102	d	d	d	d	d	d	d	d
Log Winch Engine [b,i,j]	0.0000	0.0000	d	d	d	d	d	d	d	d
Heat Boiler [b,k]	0.0254	0.0254	d	d	d	d	d	d	d	d
Incinerator [b,j,l]	0.0794	0.0794	d	d	d	d	d	d	d	d
Ice Breaker #1 [m]	41.6000	41.6000	d	d	d	d	d	d	d	d
Ice Breaker #2 [n]	41.6000	41.6000	d	d	d	d	d	d	d	d
Oil Spill ResponseK [o]	2.6000	2.5965	d	d	d	d	d	d	d	d
Oil Spill ResponseN [p,j]	3.8651	3.8730	d	d	d	d	d	d	d	d

Source: See Statement of Basis and Appendix A for detailed discussion of emission rates.

a. The reason for differences between EPA and Shell calculated emission rates can be attributed in part, to rounding off, number of significant digits carried forward in each calculation, and the calculation sequence.
b. Emission units on the Frontier Discoverer.
c. Emission rate of six (6) generator engines, FD 1-6.
d. Short term emission rate was used to predict long term NO_2 and $PM_{2.5}$ concentrations. Long term concentrations were not predicted for CO and PM_{10} because there is no annual standard.

e. Emission rate of three (3) MLC compressor engines, FD 9-11.
f. Emission rate of two HPU engines, FD 12 and13.
g. Emission rate of the port and starboard cranes, FD 14 and 15. Emissions have been modeled out of the starboard crane engine stack.
h. Emission rate of three (3) cementing engines, FD 16-18.
i. Emission rate of two (2) logging winch engines, FD 19 and 20. The emission rate has been modeled out of the cementing engine stack.
j. The long term emission rates for these emission units are different from the short term emission modeled.
k. Emission rate of two (2) heat boilers, FD 21 and 22.
l. Emission rate of one (1) incinerator, FD 23.
m. Ice Breaker #1 emission rates represent the sum total of 96 volume sources.
n. Ice Breaker #2 emission rates represent the sum total of 48 volume sources.
o. Oil Spill ResponseK emission rates represent the sum total of 40 volume sources (i.e., three work boats).
p. Oil Spill ResponseN emission rates represent the sum total of 40 volume sources.

Table 5
Secondary Operating Scenario - EPA Calculated vs Shell Modeled Emission Rates

Emission Units or Sources [b]	Total Emission Rate [a]									
	SO_2		NO_2		CO		PM_{10}		$PM_{2.5}$	
	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)	EPA (lbs/hr)	Shell (lbs/hr)
Replenishment (ST) [c,d]	0.8300	0.8262	4.5000	4.5071	3.8800	3.8833	0.3175	0.3167	0.3175	0.3167
Replenishment (LT) [c,d]	0.2003	0.2063								
Emergency Generator [c,e],	0.0005	0.0005	0.0454	0.0450	0.6000	0.6000	0.0088	0.0090	0.0088	0.0090
Bow Ice Removal [c,f,g,h]							1.3500	1.3470	0.6600	0.6650
Supply Ship Transit (ST) [c,i]	2.4224	2.4229	5.4849	5.4889	8.6683	8.6980	0.4145	0.4149	0.3325	0.3328
Supply Ship Transit (LT) [c,i]	0.2050	0.2019								
Anchor Deployment [j,k,l]							24.2300	24.2246	11.9700	11.9697
Anchor Retrieval [j,k,l]							24.2300	24.2246	11.9700	11.9697

Source: See Statement of Basis for detailed discussion of emission rates.

a. The reason for differences between EPA and Shell calculated emission rates can be attributed in part, to rounding off, number of significant digits carried forward in each calculation, and the calculation sequence.
b. (ST ≡ Short Term.) (LT ≡ Long Term.)
c. Occurs during Frontier Discoverer drilling operations, that is with POS #1.
d. Supply ship is tied to the Frontier Discoverer.
e. The emergency generator emissions were combined with FD 1-6 emissions and modeled.
f. Bow ice removal is performed by Ice Breaker #2 using six volume sources to represent the activity.
g. Minimum separation distance between Frontier Discover and Ice Breaker #2 is 100-meters during this activity.
h. During a 24-hour day, Ice Breaker #2 will either manage ice or manage ice and remove ice from the bow of the Frontier Discoverer.
i. The supply ship is modeled during the last 5-kilometers to the Frontier Discoverer using 80 volume sources to represent the transit.
j. No drilling occurs during this operation. This operation is performed by Ice Breaker #2 and is represented by 1004 volume sources.
k. Minimum separation distance between Frontier Discover and Ice Breaker #2 during this operation is 900-meters.
l. During a 24-hour day, the Ice Breaker #2 will either manage ice or manage ice and deploy/retrieve anchors.

Table 6
Primary 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	154.10	55.20	17.40	710.00	32.89	0.32
MLC Comp Eng [a,b,c]	Point	102.00	63.00	13.10	699.80	40.00	0.21
HPU Eng [a,b,c]	Point	79.00	65.00	10.70	699.80	40.00	0.18
Cementing Eng	Point	95.00	67.00	10.70	800.00	46.60	0.18
Port Crane Eng [a,b,c]	Point	114.00	66.00	18.29	672.00	20.10	0.25
Stbd Crane Eng [a,b,c]	Point	70.10	43.70	18.29	672.00	20.10	0.25
Heat Boiler [a,b,c]	Point	154.30	52.20	17.40	478.00	7.34	0.46
Log Winch Eng [a,b,c]	Point	120.70	55.20	13.11	710.90	52.97	0.10
Incinerator [a,b,c]	Point	61.00	65.00	7.01	623.00	10.00	0.46
Over Land Heater [d]	Point [d]	0.00	0.00	7.62	478.00	6.60	0.46
	[e] [f]			Height (m)	Sigma-y_o (m)	Sigma-z_o (m)	
Ice Breaker #1 [a,c,e]	Volume [g]		[d]	25.22	46.51	9.21	
Ice Breaker #2 [a,c,f]	Volume		[e]	25.22	46.51	9.21	
Oil Spill ResponseK [a,c,g,h]	Volume		[f]	3.38	23.26	1.42	
Oil Spill ResponseN [a,c,h,i]	Volume		[g]	17.55	23.26	6.38	

Reference: Shell 2009a

a. Origin of coordinate system (93, 55) meters or the drill hole location below the Frontier Discoverer.
b. Frontier Discoverer emission units. A single location is 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 is meters above the surface or water line.
d The coordinate system used to model the over land located heater is different from that used by the over water emission sources. The origin is at (0, 0) m, or 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. There are three work boats.
h. Oil Response ResponseK and Oil Spill ResponseN are divided into 40 volume sources each.
i. Oil Spill ResponseN is located about 2000-meters downwind of the drill hole location. The vessel is the Nanuq.

Figure 7
Secondary Operating Scenario - Location and Stack Parameters

Emission Units or Sources	Operating Scenario	Location		Stack Parameters			
		x (m)	y (m)	Height (m)	Temperature (K)	Velocity (m/sec)	Diameter (m)
Resupply [a,b]	SOS #3	70.00	-12.00	15.24	700.00	4.00	0.18
Emergency Generator [a,c]	SOS #4						
				Height (m)	Sigma-y_o (m)	Sigma-z_o (m)	
Bow Ice Removal [a,d]	SOS #1	[e]	[e]	24.43	23.26	9.21	
Supply Ship Transit [a]	SOS #2	[f]	[f]	15.24	29.07	6.38	
Anchor Deployment [g]	SOS #5	[h]	[h]	24.43	23.26	9.43	
Anchor Retrieval [g]	SOS#6	[h]	[h]	24.43	23.26	9.43	

Reference: Shell 2009b, Winges, K. 2009a, 2009b, 2009c and 2009d.

a. Occurs during Frontier Discoverer drilling operations or POS #1.
b. Supply ship Kilabuk is tied to the Frontier Discoverer.
c. The emergency generator emissions were modeled with FD 1-6 emissions.
d. Bow ice removal is performed by Ice Breaker and using six volume sources to represent the activity.
e. Minimum separation distance between Frontier Discover and Ice Breaker is 100-meters during this bow ice removal.
f. The supply ship is modeled during the last 5-kilometers to the Frontier Discoverer using 80 volume sources to represent the transit.
g. Occurs when there is no drilling operation. This activity is represented by 1004 volume sources.
h. Minimum separation distance between Frontier Discover and Ice Breaker #2 is 900-meters during anchor deployment and retrieval.

Exhibit 8
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Table 8
Representative Background Air Quality Data Measurements

Air Pollutant	Averaging Period	Measured Concentration [a] ($\mu g/m^3$)
Sulfur Dioxide (SO2)	3-Hour	18.34
	24-Hour	1.48
	Annual [b]	1.00
Nitrogen Dioxide (NO2)	Annual [b]	3.76
Carbon Monoxide (CO)	1-Hour	1055.70
	8-Hour	540.50
Particulate matter equal to or less than 10 microns (PM10)	24-Hour	66.00
Particulate matter equal to or less than 2.5 microns (PM2.5) [c]	24-Hour	8.00
	Annual [b]	4.00
Ozone (O3)	1-Hour	113.68
	8-Hour	96.04

Reference: CPAI 2009a, 2009b, 2009c, and 2009d, USEPA July 2009b

a. The period of record for the data collection at Wainwright is November 08, 2008 to June 30, 2009.
b. Highest measured monthly value.
c. $PM_{2.5}$ measurements collected from 06 March 2009 to 30 June 2009 and meets the conditions contained in the monitoring plan (CPAI 2008).

Table 9
Preconstruction Significant Monitoring Levels

Air Pollutant	Averaging Time	Predicted ($\mu g/m^3$)	Level ($\mu g/m^3$)	Percent
Sulfur Dioxide (SO_2)	24-Hour	28.00	13	215.38
Nitrogen Dioxide (NO_2)	Annual	20.80	14	148.57
Carbon Monoxide (CO)	8-Hour	352.00	575	61.22
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	28.20	10	282.00
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)			a	
Ozone (O_3)		b		

Reference: Shell 2009a

a. EPA has not promulgated a $PM_{2.5}$ monitoring threshold.
b. The net emissions increase of oxides of nitrogen and volatile organic compound emissions exceed 100 tons per year. As a result, Shell is required to conduct an O_3 analysis including data collection. See Statement of Basis and Appendix B for emission calculations.

Table 10
Class II Area Significant Impact Levels and Radius

Air Pollutant	Averaging Time	Predicted (µg/m^3)	Level (µg/m^3)	Percent	SIA Radius [a] (km)
Sulfur Dioxide (SO_2)	3-Hour	74.00	25.00	296.00	18.80
	24-Hour	28.00	5	560.00	50.00
	Annual	2.10	1	210.00	8.70
Nitrogen Dioxide (NO_2)	Annual	20.80	1	2080.00	50.00
Carbon Monoxide (CO)	1-Hour	391.20	2000	19.56	NA
	8-Hour	352.00	500	70.40	NA
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	28.20	5	564.00	50.00
	Annual	1.90	1	190.00	14.40
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour		[b]		
	Annual		[b]		
Ozone (O_3)			[c]		

Reference: Shell 2009a

NA ≡ Not Applicable.

a. The significant impact area radius is the furthest modeled distance in which there is a significant impact, or a maximum radius of 50-kilometers.
b. Because EPA has not promulgated $PM_{2.5}$ significant impact levels, a NAAQS analysis is required for this air pollutant.
c. The net emissions increase of oxides of nitrogen and volatile organic compound emissions exceed 100 tons per year. As a result, Shell is required to conduct an O_3 analysis including data collection. See Statement of Basis and Appendix A for emission calculations.

Table 11
Primary Operating Scenario #1 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Predicted ($\mu g/m^3$)	Existing ($\mu g/m^3$)	Total [a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
Sulfur Dioxide (SO_2)	3-Hour	74.00	18.34	92.34	1300	7.10
	24-Hour	28.00	1.48	29.48	365	8.08
	Annual	2.10	1.00	3.10	80	3.88
Nitrogen Dioxide (NO_2)	Annual	20.80	3.76	24.56	100	24.56
Carbon Monoxide (CO)	1-Hour	391.20	1055.70	1446.90	10000	14.47
	8-Hour	352.00	540.55	892.55	40000	2.23
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	28.20	66.00	94.20	150	62.80
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	25.60	8.00	33.60	35	96.00
	Annual	1.70	4.00	5.70	15	38.00

Reference: Shell 2009a

a. The sum of the "predicted" impacts and "existing" background.

Exhibit 8
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Table 12a
Secondary Operating Scenario #1 and #2 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Existing (µg/m³)	Scenario [a] SOS #1 Predicted (µg/m³)	Scenario [a] SOS #1 Total [b] (µg/m³)	Scenario [a] SOS #2 Predicted (µg/m³)	Scenario [a] SOS #2 Total [b] (µg/m³)	NAAQS (µg/m³)	Percent [c]
Sulfur Dioxide (SO_2)	3-Hour						1300	
	24-Hour						365	
	Annual						80	
Nitrogen Dioxide (NO_2)	Annual						100	
Carbon Monoxide (CO)	1-Hour						10000	
	8-Hour						40000	
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	66.00	27.72	93.72	28.20	94.20	150	62.80
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	8.00	25.70	33.70	25.60	33.60	35	96.00
	Annual						15	

Reference: Shell 2009a, Winges, K. 2009a, 2009b, 2009c and 2009d.

a. SOS #1: Frontier Discoverer bow ice removal by Ice Breaker_B occurs concurrently with drilling activities.
SOS #2: Supply ship transit for replenishment of Frontier Discover occurs concurrently with drilling activities.
b. The sum of the "predicted" impact and "existing" background.
c. Percent is higher of SOS #1 and SOS #2.

Table 12b

Secondary Operating Scenario #3 and #4 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Existing ($\mu g/m^3$)	Scenario [a] SOS #3 Predicted ($\mu g/m^3$)	SOS #3 Total [b] ($\mu g/m^3$)	SOS #4 Predicted ($\mu g/m^3$)	SOS #4 Total [b] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent [c]
Sulfur Dioxide (SO_2)	3-Hour	18.34	74.00	92.34	74.00	92.34	1300	7.10
	24-Hour	1.48	28.00	29.48	28.00	29.48	365	8.08
	Annual	1.00	2.10	3.10	2.10	3.10	80	3.88
Nitrogen Dioxide (NO_2)	Annual	3.76	20.80	24.56	20.80	24.56	100	24.56
Carbon Monoxide (CO)	1-Hour	1055.70	391.20	1446.90	391.20	1446.90	10000	14.47
	8-Hour	540.55	352.00	892.55	352.00	892.55	40000	2.23
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	66.00	28.20	94.20	28.20	94.20	150	62.80
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	8.00	25.60	33.60	25.60	33.60	35	96.00
	Annual	4.00	1.70	5.70	1.70	5.70	15	38.00

Reference: Shell 2009a

a. SOS #3: Supply ship replenishment of Frontier Discoverer occurs concurrently with drilling activities .
SOS #4: Testing of emergency generators occurs concurrently with drilling activities.

b. The sum of the “predicted” impact and “existing” background.

c. Percent is higher of SOS #3 and SOS #4.

Exhibit 8
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Table 12c
Secondary Operating Scenario #5 and #6 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Existing (µg/m^3)	Scenario [a,b] SOS #5 Predicted (µg/m^3)	Scenario [a,b] SOS #5 Total [c] (µg/m^3)	Scenario [a,b] SOS #6 Predicted (µg/m^3)	Scenario [a,b] SOS #6 Total [c] (µg/m^3)	NAAQS (µg/m^3)	Percent [d]
Sulfur Dioxide (SO_2)	3-Hour						1300	
	24-Hour						365	
	Annual						80	
Nitrogen Dioxide (NO_2)	Annual						100	
Carbon Monoxide (CO)	1-Hour						10000	
	8-Hour						40000	
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	66.00	26.10	92.10	26.10	92.10	150	61.40
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	8.00	17.07	25.07	17.07	25.07	35	71.63
	Annual						15	

Reference: Winges, K 2009a, 2009b, 2009c and 2009d

a. SOS #5: Anchor deployment by ice breaker.
SOS #6: Anchor retrieval by ice breaker.
b. Only PM_{10} and $PM_{2.5}$ were modeled for SOS #5 and SOS #6 because their total concentration under POS #1 approached NAAQS.
c. The sum of the “predicted” impact and “existing” background.
d. Percent is higher of SOS #5 and SOS #6.

Exhibit 8
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Table 13
Nearest Village Total Concentration Comparison Impact with NAAQS

Air Pollutant	Averaging Period	Predicted [a] Wainwright ($\mu g/m^3$)	Predicted [a] Pt Lay ($\mu g/m^3$)	Exist ($\mu g/m^3$)	Total [b] Wainwright ($\mu g/m^3$)	Total [b] Pt Lay ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Wainwright Percent	Pt Lay Percent
Sulfur Dioxide (SO_2)	3-Hour	8.90	9.50	18.34	27.24	27.84	1300	2.10	2.14
	24-Hour	4.50	4.70	1.48	5.98	6.18	365	1.64	1.69
	Annual	0.30	0.70	1.00	1.30	1.70	80	1.63	2.13
Nitrogen Dioxide (NO_2)	Annual	2.90	3.10	3.76	6.66	6.86	100	6.66	6.86
Carbon Monoxide (CO)	1-Hour	36.50	39.00	1055.70	1092.20	1094.70	10000	10.92	10.95
	8-Hour	32.80	35.10	540.55	573.35	575.65	40000	1.43	1.44
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	5.20	5.50	66.00	71.20	71.50	150	47.47	47.67
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	4.50	4.80	8.00	12.50	12.80	35	35.71	36.57
	Annual	0.30	0.40	4.00	4.30	4.40	15	28.67	29.33

Reference: Shell 2009b

a. Impacts were predicted at two nearby villages: Wainwright at 110-km and Point Lay is 100-km.
b. The sum of the "predicted" impact and "exist" background.

Table 14
Primary Operating Scenario #1 Predicted Concentration Impact Comparison with Class II Area Air Quality Increments

Air Pollutant	Averaging Period	Predicted (µg/m^3)	Increment (µg/m^3)	Percent
Sulfur Dioxide (SO_2)	3-Hour	74.00	512	14.45
	24-Hour	28.00	91	30.77
	Annual	2.10	20	10.50
Nitrogen Dioxide (NO_2)	Annual	20.80	25	83.20
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	28.20	30	94.00
	Annual	1.90	17	11.18
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)			[a]	

Reference: Shell 2009a

a. EPA has not promulgated $PM_{2.5}$ increments.

Table 15
Primary Operating Scenario #1Nearest Village Predicted Concentration Impact
Comparison with Class II Area Air Quality Increments

Air Pollutant	Averaging Period	Predicted [a,b]		Increment		
		Wainwright ($\mu g/m^3$)	Pt Lay ($\mu g/m^3$)	($\mu g/m^3$)	Wainwright Percent	Pt Lay Percent
Sulfur Dioxide (SO_2)	3-Hour	8.90	9.50	512	1.74	1.86
	24-Hour	4.50	4.70	91	4.95	5.16
	Annual	0.30	0.40	20	1.50	2.00
Nitrogen Dioxide (NO_2)	Annual	2.90	3.10	25	11.60	12.40
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	5.20	5.50	30	17.33	18.33
	Annual	0.40	0.40	17	2.35	2.35
Particulate Matter equal to or less than 2.5 microns ($PM_{2\ 5}$)				[b]		

Reference: Shell 2009a

a. Impacts were predicted at two nearby villages: Wainwright at 110-km and Point Lay is 100-km.
b. EPA has not promulgated $PM_{2.5}$ increments.

Table 16
Secondary Operating Scenario Predicted Concentration Impacts Comparison
with Class II Area Air Quality Increments

Air Pollutant	Averaging Period	Secondary Operating Scenarios #1	#2	#3	#4	#5	#6	Increment ($\mu g/m^3$)	Percent HI SOS [a]
Sulfur Dioxide (SO_2)	3-Hour			74.00	74.00			512	14.45
	24-Hour			28.00	28.00			91	30.77
	Annual			2.10	2.10			20	10.50
Nitrogen Dioxide (NO_2)	Annual			20.80	20.80			25	83.20
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	27.72	28.20	28.20	28.20	26.10	26.10	30	94.00
	Annual			1.90	1.90			17	11.18
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)								[b]	

Reference: Shell 2009a

a. Percent of highest prediction amongst the six scenarios.
b. EPA has not promulgated $PM_{2.5}$ increments.

Exhibit 8
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Table 17
Primary Operating Scenario #2 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Predicted ($\mu g/m^3$)	Exist ($\mu g/m^3$)	Total [c] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
Sulfur Dioxide (SO_2)	3-Hour	56.20	18.34	74.54	1300	5.73
	24-Hour	37.50	1.48	38.98	365	10.68
	Annual	3.10	1.00	4.10	80	5.13
Nitrogen Dioxide (NO_2)	Annual	3.70	3.76	7.46	100	7.46
Carbon Monoxide (CO)	1-Hour	24.60	1055.70	1080.30	10000	10.80
	8-Hour	22.10	540.55	562.65	40000	1.41
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	9.80	66.00	75.80	150	50.53
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	9.80	8.00	17.80	35	50.86
	Annual	0.81	4.00	4.81	15	32.07

Reference: Steen, R. 2009a

a. The sum of the "predicted" impact and "exist" background.

Table 18
Primary Operating Scenario #2 Predicted Concentration Impact Comparison
with Class II Area Air Quality Increments

Air Pollutant	Averaging Period	Predicted ($\mu g/m^3$)	Increment ($\mu g/m^3$)	Percent of Increment
Sulfur Dioxide (SO_2)	3-Hour	56.20	512	10.98
	24-Hour	37.50	91	41.21
	Annual	3.10	20	15.50
Nitrogen Dioxide (NO_2)	Annual	3.70	25	14.80
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	9.80	30	32.67
	Annual	0.81	17	4.76
Particulate Matter equal to or less than 2.5 microns ($PM_{2\,5}$)			[a]	

Reference: Steen, R. 2009a

a. EPA has not promulgated $PM_{2.5}$ increments.