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

Date of Proposed Permit: January 8, 2010

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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
C.F.R.. .... 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 C.F.R. 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

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1. INTRODUCTION, PROJECT DESCRIPTION AND PUBLIC PARTICIPATION

1.1 Introduction

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

Under these programs, Shell Gulf of Mexico Inc (Shell)[1] has applied for a major source permit to authorize mobilization and operation of the Frontier Discoverer drillship (Discoverer) and its associated fleet at various drill sites in the Chukchi Sea outer continental shelf (OCS) off the North Slope of Alaska in connection with an exploratory oil and gas drilling program (exploration drilling program).

EPA initially proposed a draft OCS/PSD permit for Shell's exploration drilling program in the Chukchi Sea for public comment on August 20, 2009 (August 2009 proposed permit), with an extended public comment period running through October 20, 2009. EPA conducted government-to-government consultation as requested by affected Native Villages, informational meetings, and public hearings in Barrow and Anchorage, Alaska during the week of September 21, 2009. After reviewing the comments received on the August 2009 proposed permit, EPA has decided to issue a new modified proposed permit and is initiating a new public comment period to ensure the public has an opportunity to review and comment on the new modified permit.[2]

As with the August 2009 proposed permit, this new modified proposed permit will allow Shell to operate the Frontier Discoverer drillship and associated fleet for a multi-year exploration drilling program within Shell's current lease blocks in lease sale 193 on the Chukchi Sea OCS, beyond

[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.

[2] As discussed in Section 1.3.1, because EPA is reproposing the permit in its entirety and will not be taking any further action on the August 20, 2009 initial proposed permit, EPA will not be responding to comments on the August 20, 2009 proposed permit. To the extent a commenters believes that comments provided during the comment period for the August 20, 2009 proposed permit have not been addressed by the new modified proposed permit or new modified Statement of Basis, the commenter should resubmit those specific un-addressed comments during the current comment period for this new modified proposed permit.

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25 miles from Alaska's seaward boundary. Because the drillship operations would be a "major" source of air pollutants, the permit requires that the operations meet PSD program requirements.

Major changes made to the new modified proposed permit since the August 2009 proposed permit include:

- Overall, emissions of all PSD pollutants allowed under the new modified proposed permit are lower, with substantial reductions of particulate matter emissions (from 184 tons per year (tpy) to 52 tpy for fine particulate matter) and sulfur dioxide (from 181 tpy to less than 2 tpy) as compared to the August 2009 proposed permit.

Table 1.1 - Permitted Air Pollutant Emissions from Discoverer and Associated Fleet as OCS Source at all Locations

Air Pollutant	Initial Proposed Emissions (tpy)	Revised Emissions (tpy)
Carbon Monoxide (CO)	762	449
Nitrogen Oxides (NO_x)	1965	1188
Particulate Matter Less than 2.5 ($PM_{2.5}$)	184	52
Particulate Matter Less than 10 (PM_{10})	210	58
Sulfur Dioxide (SO_2)	181	2
Volatile Organic Compounds (VOC)	166	87

- The permit proposes two alternatives for when the Discoverer is considered an "OCS source" under the permit and when the emission limitations and other operating restrictions apply. In the August 2009 proposed permit and in this proposal, EPA seeks comment on considering the Discoverer to be an OCS source when it is attached by a single anchor to the seabed. EPA is also soliciting comment on an alternative proposal to consider the Discoverer to be an OCS source when it is sufficiently secure and stable to commence exploratory activity at a drill site.
- The proposed permit requires the use ultra-low sulfur diesel fuel in all vessels in the associated fleet when such a vessel is within 25 miles of the Discoverer and the Discoverer is operating as an OCS source. This change results in a decrease in emissions of SO_2 from 181 tpy to less than 3 tpy.
- The proposed permit requires the use of an anchor handler/icebreaker equipped with selective catalytic reduction controls on the main diesel engines, resulting in much lower emissions of NO_x.
- For the oil spill response vessel, the daily fuel limit for the two propulsion engines is increased. For the two generator engines on the vessel, the daily fuel limit is decreased. The proposed permit requires catalytic diesel particulate filters on the propulsion and generator engines. The net result is a small increase in emissions of NO_x from the vessel, but substantial decreases in particulate matter emissions and SO_2 emissions, and moderate decreases in CO and VOC emissions from this vessel.
- The logging winch engines on the Discoverer have been replaced with newer engines, one of which is a newer Tier 3 engine that is larger in horsepower than the engine it replaced.

- The permit requires oxidation catalysts on the compressor diesel engines on the Discoverer (all new Tier 3 engines), which reduces emissions of particulate matter, VOC, and CO.
- The hours of operation of the emergency generator on the Discoverer are increased from 20 minutes to two hours a month to be consistent with U.S. Coast Guard requirements.
- The fuel limits for the cementing units and logging winch engines on the Discoverer are decreased to offset the small increase in the emissions from the emergency generator.
- The proposed permit requires tighter restrictions on the waste throughput limit for the incinerator on the Discoverer, which are tied to the use of the Discoverer's HPU engines, resulting in an overall reduction of emissions from the incinerator and the HPU engines as compared to the August 2009 proposed permit. The permit also requires development and implementation of a waste segregation plan.
- For the main generator engines on the Discoverer and for the icebreaker engines, the permit requires a compliance assurance regime based on the monitoring of engine loads instead of monitoring of fuel usage.
- Certain restrictions on the locations of the icebreakers in relation to the Discoverer while traveling on non-icebreaking activities are eliminated and replaced with requirements to record the duration, purpose and operating loads at such locations.
- The number of operating loads required for the stack testing of the newer and smaller engines and the boilers on the Discoverer and the non-propulsion engines on the icebreakers is reduced.
- Monitoring of the ammonia emissions from controls on the Discoverer's main generator engines is changed from continuous monitoring to stack testing.

Again, the net result of the changes in this new modified proposed permit as compared to the August 2009 proposed permit is a reduction of all PSD pollutants emitted by Shell's exploration drilling program, with a substantial reduction of particulate matter emissions and SO_2.

Application Chronology[3]

November 2008-August 2008

Date	Document Description
11/12/2008	Modeling Protocol for Chukchi and Beaufort Sea Exploration Drilling Program
12/11/2008	Letter from Susan Childs, Shell Offshore, Inc. to Richard Albright, EPA regarding Preconstruction Permit Application for Frontier Discoverer Drill Vessel in Chukchi Sea, beyond the 25-mile Alaska Seaward Boundary
01/15/2009	E-mail from Tim Martin, Air Sciences, Inc. to Herman Wong, EPA regarding the Discoverer Chukchi Source Contribution
01/16/2009	Letter from EPA to Shell Regarding the Incompleteness Determination for the Chukchi PSD Permit Application
01/26/2009	E-mail from Tim Martin, Air Sciences, Inc. to Herman Wong, EPA regarding the Shell Chukchi Icebreaker Characterization

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

02/23/2009	Shell Offshore Inc. Outer Continental Shelf Pre-construction Air Permit Revised Application, Frontier Discover Chukchi Sea – Cover Letter
02/23/2009	Shell Offshore Inc. Outer Continental Shelf Pre-construction Air Permit Revised Application, Frontier Discover Chukchi Sea – Revised Application
02/23/2009	Shell Offshore Inc. Outer Continental Shelf Pre-construction Air Permit Revised Application, Frontier Discover Chukchi Sea – Appendices A-G
03/12/2009	Letter from Richard Albright, EPA to Susan Childs, Shell regarding Incompleteness Determination for the Chukchi PSD Permit Application Received on February 24, 2009
03/20/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair and Herman Wong, EPA regarding Chukchi Sea Leases
04/14/2009	E-mail from Tim Martin, Air Sciences, Inc. to Herman Wong, EPA regarding the Impact Modeling for Warehouse Emissions – Wainwright or Barrow
04/23/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Conference Call on Icebreakers
04/27/2009	E-mail from Tim Martin, Air Sciences, Inc. to Rodger Steen regarding Volume Sources
05/05/2009	E-mail from Rodger Steen, Air Sciences, Inc. regarding Updated Emissions Discoverer El with 84-day well site limit removed & updated BACT for FD20
05/11/2009	E-mail from Thomas Damiana, AECOM to Herman Wong, EPA regarding Wainwright Audit Reports
05/14/2009	E-mail from Rodger Steen, Air Sciences to Sabrina Pryor regarding Proposed Alternative Handling of Ice Management Fleet, Supply Ship, Nanuq
05/18/2009	Shell Offshore Inc. – Response to March 12, 2009 2nd EPA Letter of Incompleteness – Revised Preconstruction Permit Application for Frontier Discoverer Drillship in Chukchi Sea, Alaska, beyond 25-mile Alaska Seaward Boundary
05/19/2009	E-mail from Thomas Damiana, AECOM to Herman Wong, EPA regarding Wainwright March 2009 Summary Report
05/20/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Hypothetical maximum Ice Management Vessel and joining of ICE engine limits
05/29/2009	Letter from Susan Childs, Shell to Janis Hastings, EPA regarding Shell Offshore Inc. – Updated Responses to March 12, 2009, 2nd EPA Letter of Incompleteness
06/01/2009	Shell Offshore Inc. – Supplemental Response – Additional Impact Analysis
06/05/2009	E-mail from Rodger Steen, Air Sciences regarding Updated BACT Analysis for Volatile Organic Compounds sources
06/05/2009	E-mail from Kirk Winges, ENVIRON to Tim Martin, Air Sciences, Inc. regarding Shell Chukchi and Beaufort Sea PSD Applications
06/09/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Ice Removal – Disco Bow
06/16/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Information on Non-Criteria Regulated Air Pollutants with Spreadsheet titled "Discoverer Emissions Chukchi OCS_061509.xls"

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06/16/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair and Herman Wong, EPA regarding Shell Discoverer non-criteria pollutants with attachment titled “Resp to EPA Disco Non-criteria 06162009.pdf”
06/19/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair and Paul Boys, EPA regarding Discoverer Chukchi Sea - Criteria Emissions in your requested format and Compliance Monitoring Proposal
06/23/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Follow-Up Regarding Anchor Handling and Bow Emissions
06/23/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding PM2.5 Discoverer Bow
06/23/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA Regarding PM10 Discoverer Bow
06/23/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding PM2.5 Anchor Handling
06/23/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Modeling Files
06/24/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Information on Resupply Ship
06/26/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Request for Information on Discoverer +/-15 degree Re-Orientation
06/30/2009	E-mail from Kirk Winges, ENVIRON to Pat Nair, EPA regarding Anchor Setting Emissions
07/06/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Herman Wong, EPA regarding Associated Emissions
07/06/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Title VI Potential to Emit
07/12/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, EPA regarding Questions on D399 Anticipated Compliance Conditions
07/13/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Ice Removal – Discoverer Bow
07/15/2009	E-mail from Kirk Winges, ENVIRON regarding Anchor Setting Emissions for PM 2.5
07/15/2009	E-mail from Kirk Winges, ENVIRON regarding Anchor Setting Emissions for PM 10
07/16/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Bow Washing Emissions for PM 2.5 and PM 10
07/16/2009	E-mail from Thomas Damiana, AECOM to Herman Wong, EPA regarding Wainwright Near-Term Monitoring Program May 2009 Data Summary
07/17/2009	E-mail from Tim Martin, Air Sciences, Inc. to Herman Wong, EPA regarding Bow Washing Emissions for PM 2.5 and PM 10
07/17/2009	E-mail from Tim Martin, Air Sciences, Inc. to Herman Wong, EPA regarding Background Concentrations
07/28/2009	E-mail from Thomas Damiana to Christopher Hall, EPA regarding Wainwright Near-Term Monitoring Project PM2.5 Data
07/31/2009	Letter from Richard Albright, EPA to Susan Childs, Shell Transmitting the Completeness Determination for the Chukchi PSD Permit Application
08/10/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Janis Hastings, EPA regarding Responses to draft disco/Chukchi permit – the largest issues

08/12/2009	E-mail from Susan Childs, Shell to Julie Vergeront, EPA regarding SGOMI and signing authority
08/12/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA Regarding Example Model Runs
08/12/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Shell Request for a Modification on the Discoverer Location Restrictions
08/13/2009	E-mail from Kirk Winges, ENVIRON to Dave Bray, EPA regarding Geometry
08/13/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Example Model Runs
08/13/2009	E-mail from Kirk Winges, ENVIRON to Herman Wong, EPA regarding Example Model Runs

September 2009 to December 2009

Date	Document Description
09/17/2009	Letter from Susan Childs, Shell to, EPA re: Shell Gulf of Mexico Inc. Comments on August 2009 Proposed Discoverer/Chukchi OCS/PSD Permit to Construct
09/17/2009	Supplemental, BIRP Emissions Workbook, ISC-Prime Results
10/08/2009	Letter from Susan Childs, Shell, to EPA, re: Shell Gulf of Mexico Inc. Comments on the August 2009 Proposed Discoverer/ Chukchi OCS/PSD Permit to Construct (permit tracked to show Shell's requested changes)
10/19/2009	E-mail and attachments from Rodger Steen, Air Science, Inc. to Pat Nair, EPA re: Clarifications Needed on Icebreaker #2
10/20/2009	Letter from Susan Childs Shell, to EPA re: Shell Gulf of Mexico, Inc. Supplemental Comments on the August 2009 Proposed Discoverer/Chukchi OCS/PSD Permit to Construct
10/20/2009	Letter from Susan Childs, Shell, to EPA re: Shell Gulf of Mexico, Inc. Supplemental Comments on the August 2009 Proposed Discoverer/Chukchi OCS/PSD Permit to Construct (correction)
11/13/2009	Document from Shell provided to EPA re: Conceptual Plan: Potential Re-Proposal of Shell Chukchi Draft PSD Permit
11/18/2009	E-mail from Kirk Winges, ENVIRON, re: Kilabuck
11/19/2009	E-mail from Kirk Winges, ENVIRON, to Pat Nair, EPA, re: Scale Idea
11/23/2009	Letter from Susan Childs, Shell to Janis Hastings, EPA, re: Supplemental Application Support Materials in Response to November 12, 2009 Meeting
11/25/2009	E-mail from Kirk Winges, ENVIRON, re: Supplemental BACT Analysis and Small Engine Stack Testing with attachments,
12/02/2009	E-mail from Kirk Winges, ENVIRON, re: Revised CO Analysis with attachments
12/07/2009	Wainwright Near-Term Ambient Air Quality Monitoring Program Fourth Quarter Data Report August through October 2009 Final – Rev01
12/09/2009	Letter from Susan Childs, Shell, to Rick Albright, EPA, re: Shell Gulf of Mexico Inc. Supplement to Application for Discover/Chukchi OCS/PSD Permit
12/10/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Pat Nair, re: Info on New Engines

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12/11/2009	E-mail from Kirk Winges, ENVIRON, to Paul Boys, EPA, regarding Edited BACT with attachment, “Diesel Engine Best Available Control Technology Analysis, Frontier Discoverer Drill Ship”
12/13/2009	Letter from Susan Childs, Shell, to Rick Albright, EPA, re: Shell Gulf of Mexico Inc. Supplement to Application for Discoverer/Chukchi OCS/PSD Permit with Attachments A-I
12/16/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Dave Bray, EPA, re: Wainwright PM2.5 Analysis with Attachments (Wainwright Precipitation and Wind Statistics)
12/18/2009	E-mail from Rodger Steen, Air Sciences, Inc. to Dave Bray, EPA, re: Discoverer Incinerator Emissions
12/18/09	E-mail from Rodger Steen, Air Sciences, to Dave Bray, EPA, re: PM2.5 and PM10 Wainwright Statistics
12/22/2009	E-mail from Eric Hansen, ENVIRON to Paul Boys, EPA, re: Supplemental BACT Analyses for CO Emissions from MLC and Logging Winch Engines (with attachment: Memorandum from ENVIRON regarding Shell Chukchi Sea PSD Permit and data)

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 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 from lease sale 193 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).

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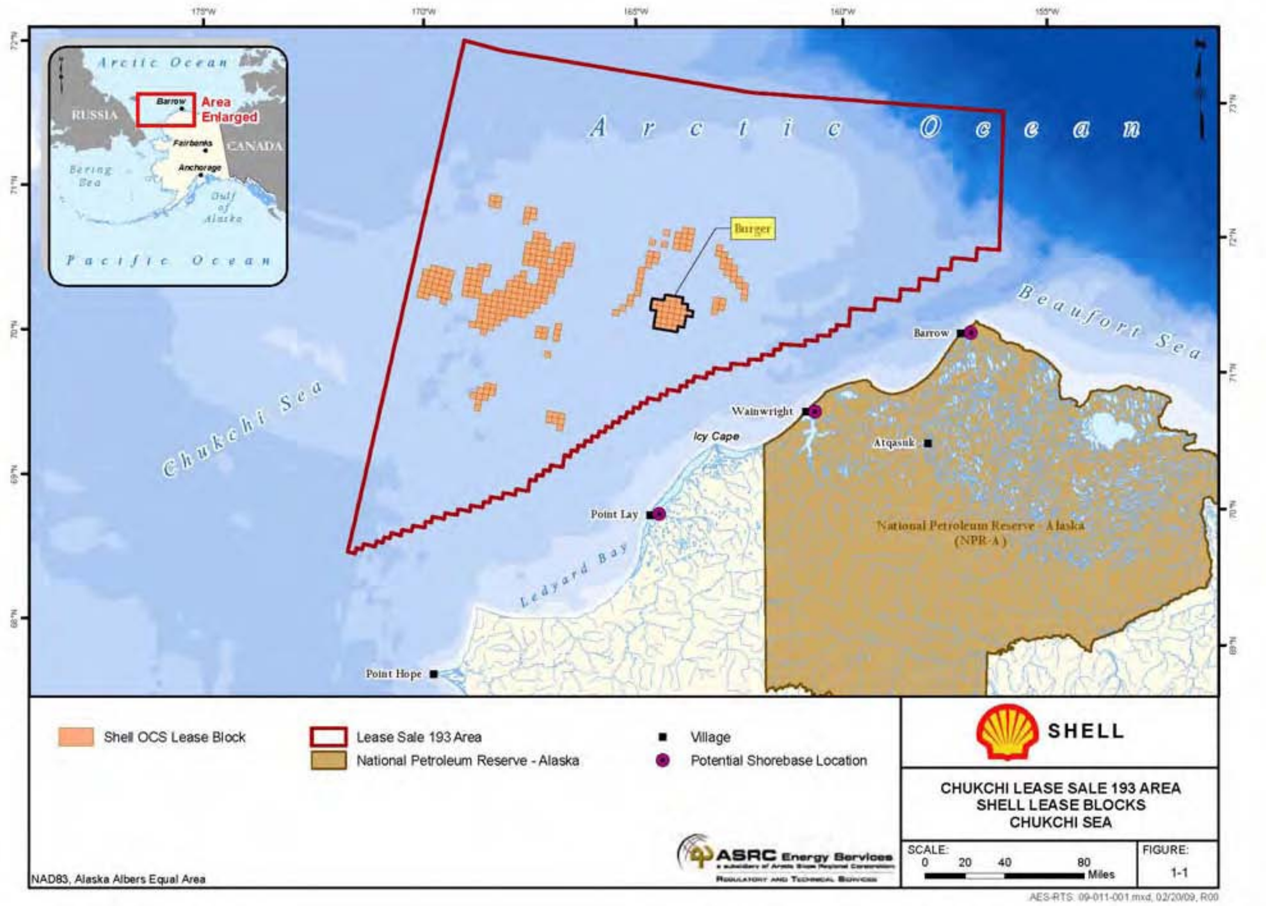
Figure 1-1 – Chukchi Sea Lease Area 193



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>

The Discoverer's operations are supported by an associated fleet that consists of an icebreaker, an anchor handler/icebreaker, a supply ship, an oil spill response ship and oil spill workboats (such support vessels to be referred to hereafter as the "Associated Fleet"). 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 breakers, the Discoverer mobilizes to the desired location. Alternate locations are available in the event that ice conditions at the desired location exceed the fleet's capability to manage ice or conduct operations. Anchors are run and set by the ice breaker/anchor handler vessel; the mooring lines are tensioned; and the Discoverer is thus positioned over the drill site.

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

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

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

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

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

The 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. The Discoverer's 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 through 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

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

As provided in Part 124, EPA is seeking public comment on the new modified proposed Shell OCS/PSD permit for the Chukchi Sea. The public comment period runs from January 8, 2010 through February 17, 2010. All written comments must be postmarked by February 17, 2010. 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. This is the same model that was relied on in the issuance of the August 2009 proposed permit.

Because EPA is reproposing the permit in its entirety and will not be taking any further action on the August 2009 initial proposed permit, EPA will not be responding to comments on the August 2009 proposed permit. If you believe any condition of this permit is inappropriate, you must comment on the permit and raise all reasonably ascertainable issues and submit all reasonably ascertainable arguments supporting your position by the end of the comment period. Any documents supporting your comments must be included in full and may not be incorporated by reference unless they are already part of the record for this permit or consist of state or federal statutes or regulations, EPA documents of general applicability, or other generally available referenced materials. To the extent you believe that comments you provided during the comment period for the August 2009 proposed permit have not been addressed by the new modified proposed permit or new modified Statement of Basis, you should resubmit those specific un-addressed comments during the current comment period for this new modified proposed permit.

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

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consider the comment. Please be aware that any personal information, including addresses or phone numbers that are included with a public comment will be included in the public record for the new modified proposed permit.

Send comments on the proposed permit to:

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

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

1.3.2 Public Hearing and Informational Meetings

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

February 16, 2010
6:00 pm - 9:00 pm
Inupiat Heritage Center
Barrow, Alaska

The purpose of the public hearing is to receive public comments on EPA's proposed OCS/PSD air quality permit for Shell to operate the Frontier Discoverer drillship on the Chukchi Sea OCS. To express interest in attending the public hearing or for more information about the hearing, contact Suzanne Skadowski, EPA community involvement, at 206-553-6689 or skadowski.suzanne@epa.gov. EPA may cancel the public hearing if there is no significant interest expressed in participation. EPA managers and staff will participate in the public hearing by teleconference from EPA offices in Seattle, Washington. The EPA hearing officer will be at the public hearing location in Barrow. Facilities for participating in the public hearing by teleconference are available at the teleconference centers in Wainwright, Point Lay, Point Hope and Atqasuk.

1.3.3 Administrative Record

The record for the new modified proposed permit includes Shell's application, including addendums and supplemental information; all documents in the record for the August 2009 proposed permit; the new modified proposed permit and statement of basis; and all other materials relied on by EPA.

The permit record for the new modified proposed permit is available at the EPA Region 10 Library, 1200 6th Ave, Seattle, Wash. Library hours: 9:00 am–12:00 pm and 1:00 pm–4:00 pm

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Monday-Friday. To request a copy of these materials or a copy of the permit record, contact Suzanne Skadowski as described above.

The permit application, the new modified proposed permit and statement of basis, and the August 2009 proposed permit and statement of basis will also be available at the locations listed below. Please call in advance for available viewing times.

Barrow City Office, 2022 Ahkovak Street, Barrow, Alaska, 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
EPA Region 10 web site: www.yosemite.epa.gov/R10/airpage.nsf/Permits/chukchiap

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

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2. REGULATORY APPLICABILITY

2.1 OCS

The OCS regulations at 40 C.F.R. Part 55 (Part 55) implement Section 328 of the CAA and establish the air pollution control requirements for OCS sources and the procedures for implementation and enforcement of the requirements. 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 <u>only</u> when they are:
>
> (1) Permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing or producing resources therefrom, within the meaning of section 4(a)(1) of OCSLA (43 U.S.C. §1331 et seq.); or
>
> (2) Physically attached to an OCS facility, in which case only the stationary sources aspects of the vessels will be regulated.

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

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 C.F.R. §§ 55.3(b) and (c). In this case, Shell is seeking a permit for an exploration drilling program 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 C.F.R. § 52.21 if the OCS source is also a major stationary source or a major modification to a major stationary source; standards promulgated under Section 112 of the CAA if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of Part C of Title I of the CAA; and the operating permit program under Title V of the CAA and 40 C.F.R. Part 71. See 40 C.F.R. §§ 55.13(a), (c), (d)(2), (e), and (f)(2), respectively. The applicability of these requirements to Shell's exploration drilling program is discussed in Sections 2.2 to 2.7 below.

The OCS regulations also contain provisions relating to monitoring, reporting, inspections, compliance, and enforcement. See 40 C.F.R. §§ 55.8 and 55.9. Section 55.8(a) and (b) authorize EPA to require monitoring, reporting, and inspections for OCS sources and provide

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

Under the PSD regulations, a stationary source is "major" if, among other things, it emits or has the potential to emit (PTE) 100 tpy or more of a "regulated NSR pollutant" as defined in 40 C.F.R. § 52.21(b)(50) and the stationary source is one of a named list of source categories. In addition to the preceding criteria, any stationary source is also considered a major stationary source if it emits or has the potential to emit 250 tpy or more of a regulated NSR pollutant. 40 C.F.R. § 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 C.F.R. § 52.21(b)(4).

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

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

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ambient air quality for each of these pollutants and a demonstration that it will not cause or contribute to a violation of any NAAQS or PSD increment.[5]

2.3 Applicability of the NAAQS and PSD Increments on the OCS

Pursuant to Sections 108 and 109 of the CAA, EPA has promulgated primary and secondary national ambient air quality standards to protect public health and the environment. These national standards apply in the "ambient air," which is defined in 40 C.F.R. § 50.1(e) as "…that portion of the atmosphere, external to buildings, to which the general public has access." The atmosphere over United States territorial waters is "ambient air" and United States law, including 40 C.F.R. Part 50 in which the NAAQS are promulgated, applies within the boundaries of United State and its territorial waters. Nothing in the CAA or EPA's implementing regulations limits the applicability of the NAAQS to ambient air over land or to only ambient air within the jurisdiction of states or tribes.

Pursuant to Section 328 of the CAA, EPA has promulgated regulations at 40 C. F. R. Part 55 to control air pollution from OCS sources in order to attain and maintain federal and state ambient air quality standards and to comply with the provisions of Part C of Title I to prevent significant deterioration of air quality. With respect to PSD, 40 C.F.R. § 55.13(d) states that the PSD rules at 40 C.F.R. § 52.21 shall apply to OCS sources. The PSD rules specifically include, at 40 C.F.R. § 52.21(c), the ambient air increments, and at 40 C.F.R. § 52.21(d), the ambient air ceilings (NAAQS), that must be addressed in the source impact analysis required by 40 C.F.R. § 52.21(k). Further technical information on implementing the PSD increments on the OCS, specifically, the definitions of "baseline concentration," baseline date," and "baseline area," is contained in the EPA 7/2/09 Baseline Memo.

As discussed above, Section 328 of the CAA requires EPA to promulgate regulations to control air pollution from OCS sources in order to attain and maintain federal and state ambient air quality standards and to comply with the provisions of part C of title I to prevent significant deterioration of air quality. While Congress evinced an intent that EPA's regulations ensure protection of air quality onshore, EPA does not interpret Section 328 of the CAA to address only the air quality impacts of offshore sources on onshore areas. Section 328 does not identify a particular area where the requirements to control air pollution from OCS source located offshore must "attain and maintain Federal and State ambient air quality standards" or limit that area to only locations onshore. Furthermore, the D.C. Circuit of the Court of Appeals vacated certain provisions of EPA's Part 55 OCS rules that would have varied the stringency of onshore ambient-based requirements (e.g., the amount of offsets) based on the distance of the OCS source from shore, even though the rules would have ensured protection of onshore air quality because EPA had departed from the CAA's clear directive that the agency promulgate the same "requirements…as would be applicable if the source were located in the corresponding onshore area." *Santa Barbara County Air Pollution Control District v. EPA*, 31 F.3d 1179, 1183 (D.C. Cir. 1994) (citing to Section 328(a)(1) of the CAA). The Court concluded that EPA could not change the stringency of the onshore rules as applicable to offshore sources within 25 miles of a state's seaward boundary. *Id*. Likewise, by making 40 C.F.R. § 52.21 applicable without change

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

to OCS sources located more than 25 miles beyond a state's seaward boundary, *see* 40 C.F.R. § 55.13(d)(2), EPA expressed an intent that the OCS permitting rules applicable to such sources located more than 25 miles beyond a state's seaward boundary would apply in the same manner as 40 C.F.R. § 52.21 would apply to onshore sources. This includes rules with respect to the ambient air quality provisions, which require NAAQS and increment compliance in the ambient air. By requiring Shell to show that its operations comply with NAAQS and increment in the ambient air of Lease Area 193, this permit ensures that air quality is protected everywhere that the PSD rules apply, including onshore and offshore areas.

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

2.4.1. The "OCS Source"

The Discoverer is a turret-moored drillship that is able to move under its own power. During transit, it is propelled by a 7,200 hp Mitsubishi engine. The drill ship uses a Sonat Offshore Drilling turret mooring system that provides the ability for the drill rig floor to remain stationary while the vessel itself may rotate, allowing the vessel bow to be oriented into the wind or broken ice (Exploration Plan 2009, pp 6-7 and Attachment A; United States Patent No. 4,509,448). When the Discoverer reaches the approximate location of the drill site, the anchor handler/icebreaker (Icebreaker #2) is used to attach anchor lines from the Discoverer to the seabed. The mooring system uses a set of eight mooring lines, buoys and anchors which are radially located around the drillship. Drilling can occur when the Discoverer is secured with fewer than eight anchors (United States Patent No. 4,509,448).

Anchor setting involves Icebreaker # 2 backing up to the Discoverer under low power, connecting to the anchor line, reeling out the line, and setting the anchor at approximately 1,000 meters distance, then moving to another anchor opposite the first. Setting of each anchor consumes about 30 minutes and the entire anchoring process consumes no more than 18-24 hours.

Once there are enough mooring lines out to control the position of the vessel with the mooring lines, the vessel is put into position and mooring lines are adjusted to allow operations to be undertaken at a drill site. Once the Discoverer is positioned and the anchor lines re-tensioned at the drill site, the Discoverer's on-site Shell representative declares that the Discoverer is "secure and stable in a position to commence activity at the well location," an event that is recorded in log books on the Discoverer. The propulsion engine is not used during drilling (Shell 12/13/09 Supp. App.; 12/11/09 Anchoring Memo).

When the Discoverer prepares to depart from the drill site, the process is reversed--anchors are de-tensioned and then the anchor lines released. Specifically, Icebreaker #2 moves to the location of an anchor and attaches to the retrieval cable that is marked by a buoy. Icebreaker #2 then tugs on the anchor to release it and raise it, and then ferries it back to the Discoverer as the cable is rewound. Retrieval of each anchor takes about 30 minutes and the entire process generally lasts for less than 12 hours, although it may take as long as 18 hours. There is also a process for a partial or quick release from the anchor lines in the event of approaching hazards (Shell 12/13/09 Supp. App.).

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Drill ships, drill rigs, and drilling platforms used for oil exploration and production vary greatly in configuration. In the August 2009 proposed permit, EPA proposed that the Discoverer be considered an "OCS source" within the meaning of 40 C.F.R. § 55.2 from the time between the placement of the first anchor on the seabed to the removal of the last anchor from the seabed at a drill site. The initial proposed permit also prohibited operation of the propulsion engine while the Discoverer is an OCS source, that is, after placement of the first anchor on the seabed.

During the public comment period on the August 2009 proposed permit, the Mineral Management Services (MMS) expressed concern with the prohibition on operation of the propulsion engine after anchoring and requested that the permit clarify and accommodate the use of the propulsion engine in emergency situations. (MMS 10/20/09). Other commenters also questioned whether the Discoverer could safely anchor without using the propulsion engines.

Shell commented that it believed the Discoverer was not an OCS source within the meaning of Section 328 of the CAA and 40 C.F.R. § 55.2 until the Discoverer is stabilized and the anchoring process is complete. Shell also said it would attempt to meet the requirements to shut down the propulsion engines during the anchoring process but that if that proved to be unsafe, Shell would request a permit change. (Shell 10/20/09 Comments). A December 16, 2009 letter from MMS to EPA states that the Alaska Region of MMS does not consider the Discoverer to be an OCS permanently or temporarily attached to the seabed until all anchors have been set because until that time, the Discoverer is operated under, controlled by, and subject to maritime laws and practices (MMS 12/16/09).

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

In light of the regulatory definition of the OCS source, the application of that definition for specific permitted activity as provided in the initial August 2009 proposal, and the comments and additional information received on that issue since the August 2009 proposed permit, EPA is proposing two options for defining when the Discoverer becomes an OCS source in this permit. EPA is specifically requesting comment on which of the following definitions to include in the final permit:[6]

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

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Option 1: Apply the definition of "OCS source" as explained in the August 2009 proposal. Under this approach, the Discoverer would be considered an "OCS source" within the meaning of 40 C.F.R. § 55.2 from the time between the placement of the first anchor on the seabed to the removal of the last anchor from the seabed at a drill site. Once the Discoverer is attached by an anchor to the seabed at a drill site, the Discoverer is at that location for the purpose of exploring, developing or producing resources from the seabed and its activities are more closely aligned with the activities of a stationary source than of a vessel transiting the sea. Under this approach, connection of the Discoverer to the seabed by an anchor at the drill site would be considered both attachment to and erection on the seabed.

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

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

Aside from the supply vessel, none of the other vessels that comprise the Associated Fleet will be physically attached to the Discoverer while the Discoverer is an OCS source and, therefore, none of these other vessels are considered an OCS source for purposes of this permit.[7] The

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

OCS regulations make clear that, although the emissions from a vessel servicing an OCS source and within 25 miles of the OCS Source are considered as direct emissions from the OCS source for purposes of determining the requirements to which the OCS source is subject and in considering the impact from the OCS source, such a vessel is not regulated as an OCS source itself. 57 Fed. Reg. 40792, 40794 (September 4, 1992).

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

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

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

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

Thus, emissions from vessels servicing or associated with an OCS source that are within 25 miles of the OCS source are considered in determining the "potential to emit" or "potential emissions" of the OCS source for purposes of applying the PSD regulations. Emissions from such associated vessels are therefore counted in determining whether the OCS source is required to obtain a PSD permit, as well as in determining the pollutants for which BACT is required and whether emissions from the OCS source cause or contribute to a violation of the NAAQS or applicable increment. 57 Fed. Reg. at 40793-94 ("vessel emissions related to OCS activity will be accounted for by including vessel emissions in the "potential to emit" of an OCS source. Vessel emissions must be included in offset calculations and impact analyses, as required by Section 328 and explained in the NPR."); 56 Fed. Reg. 63,774, 63,777 (Dec. 5, 1991) ("The inclusion of vessel emissions in the total emissions of the stationary source is a statutory requirement under section 328(a)(4)(C). In this manner vessel emissions of attainment pollutants will be accounted for when PSD impact analyses are performed and increment consumption is calculated. For nonattainment pollutants the OCS source will have to obtain offsets as required by the COA, and vessel emissions will be offset.").

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

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

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

In determining the PTE for Shell's Chukchi Sea exploration drilling program, EPA included the potential emissions from the Discoverer while operating as an OCS source, as well as the potential emissions from the Associated Fleet – the ice breaker, the anchor handler/icebreaker, the supply ship, and the OSR fleet – when operating within 25 miles of the Discoverer while the Discoverer is an OCS source.

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

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

Because Shell has applied for a major source permit authorizing operation of the Discoverer and its Associated Fleet at any of Shell's current leases in Lease Sale 193 of the Chukchi Sea, the PTE from the project is calculated based on emissions from any point within the area of operation authorized under the permit during any consecutive 12-month period.

Table 2.1 lists the final PTE for each regulated NSR pollutant from the project, as well as the significant emission rate for each regulated NSR pollutant. Appendix A contains detailed emissions calculations used to determine PTE for emissions of CO, NO_x, $PM_{2.5}$, PM_{10}, SO_2, VOC and lead, the regulated NSR pollutants that are NAAQS pollutants or precursors to NAAQS pollutants and are therefore relevant to the ambient air quality impact analysis discussed in Section 5. The PTE estimates for the remaining regulated NSR pollutants are set forth in Air Sciences 6/16/09; Air Sciences 6/19/09; Air Sciences 6/30/09; Air Sciences 12/18/09-Incinerator; Shell 12/9/09 Supp. App.; Shell 12/13/Supp. App.

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Table 2.1 - Potential to Emit for Regulated NSR Pollutants

Pollutant	Potential to Emit, tpy	Significant Emission Rate, tpy
CO	449	100
NO_x	1188	40
PM	260*	25
$PM_{2.5}$ (precursors NO_x and SO_2)	52	10 (40 for NO_x or SO_2)
PM_{10}	58	15
SO_2	2	40
VOC	87	40
Lead	0.11	0.6
Ozone (precursors VOC and NO_x)	NA	40 for VOC or NO_x
Fluorides	0	3
Sulfuric acid mist	0.404	7
Hydrogen sulfide	0	10
Total reduced sulfur	0	10
Reduced sulfur compounds	0	10
Municipal waste combustor organics	3.26×10^{-7}	3.5×10^{-6}
Municipal waste combustor metals	0.112	15
Municipal waste combustor acid gases	3.59	40
Municipal solid waste landfill emissions	NA	50
Title VI, Class I or II substance	< 1	**

*Emissions of PM have been reduced substantially below this amount as a result of the additional restrictions and controls in this proposed permit that have reduced PM_{10} and $PM2_{2.5}$ emissions, but this estimate for PM has not been recalculated since the August 2009 proposed permit.

** 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 2/24/98; EPA 5/19/98).

Because exploration drilling programs are not included in the list of source categories subject to a 100-tpy applicability threshold, the requirements of the PSD program apply if the project PTE is at least 250 tpy. From Table 2-1, it is evident that Shell's Chukchi exploration drilling program is a major PSD source because emissions of CO and NO_x (and potentially PM) exceed the major source applicability threshold of 250 tpy. In addition, emissions of CO, NO_x, PM, $PM_{2.5}$ (including the precursors NO_x and SO_2), PM_{10}, and ozone precursors (VOC and NO_x) exceed the significant emission rate for each such pollutant. Emissions of SO_2 have been reduced below the significant emission rate as a result of the imposition of BACT on SO_2 emission sources on the Discoverer and Shell's recent request for a limit requiring the use of ultra-low sulfur diesel fuel in the Associated Fleet (discussed in Section 3.3 below). Absent the BACT requirement on SO_2 emission sources on Discoverer, emissions of SO_2 from Shell's exploration drilling program would exceed the significant emission rate. Consequently, pursuant to 40 C.F.R.

§ 52.21(j)(2), Shell is required to apply BACT on the OCS source for CO, NO_x, PM, $PM_{2.5}$ (including the precursors NO_x and SO_2), PM_{10}, SO_2 and ozone precursors (VOC and NO_x). Section 4 contains a discussion of the BACT analysis for each of these pollutants. Additionally, and consistent with 40 C.F.R. §§ 52.21(k) and (m), these potential to emit values are used in the analysis of ambient air quality and demonstration that this source will not cause or contribute to a violation of any NAAQS or PSD increment. Section 5 contains a discussion of the air quality impact analysis.

2.5 Title V

As specified in 40 C.F.R. § 55.13(f)(2), the requirements of the Title V operating permit program, as set forth at 40 C.F.R. Part 71 (Part 71), apply to OCS sources located beyond 25 miles of states' seaward boundaries. 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 as provided in 40 C.F.R. § 71.5(a)(1)(i) within 12 months of first becoming an OCS on Shell's current leases in the Chukchi Sea).

2.6 New Source Performance Standards (NSPS)

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

NSPS IIII, 40 C.F.R. Part 60, Subpart IIII, applies to stationary compression-ignition internal combustion (IC) engines, with the earliest applicability date being for units that were modified, or reconstructed after July 11, 2005 and the applicability date for newly manufactured engines that are not fire-pump engines being April 1, 2006. All diesel engines on board the Discoverer (FD-1 to FD-20), with the exception of the diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19), were manufactured before April 1, 2006 (Air Sciences 7/16/09; Air Sciences 12/10/09), and therefore are not subject to NSPS IIII. The diesel MLC compressor engines (FD-9 to FD-11), and the Caterpillar C7 Logging Winch Engine (FD-19) are Tier 3[8] engines to which NSPS IIII applies.

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

NSPS CCCC, 40 C.F.R. Part 60, Subpart CCCC, applies to commercial and solid waste incinerators (CISWI) constructed after November 30, 1999. The incinerator on board the

[8] 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.

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Discoverer (FD-23) was manufactured after that date and meets the definition of a CISWI. Therefore, it meets the general applicability criteria of NSPS CCCC unless it qualifies for one of the exemptions in 40 C.F.R. § 60.2020. Shell submitted an initial notification and exemption request to EPA as part of its OCS/PSD permit application on the grounds that the incinerator burns more than 30% municipal solid waste and refuse derived fuel and has the capacity to burn less than 35 tons per day of municipal solid waste and refuse derived fuel. See 40 C.F.R. § 60.2020(c)(2). EPA responded in a letter dated January 21, 2009, concurring with Shell's exemption claim and confirming that Shell must maintain records as provided in the exemption in order to continue to qualify for the exemption (EPA 1/21/09 CISWI Letter).

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

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

2.7 National Emission Standards for Hazardous Air Pollutants (NESHAP)

As discussed above, applicable NESHAPs promulgated under Section 112 of the CAA apply to OCS sources if rationally related to the attainment and maintenance of federal and state ambient air quality standards or the requirements of Part C of Title I of the CAA. See 40 C.F.R. § 55.13(e). In addition, the PSD regulations require each major stationary source or major modification to meet applicable standards under 40 C.F.R. Part 61, which are NEHSAPs. See 40 C.F.R. § 52.21(j)(1).

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

After the PSD program regulations were developed, EPA also promulgated Section 112 NESHAP regulations in 40 C.F.R. Part 63. Part 63 NESHAPs apply to a source based on the source category listing, and the regulations generally establish different standards for new and existing sources pursuant to Section 112. In addition, many Part 63 NESHAPs apply only if the affected source is a "major source" as defined in Section 112 and 40 C.F.R. § 63.2. A major source is generally defined as a source that has a PTE of 10 tons per year or more of any single

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"hazardous air pollutant" or "HAP" or 25 tons per year or more of all HAP combined. See Section 112(a)(1) and 40 C.F.R. § 63.2. An "area source" is any source that is not a major source. See Section 112(a)(2) and 40 C.F.R. § 63.2.

Shell has estimated emissions of HAP from Shell's exploration drilling program of 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 2/23/09 Rev. App., 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 C.F.R. Part 63, Subpart ZZZZ. Under that rule, engines at area sources constructed before June 12, 2006 do not have to meet the requirements of 40 C.F.R. Part 63, Subparts A and ZZZZ, including the initial notification, if they fall within 40 C.F.R. § 63.6590(b)(3). See also 40 C.F.R. § 63.6590(a)(1)(iii). Engines FD-1 to FD-8, FD-12 to FD-18, and FD-20 fall within that exemption because they are existing compression-ignition stationary RICE constructed before June 12, 2006. The diesel MLC compressor engines (FD-9 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19) were constructed after June 12, 2006, and therefore qualify as new engines. As provided in 40 C.F.R. § 63.6590(c), however, because these are compression-ignition stationary RICE located at an area source, these emission units comply with Subpart ZZZZ by meeting the requirements of 40 C.F.R. Part 60, Subpart IIII, for compression-ignition engines. As discussed above in Section 2.4, FD-9 to FD-11 and FD-19 are subject to NSPS IIII.

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

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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 C.F.R. §§ 52.21(b)(4) and 55.2. In the case of OCS sources, emissions from vessels servicing or associated with an OCS source are included in the "potential to emit" for an OCS source while physically attached to the OCS source and while en route to or from the source when within 25 miles of the source.

The detailed emissions calculations for the Chukchi Sea exploration drilling program are contained in Appendix A and in Air Sciences 6/16/09; Air Sciences 6/19/09; Air Sciences 6/30/09; Air Sciences 12/18/09-Incinerator; Shell 12/9/09 Supp. App.; Shell 12/13/Supp. App. In developing the emission inventory, EPA relied extensively on emissions data that were representative of the subject emission unit. For most emission units on board the Discoverer, EPA used emissions data from either the manufacturer or from literature that provided equivalent emissions data, such as data from similar emission units. In a very few instances, where representative data were not available, EPA relied on AP-42 to calculate projected emissions (EPA 1995 AP-42 and updates).

The emission inventory reflects application of emission limitations representing best available control technology or "BACT." As discussed in Section 4.1, 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 C.F.R. § 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,[9] 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

[9] See discussion of SO_2 emissions in Section 2.4.3.

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

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

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

The number and range of stack testing of the newer and the smaller internal combustion engines (FD-9 to FD-20) and boilers (FD-21 to FD-22) in this proposed permit has been reduced from the testing required in EPA's initial August 2009 proposed permit. In comments on the August 2009 proposal, Shell requested that stack testing be eliminated entirely for the newer engines, the smaller engines, and the boilers. (Shell 9/17/09 Comments; Shell 11/23/09 Supp. App; Environ 11/25/09). EPA does not agree with Shell that testing these emission units is unnecessary, but believes that testing at a reduced number of operating loads or operating load ranges will continue to provide a reasonable assurance of compliance and accommodate (in part) Shell's concerns regarding the number of required source tests under the permit generally and the difficulty of stack testing some of these specific units due to their unique operation and function. There are no ambient air standards for VOC and predicted impacts of CO from this project are well below the standards. Therefore, EPA focused the monitoring regime on the BACT emission limits for these pollutants. For VOC and CO, testing at lower loads is expected to provide a higher emission factor than testing at full operating loads (see emissions data for various Caterpillar D343 configurations). The same is true with respect to visible emissions. EPA therefore believes that requiring stack testing for VOC, CO and visible emissions within the expected operating range of each engine will provide a reasonable indication of compliance for the VOC, CO, and visible emission limits for the newer engines, the smaller engines, and the boilers. See Permit Conditions F.6, G.8, H.7, I.7, and J.5. Because the data for NOx and particulate matter is less conclusive, EPA is requiring stack testing at two load ranges – a high-load operating range and a lower-load operating range. Shell requested a reduced testing regime only for certain emission units on board the Discoverer, but EPA believes it is appropriate to extend this approach to the engines on board the icebreakers for the same reasons and has done so in this proposed permit. See Conditions N.10.2 and O.12.2.

Shell has provided EPA with information that Shell asserts shows that testing of the deck cranes (Units FD-14 to FD–15) is not practical because of their location on the ship and because of how the engines are loaded. (Shell 9/17/09 Comments; Shell 11/23/09 Supp. App; Environ 11/25/09). While EPA understands that there may be practical challenges to testing these emission units, EPA has insufficient information at this time to eliminate testing for these units. EPA is therefore proposing that, as with the other newer and smaller engines on the Discoverer, that stack testing be required across a fewer number of load ranges. During the public comment period, EPA invites public comment and additional information from Shell and other commenters that further supports or opposes eliminating the stack testing requirement for the deck cranes.

Except for those conditions addressing notification, reporting and testing, the permit conditions contained in Sections B through Q of the proposed permit apply only during the time that the Discoverer is an OCS source. Permit conditions addressing notification, reporting and testing apply at all times as specified. When the Discoverer is an “OCS Source” for purposes of the proposed permit is discussed in Section 2.4.1.

3.2 Generally Applicable Requirements

This section describes the permit conditions that apply generally to the Discoverer and the Associated Fleet and generally relate to permit administration or enforcement.

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

Condition A.2 specifies the enforcement authority for violation of OCS and PSD regulations and this permit, as provided in 40 C.F.R. §§ 55.9(a)-(b) and 52.21. Operation in violation of a permit term or condition is not authorized under this permit.

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 C.F.R. §§ 55.6(a)(4)(iii) and 52.21(r)(3). EPA is aware that Shell is required to obtain approval from other agencies before it is authorized to begin exploratory drilling in the Chukchi Sea and that there is pending litigation regarding the leases under which Shell proposes to conduct its exploratory drilling. EPA believes it is nonetheless appropriate to proceed with issuance of this OCS/PSD permit so that once Shell has all necessary approvals and authorizations to begin its exploratory drilling program on its leases in Lease Area 193, Shell can proceed with its exploratory drilling operations in Lease Area 193 without further delay consistent with a final OCS/PSD permit and all other necessary federal approvals and requirements. Condition A.3 makes clear Shell’s obligation to satisfy all other federal requirements prior to commencing operation under this CAA permit.

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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 C.F.R. § 55.6(a)(4)(iv).

Condition A.5 contains provisions relating to automatic expiration of PSD permits as provided in 40 C.F.R. § 52.21(r)(2) in the event of failing to timely commence or complete construction or of a delay in construction. As provided in 40 C.F.R. § 124.5(g)(2), such permit expiration is not subject to the procedural requirements of 40 C.F.R. Part 124.

Condition A.6 contains provisions for revision, termination, or revocation and reissuance of the permit. Although 40 C.F.R. Part 124 does not contain such procedures for OCS or PSD permits, see 40 C.F.R. § 124.5(g)(1), EPA believes it has inherent authority to revise, terminate, or revoke and reissue a permit for cause, including a material mistake, inaccurate statements made during permit issuance, failure to comply with permit requirements, or ensuring compliance with the requirements of the Clean Air Act. Should EPA decide cause exists to revise, terminate, or revoke and reissue the permit, EPA will follow 40 C.F.R. Part 124. EPA intends to give Shell reasonable notice prior to initiating such action.

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 C.F.R. §§ 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 C.F.R. 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 C.F.R. § 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 C.F.R. § 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 C.F.R. § 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 C.F.R. §§ 71.6(a)(5) and 71.6(a)(6)(iv).

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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 becoming an OCS source at any drill site. This proposed permit authorizes operation of the OCS source at multiple drill site locations on Shell's lease holdings in Lease Area 193 of the Chukchi Sea. The emissions limits and related monitoring, recordkeeping, and reporting apply at all drill site locations. Overall operation as an OCS source under the permit is limited to 168 days per rolling 12-month period. Condition B.1 requires the permittee to notify EPA of the proposed new location and probable duration of a drill site operation as well as to confirm that no Class I area or any area known to have a violation of applicable increment would be impacted by that specific operation.

Condition B.2 limits the annual 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 an annual 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 each year. This is not a continuous 168-day period but an aggregation of all time operating as an OCS source during a given 12-month period. In addition, for each drill site, this condition requires Shell to document the exact location of the Discoverer when drilling, the lease block where drilling is occurring and the duration of the Discoverer as an OCS source at that site. This condition also clarifies that time recorded as an OCS source must include time spent drilling relief wells.

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

Condition B.4 imposes a BACT limit of 0.0015 percent sulfur by weight on the fuel used in the Discoverer engines (except the propulsion engine), boilers, and incinerator. Shell is required to monitor fuel sulfur content by either testing the fuel being used or obtaining supplier certifications from the supplier. Note that Shell has committed to using only ultra-low sulfur diesel in the propulsion engine when operating north of the Bering Strait (Shell 12/9/09 Supp. App.). EPA's authority to impose emission limitations and other operating restrictions on the Discoverer, however, is limited to when the Discoverer is an OCS source.

Condition B.5 limits the fuel sulfur content of fuel used in the Associated Fleet to a sulfur content of 0.0015 percent by weight, which Shell is required to monitor by either testing the fuel being used or obtaining supplier certifications from the supplier. This is a reduction in the permitted fuel sulfur content of fuel used in the Associated Fleet from the initial August 2009 proposed permit of 0.19 percent by weight of sulfur and is based on Shell's commitment to using fuel with a maximum sulfur content of 0.0015 percent sulfur by weight in all engines on vessels in the Associate Fleet when operating north of the Bering Strait (Shell 12/9/09 Supp. App.). The emission inventory, permit limits, and other analyses supporting the proposed permit are based on the use of ultra-low sulfur fuel.

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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 to FD-11) and the Caterpillar C7 Logging Winch Engine (FD-19), be equipped with a closed crankcase ventilation (CCV) system. The MLC Compressor Engines and the Caterpillar C7 Logging Winch Engine have built-in crankcase emission controls.

Condition B.7 contains general testing requirements related to how the stack tests must be conducted. It also contains procedures for approval of an alternative to or a deviation from a reference test method.

Condition B.8 prohibits Shell from flow testing wells, flaring gas, storing liquid hydrocarbons recovered during well testing, or refueling within 25 miles of the Discoverer while the Discoverer is an OCS source. Shell's application states that, during its planned drilling campaign using the Discoverer, they have no plans to conduct these activities. Because EPA has therefore not estimated or analyzed emissions from these activities, Condition B.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 C.F.R. §§ 60.11(e) and 63.6(e).

3.4 Frontier Discoverer Drillship

Sections 3.4 through 3.7 describe each emission unit or group of emission units on the Discoverer and the Associated Fleet in more detail. It also provides additional explanation for the basis for the emissions calculations, explains the BACT or other emission limitations applicable to the emission unit(s), and explains the monitoring, recordkeeping and reporting for the emission unit(s).

The Discoverer is a turret-moored drillship that is able to move under its own power. The propulsion unit will not be used while the drillship is an OCS source (see Section 3.4.2). 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.

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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[b]	Caterpillar C7	250 hp
FD-20	Logging Winch Engine[b]	John Deere PE4020TF270D	35 hp
FD-21 - 22	Heat Boilers	Clayton 200	7.97 MMBtu/hr
FD-23	Incinerator	TeamTec GS500C	276 lb/hr
FD-24 -30	Fuel Tanks	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 will not be used when the Discoverer is an OCS source.

b The engines used to power the logging winch functions are different from the initial August 2009 proposed permit - - the engines were changed at Shell's request, and the necessary changes have been reflected in the emission inventory, the proposed permit, and the other analyses supporting this proposed permit (Air Sciences 12/10/09).

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 to FD-6)

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

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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.

In comments on the initial August 2009 proposed permit, Shell requested that the permit be revised so that compliance with the emission limits applicable to the main generators would be monitored by the electrical power output produced by the generators instead of by monitoring fuel usage as in the initial proposal. (Shell 9/17/09 Comments). Based on supplemental information submitted by Shell (Shell 11/23/09 Supp. App.), EPA believes that monitoring electrical power output produced by the generators will provide a reasonable means of assuring compliance with the applicable emission limits. The main generators comprise six Caterpillar D399 engines rated at 1325 hp each, with an aggregate rating of 7950 hp. Shell has requested a limit to operate at no greater than 71% of this rating, or 5,645 hp. This is equivalent to 4209 kW (mechanical). In Shell's November 23, 2009 submittal, Shell presented generator efficiencies for a variety of gensets, with efficiencies ranging from 92% to 96% (Shell 11/23/09 Supp. App.). Given the apparent age of the Discoverer's gensets and the lack of specific information regarding the efficiencies of the Discoverer's gensets, EPA believes it is appropriate to use the most conservative value (i.e. 92%) to represent generator efficiency for these emission units. This would result in an hourly limit of 3,872 kWe-hr.

Condition C.5 limits the power output in aggregate for these gensets to 3,872 kWe and, in conjunction with the emission factors derived from the stack testing required in Condition C.6, is used to monitor compliance with emission limits for these engines. Condition C.6 requires Shell to conduct stack testing for CO, NO_x, $PM_{2.5,}$ PM10, VOC, ammonia and visible emissions and to monitor certain parameters in addition to determining the efficiency for each engine. In addition to monitoring power output (Condition C.7), Shell is required to monitor and record parameters

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related to good operation of the SCR. Condition C.7.5 requires Shell to monitor and record hourly NO_x emissions.

3.4.2 Propulsion Engine (FD-7)

Section 2.4.1 discusses two alternative approaches for when the Discoverer will be considered an OCS source under the proposed permit. Under both approaches, the propulsion engine will have no emissions during the time the Discoverer drillship is an OCS source.

Based on Shell's application and EPA review, the 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. 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 120 minutes (two hours) at loads up to capacity.

In estimating emissions from this generator, EPA relied upon Caterpillar emissions data from an EPA Health Assessment Document (EPA 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 120 minutes during any single day and 48 hours during any rolling 12-month period. This is an increase in anticipated use and emissions from the August 2009 permit. (Shell 9/17/09 Comments). Fuel limits for the Cementing Units and Logging Winch Engines (FD-16 to FD19) have been decreased to offset the small increase in emissions from the emergency generator. Condition E.2 requires Shell to record all usage of this engine while the Discoverer is an OCS source and, per Condition E.3, to report any deviation from the operational restrictions.

3.4.4 Mud Line Cellar (MLC) Compressor Engines (FD-9 to FD-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

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on operation of all three engines at maximum capacity. The C-15 engines are new and are required to meet EPA's Tier 3 emission standards for nonroad engines (40 C.F.R. § 89.112).[10] The Tier 3 standards have a single limit for NO_x and VOC combined. In the emission inventory, the conservative maximum emission rate of 4.0 g/kW-h was used for each pollutant (i.e. NO_x and VOC). These engines are also subject to a PM limit of .20 g/kW-h under the Tier 3 standards. In the emission inventory, this emission rate of .20 g/kW-h was also used to estimate emissions of PM_{10} and $PM_{2.5,}$ a conservative assumption. Particulate matter emissions are expected to be even lower as a result of the addition of an oxidation catalyst and the passage of the exhaust gases through that system.

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

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

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

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

The proposed permit requires Shell to use a catalytic diesel particulate filter (CDPF) on each engine in this group for control of oxidizable emissions (volatile organics, carbon monoxide, and hydrocarbon particulate matter). The filter vendor Shell is using, CleanAIR Systems, has indicated that with the correct filter on each engine, and with adequate regeneration, the filters are capable of 85% reduction in PM emissions, 90% reduction in CO emissions, and 90% reduction in VOC emissions. (Air Sciences 4/27/09). CleanAIR Systems has also indicated that the exhaust temperature will need to be above 300 degrees Celsius (^{o}C), or 572 degrees

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

Fahrenheit (^oF), 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). (Shell 2/23/09 Rev. App., Appendix F, pp. 173-183).

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

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

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

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

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

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

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

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

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

To estimate emissions from these emission units, EPA relied on the EPA Diesel Health Assessment Document for engine-specific data. (EPA 5/02 Diesel Health Assessment). As noted earlier, this document had several data points for the Detroit 8V-71. All of the "-71" series are from the same family of engines, with a different number of cylinders. In addition, the GM 3-71 engine (FD-18) is manufactured by Detroit Diesel. Accordingly, for the GM 3-71 engine, EPA used the maximum of the data values for each pollutant from any -71 series engine as a conservative assessment of emissions. As also noted before, this document only listed emissions data for PM, not PM_{10} or $PM_{2.5}$. Consequently, the values for PM were assumed to be representative of PM_{10} and $PM_{2.5}$ emission rates, a conservative assumption. Because the logging unit engines are Tier 2 and Tier 3 engines, EPA used the corresponding limits in 40 C.F.R. Part 89 to estimate the PTE from these engines.

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

3.4.8 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 has been determined based on continuous operation for 168 days at full load. Because emissions are based on operation as described above, limitations on fuel usage or hours of operation are unnecessary. Emissions were estimated based on emissions data from the manufacturer. EPA conservatively assumed that all PM_{10} was $PM_{2.5}$.

In addition to the BACT limits in 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 AP-42 and updates) emissions data for a larger class of incinerators because the manufacturer's emissions data is oriented to satisfying European emission standards, and was not in a format that could be converted into a throughput-based emission factor. For emissions of CO, NO_x, VOC and lead, EPA used the worst case emission factor for combustion of domestic waste or sewage. In using this approach, the monitoring regime can be simplified and does not need to require maintaining separate logs for the types of material incinerated.

For emissions of $PM_{2.5}$, PM_{10} and SO_2, Shell requested throughput-based limits. These values are used in the emission inventory, and are reflected in emission limits in the permit (Condition K.5). These limits, expressed in lbs/ton of waste incinerated, do not require additional monitoring because they are the same as the BACT emission limits in the permit (Condition K.1). Shell also requested throughput limits that are below rated capacity in order to demonstrate that they meet NAAQS and increment. These throughput limits and their related PTE limits for NO_x, $PM_{2.5}$ and PM_{10} are contained in Conditions K.6, K.3 and K.4 respectively. In addition to these conditions, the permit also requires stack testing (Condition K.8) and monitoring, recordkeeping and reporting (Condition K.9)

Shell intends to operate the incinerator in coordination with operation of the HPU engines (FD-12 to FD-13) under one of three operating scenarios: Base Operating Scenario, Alternative Operating Scenario #1 and Alternative Operating Scenario #2. Under each of these scenarios, Shell will operate under different daily incineration and fuel limits. Under the Base Operating Scenario, the HPU engines shall not be operated while the incinerator is allowed to incinerate up to 1300 lbs of waste in any calendar day. With Alternative Operating Scenario #1, the HPU engines are allowed to combust up to 352 gallons of fuel per calendar day in both engines in aggregate, while the incinerator is limited to 800 lbs of waste during the same day. Under Alternative Operating Scenario #2, the HPU engines' fuel limit rises to 704 gallons per calendar day in both engines in aggregate, and the incinerator limit is reduced to 300 lbs of waste during the same day. The conditions that establish the alternative operating scenarios for the incinerator are contained in Condition K.7.

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 3-2 lists the tanks on board the Discoverer as well as their respective capacities.

Table 3-2 - Discoverer Diesel Fuel Tanks

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

The fuel stored in the tanks is the diesel used to fuel the emission units on board the Discoverer. Diesel fuel has a very low vapor pressure, and so the tanks will have very low emissions – about 23 lbs of VOC per year (Air Sciences 4/13/09). Consequently, the proposed permit contains no conditions regarding operation of these tanks.

3.4.11 Supply Ship Generator Engine (FD-31)

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

Shell will use a leased vessel to conduct these resupply operations. The most recent plans call for a foreign-flagged vessel named Jim Kilabuk. The Jim Kilabuk will provision out of Canada, and a different vessel would be used if supplied out of Alaska. 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

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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 128 lbs of VOC (Air Sciences 5/4/09; 12/13/09 Supp. App.). 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. 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

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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

Since EPA proposed the initial permit for public comment on August 2009, Shell has revised its approach to the use of icebreaking vessels (Shell 9/17/09 Comments). Icebreakers #1 and #2 no longer have linked operational/emissions limits, and they are no longer interchangeable vessels. Shell’s ice management and anchor handling fleet is still expected to consist of two leased ships: an icebreaker (referred to in the permit as Icebreaker #1) and an anchor handler/icebreaker (referred to in the permit as Icebreaker #2). The purpose of this fleet is to manage the ice in the area of the Discoverer, which involves deflecting or in extreme cases breaking up any ice floes that could impact the ship when it is drilling, and to handle the ship’s anchors during connection to and disconnection from the seabed.

The ice floe frequency and intensity is unpredictable and could range from no ice to ice sufficiently dense that the fleet has insufficient capacity and the Discoverer would need to disconnect from its anchors and move off site. Based on statistics on ice at the Sivulliq drill site

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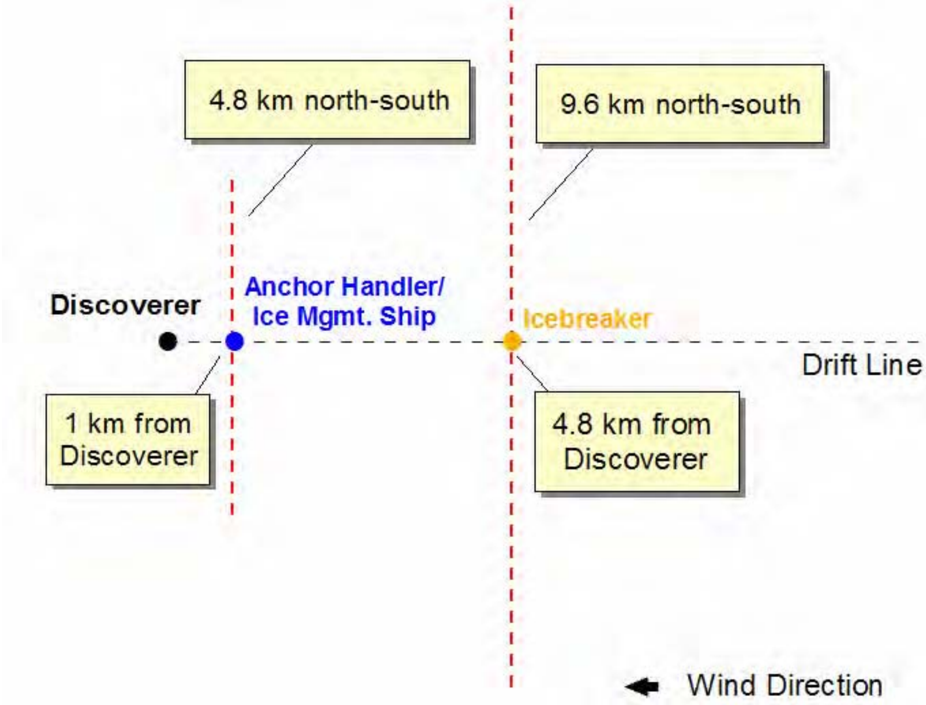
in the Beaufort Sea, Shell estimates that ice breaking capability in its lease holdings in Lease Area 193 in the Chukchi Sea would only be required 38 percent of the time. For the remainder of the time the ice management and anchor handling fleet would be beyond the 25-mile radius from the Discoverer in a warm stack mode (anchored and occupied).

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

Figure 3-1 - Ice management and anchor handling ships locations for breaking of one-year ice



For addressing one-year ice, Icebreaker #1 will typically be positioned from 4,800 meters to 19,000 meters upwind on the drift line and Icebreaker #2 will be located from 1,000 meters to 9,600 meters upwind from the Discoverer. In the case of thick ice, the width of the Icebreaker #1 swath will be about 3 miles (4.8 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 Icebreaker #1 from year to year. Consequently, the vessel used as Icebreaker #1 may change from year to year. In order to accommodate this uncertainty, Shell has requested that the permit allow for a generic Icebreaker #1. Furthermore, the fleet could

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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 Icebreaker #1 that cannot be exceeded for any vessel. Table 3-3 shows the maximum aggregate ratings for each category of equipment for Icebreaker #1.

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

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

To execute Icebreaker #2 duties, Shell will use one of two vessels – either the Tor Viking or a new icebreaker being built to their specifications by Edison Chouest. Each of these vessels will be equipped with SCR on the main engines, which will result in a substantial reduction of NOx. (Shell 9/17/09 Comments). The latter vessel has not been named yet but is referred to by the shipbuilder as Hull 247. Throughout this permit documentation, this vessel is also referred to as Hull 247, with the intent that all permit conditions for Icebreaker #2 continue to apply to the vessel, even once it has had its name changed from Hull 247 to its permanent name. Table 3-4 shows the maximum aggregate ratings for each category of equipment for Icebreaker #2.

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

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

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

In addition, Shell has requested limits on $PM_{2.5}$ of 42.2 lbs/hr and on PM_{10} of 48.0 lbs/hr (Air Sciences 2009b) on Icebreaker #1, and 11.4 lbs/hr and 11.7 lbs/hr, respectively, for Icebreaker #2. 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.

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

Based on Shell's application, there is no scenario where either of the icebreakers is attached to the drillship, thereby becoming part of the OCS source.[11] Consequently, the permit contains Conditions N.8 and O.10 that prohibit such attachment. The permit does allow each icebreaker to approach near the Discoverer for purposes of transferring equipment and crew to and from the Discoverer. Otherwise, Condition N.7 requires Icebreaker #1 to, consistent with the modeling analysis, operate outside of a 4800 meter long cone centered on the centerline of the Discoverer. Similarly, Condition O.7 requires Icebreaker #2 to operate outside of a 1000 meter long cone centered on the centerline of the Discoverer, except during anchor handling operations (Condition O.8) and bow washing (Condition O.9). The air quality impact analysis was based on these operating scenarios and therefore the permit contains emission limits to impose these restrictions. The icebreakers are allowed to transit through their respective cones as these transit events will be of short duration and at low loads as they will not be conducting icebreaking activities within the cones. This is a change from the August 2009 proposed permit. Modeled

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[11] As discussed in Section 2.4.1 above, EPA does not consider Icebreaker #2 to be physicially attached to the Discoverer within the meaning of the definition of "OCS source" in 40 C.F.R. § 55.2 during the time it is assisting the Discoverer in the anchor setting and retrieval process.

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impacts from transit events in the area would therefore be expected to be lower than the worst case scenario.

In order to assure compliance with the emission limits, both icebreakers are required to test their emission sources each drilling season as provided in Conditions N.10 and O.12. Conditions N.11 and O.13 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

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

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
Propulsion Engines	Various	7,200 hp
Generator Engine(s)	Various	584 hp

While the supply ship is in transit, Shell’s application describes operations as consisting of the two propulsion engines operating at no more than 80% 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

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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
Oil Spill Response Main Ship - Nanuq			
N-1 - 2	Propulsion Engines	Caterpillar 3608	2,710 kW
N-3 – 4	Non-propulsion Electrical Generators	Caterpillar 3508	1,285 hp
N-5	Emergency Generator	John Deere	166 kW
N-6	Incinerator	ASC/CP100	125 lbs/hr
Oil Spill Response Work Boat - Kvichak 34-foot No. 1			
K-1 – 2	Propulsion Engines	Cummins QSB	300 hp
K-3	Generator Engines	Various	12 hp
Oil Spill Response Work Boat - Kvichak 34-foot No. 2			
K-4 – 5	Propulsion Engines	Cummins QSB	300 hp
K-6	Generator Engines	Various	12 hp
Oil Spill Response 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.

Since EPA proposed the initial permit for public comment on August 2009, Shell has committed to use of CDPF units from CleanAIR Systems on both the propulsion and non-propulsion generator engines on the Nanuq. Condition Q.1 therefore requires use of the CDPF whenever these engines are operated. The main ambient air impacts from this fleet are annual NO_x. Accordingly, Condition Q.2 imposes an annual NO_x emission limit that results from fuel usage limits requested by Shell. These fuel limits are contained in Condition Q.3. Shell has analyzed operation of the OSR based on certain operational parameters for the fleet. Where these assumptions affect the outcome of the air quality impact analysis, adherence to these parameters is required in Conditions Q.4, Q.5 and Q.6. These conditions require the OSR fleet to operate downwind of the Discoverer and at a minimum distance of 2,000 meters from the Discoverer except in the case of an emergency or to transfer equipment and crew to and from the Discoverer. In addition, the OSR fleet is prohibited from attaching to the Discoverer.

Condition Q.7 requires Shell to stack test the propulsion engines and the generator engines for emissions of NO_x. Condition Q.8 requires the use of fuel flow meters to track fuel usage for these emission units, and has other monitoring requirements to assure compliance with the other permit conditions in Section 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 4/12/09). EPA has determined that permit conditions are not necessary to address these types of activities.

4. BEST AVAILABLE CONTROL TECHNOLOGY

4.1 BACT Applicability and Introduction

Pursuant to 40 C.F.R. § 52.21(j), a new stationary source shall apply BACT for each pollutant subject to regulation under the 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 C.F.R. §52.21(b)(12) in part as

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

The 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.

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

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

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

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

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

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

Step 1 – Identify all available control technologies

Most of the SO_2 emissions for this project result from combustion of diesel fuel which contains some amount of sulfur. Sulfur contained in the material burned in the incinerator also contributes to the SO_2 emissions. The available SO_2 control technologies can be grouped into one of two categories: use of low sulfur fuels and post-combustion treatment of the exhaust gases from the emission units. Shell searched the EPA RACT, BACT, LEAR Clearinghouse (RBLC) and the California BACT Clearinghouse (CA-BACT) for determinations made for SO_2 from the type of emission units on the Discoverer (diesel IC engines, small boilers and the incinerator). The search results are shown in Table 4-4 of the permit application (Shell 2/23/09 Rev. App). The most common control technologies found were "no control" or use of "low sulfur fuel." The only post-combustion SO_2 control technology found was a semi-dry scrubber for an incinerator which was much larger than the incinerator on the Discoverer. The RBLC and CA-BACT did not have any post-combustion control technology applications for diesel IC engines, small boilers, or small incinerators. Several other SO_2 flue gas desulfurization control technologies exist and are used on larger SO_2 sources, such as power plants, petroleum refineries, pulp mills and incinerators, but are not found in practice on smaller emission units such as the boilers and incinerator on the Discoverer.

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Step 2 – Eliminate technically infeasible control options

For technical reasons, EPA believes that post-combustion SO_2 control technologies are not feasible for any of the emission units on the Discoverer, all of which are relatively small emission units. The fact that no post-combustion controls were found in the RBLC search for diesel IC engines, small boilers, and small incinerators indicates that such controls they have not been found to be technically feasible or cost effective for small emission units in past determinations. Moreover, in this case, the emission units are located on a ship with limited space, and the ship will be located in an Arctic environment (low temperatures and limited fresh water availability). Use of ultra-low sulfur diesel fuel (discussed below) results in very low SO_2 emission rates (the table titled "Summary of Annual Emissions" for the Frontier Discoverer Sources in Appendix A, page A-1 shows less than 0.4 ton per year of SO_2 for the sum of all emission units on the Frontier Discoverer). Even if post-combustion SO_2 controls could be engineered to overcome the factors described above, they could not achieve the same degree of SO_2 emissions reduction as the use of 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 as a control technology for the emissions units on the Discover. 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 particulate matter, 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. Because Shell proposed the most effective control option as BACT and there is no evidence that the most effective control option would have adverse environmental impacts, no additional evaluation is required.

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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, we have determined that BACT for SO_2 is the use of ultra low sulfur diesel fuel 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.

Shell submitted additional information to supplement the permit application in a document by Environ International Corp. titled "Diesel Engine Best Available control Technology Analysis" as an attachment to an e-mail dated December 11, 2009 (Environ 12/11/09). One of the engine modification control alternatives included in this document was a cam shaft cylinder reengineering kit, which is available for certain engines.

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%

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to 50% from baseline emissions depending on the specific technology or combination of technologies (Shell 2/23/09 Rev. App.; EPA 9/28/07 Retrofit Strategies; EPA 1995 AP-42 and updates; MassDEP 6/08).

In 1998 EPA set new emission standards for nonroad diesel engines. The rulemaking was part of a 3-tiered progression to lower emission standards. Each tier involves a phase in by horsepower rating over several years. Tier 1 standards for engines over 50 horsepower were phased in from 1996 to 2000. More stringent Tier 2 standards for all engine sizes were phased in from 2001 to 2006, and yet more stringent Tier 3 standards for engines rated over 50 horsepower were phased in from 2006 to 2008 (EPA 8/98 Nonroad Diesel). Depending on the year of manufacture, new diesel IC engines are available that meet the EPA Tier 2 or Tier 3 emission standards. The resulting lower NO_x emission rates for diesel IC engines designed to meet the Tier 2 or Tier 3 standards are the result of the intrinsic engine design features built into them by the manufacturer.

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

In the December 11, 2009 supplement to the BACT analysis, Shell included two additional post-combustion control options for NO_x: Lean NO_x Catalyst (LNC) also know as Hydrocarbon SCR (HC SCR) and NO_x Adsorber technology (Environ 12/11/09). LNC or HC SCR utilize a NO_x reduction catalyst and uses unburned hydrocarbons in the exhaust stream or additional diesel fuel that is injected into the LNC device as the reducing agent to react NO_x to elemental nitrogen. LNC is usually integrated with a catalytic diesel particulate filter (discussed further in Section 4.4) to remove excess hydrocarbons by catalytic reaction to carbon dioxide and water. One manufacture of a LNC system is Clēaire whose LONESTAR™ system for off-road applications is designed to achieve at least 40% NO_x reduction (Clēaire 2009). The California Air Resources Board has verified the Clēaire LONESTAR™ system for certain turbo charged diesel engines but excludes 2-stroke engines, engines with original equipment manufacturers diesel particulate filters and engines with external EGR. NO_x Adsorbers adsorb NO_x by catalytically reacting NO to NO_2 and reacting the NO_2 with a chemical coating on the catalyst matrix to form a nitrate salt. Before the chemical coating becomes saturated, it must be regenerated using a chemical such as hydrogen.

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

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

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

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

Step 2 – Eliminate technically infeasible control options

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

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

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

Step 3 – Rank the remaining technologies by control effectiveness

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

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

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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 6/3/07). 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 C.F.R. § 89.112. For engines ≥750 hp, the Tier 2 emission limit for NO_x + non-methane hydrocarbons (NMHC) is 6.4 g/kW-hr. EPA also promulgated emission standards for new and in-use non-road compression-ignition engines in 40 C.F.R. § 1039. Although these standards for engines ≥750 hp do not apply until model year 2011, the NO_x emission standard for generator sets is 0.67 g/kW-hr. By comparison with these standards, the NO_x emission limit of 0.5 g/kW-hr that EPA is proposing in this permit for the generator diesel IC engines is significantly lower.

Recent permitting actions for IC engines by the Alaska Department of Environmental Conservation have not required NO_x emission limits nearly as low as the 0.5 g/kW-hr emission limit proposed for the Discoverer generator IC engines. For example, the permit for the Nixon Fork Mine issued August 13, 2009 included a generator engine operating at 11.1 g/kW-hr; the permit for the Naknek Power Plant issued March 31, 2009 included a generator engine with an emission rate of 26.0 g/kW-hr; and the Liberty Oil Project (BP) permit issued December 12, 2008 included a generator engine with an emission rate of 6.3 g/kW-hr.

Based on achieving the proposed NO_x emissions limit 0.5 g/kW-hr, the maximum NO_x emissions from each Caterpillar D399 generator engine on the Discoverer would be 1.55 tons per year as shown in Appendix A. 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 4/8/09). In an email to EPA dated April 20, 2009, Shell's environmental consultant provided a response from D.E.C. Marine (Air Sciences 4/20/09). D.E.C. Marine stated that, although the use of engine modifications in addition to the SCR control system would, in theory, result in a lower NO_x emission rate, the engine modifications would have collateral adverse impacts, including increased fuel consumption, lower exhaust gas temperature and increased levels of particulate and hydrocarbon emissions. The surface of the catalyst in the SCR (and the oxidation catalyst) systems would be adversely affected by the higher loading of particulate matter and hydrocarbon emissions and the lower exhaust temperature would reduce the effectiveness of the catalytic reactions in the SCR system. D.E.C. Marine stated that "It is therefore best to optimize the engine for good combustion …….and keeping the temperatures high." D.E.C. Marine also stated that use of the SCR system is a much more effective way to reduce NO_x emissions than using retrofit engine modifications, and that the SCR system is designed with "plenty of margin to make sure we will stay below the guaranteed level of 0.5 g/kW-hr…." EPA agrees that optimizing the engine

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combustion performance in combination with the SCR control system is a preferred strategy for controlling NO_x from the generator engines.

The use of SCR results in low concentrations of ammonia emissions that are not completely reacted in the SCR system. The unreacted ammonia emissions are also known as ammonia slip. In order to ensure that the ammonia slip is maintained at the minimum level commensurate with achieving the NO_x emission limit of 0.5 g/kW-hr, EPA is proposing an emission limit for ammonia as part of the BACT emission limit for NO_x from the generator engines. D.E.C. Marine stated that the SCR system is designed so that ammonia slip is less than 10 ppm; however, they expect that the ammonia slip will actually be less than 3 ppm because the oxidation catalyst that follows the SCR catalyst will oxidize most of the ammonia that passes through the SCR catalyst (Shell 2/23/09 Rev. App., 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 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 (Shell 2/23/09 Rev. App., 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 (Shell 2/23/09 Rev. App., Appendix F, page 195 – 209) is capable of reducing NO_x emissions to as low as 0.1 g/kW-hr under ideal steady state conditions; however, the D.E.C. Marine guarantee is 0.5 g/kW-hr because of the continually varying operating level of the engines and the severe environmental conditions in the Arctic Ocean.

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

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

Based on the facts presented above, EPA is proposing a NO_x emission limit of 0.50 g/kW-hr, in conjunction with an ammonia emission limit of 5 ppm at actual stack gas conditions, as BACT for the Caterpillar D399 generator diesel IC engines based on the use of SCR technology. The

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averaging time and compliance test methods for these emission limits (and the emission limits discussed below) are presented in Section 4.8.

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

Step 2 – Eliminate technically infeasible control options

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

NO_x adsorbers have been used on light duty vehicles; however, Shell stated that they are not aware of any marine applications of this technology. Shell cites one manufacturer, Johnson Matthey, as stating that they are just starting to look at this technology for stationary applications and the technology is not commercially available for stationary applications (Environ 12/11/09). EPA's Office of Transportation and Air Quality has published a summary of potential retrofit technologies for diesel engines which includes NO_x adsorbers (EPA 12/14/09 Potential Retrofit Technologies). However, NO_x adsorbers are not listed on EPA Verified Retrofit Technologies list nor are they listed on the EPA Verified Nonroad Engine Retrofit Technologies List (EPA 12/14/09 Verified Retrofit Technologies; EPA 12/14/09 Nonroad Retrofit Technologies). Since NO_x adsorber technology is not commercially available, EPA considers this technology to be technically infeasible for this application.

LNC has been used in retrofit applications for both on-road and nonroad diesel engines. Example applications include backhoes, graders, loaders and back-up generators; however, neither Shell nor EPA is aware of any marine applications of LNC. A representative of Clēaire, a vendor of LNC technology, stated that there have been few stationary applications of their LNC systems; and although there are no technical reasons the LNC systems would not work, the Clēaire representative stated that their LNC technology would be more of a demonstration project for this application and technical support during the demonstration of this technology would be needed. Therefore, the Clēaire representative would not recommend their LNC technology as commercial for this application (Environ 12/11/09). EPA considers this technology to be technically infeasible for this application.

The compressor diesel IC engines are portable due to critically limited deck space on the Discoverer. The compressor units are designed to be portable so they can be removed from the drill ship at any time should deck space be required for other equipment or materials. However, for operational reasons the preference is to have the compressor units on board the drill ship to

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minimize the time required to set up the units for a second MLC operation if so required. The physical location of the compressor units on the Discoverer is shown in the photograph labeled Figure 3-1 of the December 11, 2009 supplement to the BACT analysis (Environ 12/11/09). As can be seen in the photograph, there is very limited space around the compressor units. Shell provided drawings of the SCR and SCR injection control unit sized for the compressor IC engine. The SCR catalyst unit is approximately 30 inches square and 52 inches flange to flange. Additional space would be required for the piping to connect the SCR catalyst unit to the exhaust pipe from the engine. In addition, the SCR injection control unit has a footprint of about 40 inches by 18 inches and a height of approximately 66 inches. The supply of urea for an SCR system for the compressor engines would require a 1000 gallon storage tank with a deck space requirement of approximately 6.5 by 4 feet and would need to be maintained at a temperature above the "salt out temperature" when urea begins to precipitate from solution. Shell contends that there is not adequate space to install the SCR equipment at the location of the compressor units on the Discoverer and that SCR should therefore be considered technically infeasible for this application.

The State of California typically imposes emission controls that are more stringent than the Federal standards. The California Air Resources Board has created a voluntary Portable Engine Registration Program (PERP), which allows owners and operators to register their portable engines/equipment and operate them throughout the state without obtaining permits from local air districts. The current registration requirements for 2009 and 2010 for engines between 75 and 750 bhp are that these engines must meet the Tier 3 standards. Local air districts in California use the PERP when permitting portable engines including skid mounted engines used on offshore platforms and drilling operations. For example, the Santa Barbara County Air Pollution Control District, which has offshore platforms in its jurisdiction, considers engines meeting the PERP requirements to also meet BACT requirements and does not require additional controls for these engines (Environ 12/11/09). Portable engines such as the compressor IC engines which meet the Tier 3 standards would meet BACT requirement without additional controls under the PERP.

For the reasons discussed above, EPA believes that SCR is not technically feasible for portable deck engines and has excluded SCR from further consideration in the BACT analysis for the compressor diesel IC engines.[12]

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

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

1. Tier 3 Emission Standards of 4.0 g/kWh of NO_x + NMHC

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

2. Tier 2 Emission Standards of 6.4 g/kWh of NO_x + NMHC

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

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

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

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

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

Step 2 – Eliminate technically infeasible control options

The smaller diesel engines on the Discoverer include:

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

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

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

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

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

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

NO_x adsorbers have been used on light duty vehicles; however, Shell stated that they are not aware of any marine applications of this technology. Shell cites one manufacturer, Johnson Matthey as stating that they are just starting to look at this technology for stationary applications and the technology is not commercially available for stationary applications (Environ 12/11/09). EPA's Office of Transportation and Air Quality has published a summary of potential retrofit technologies for diesel engines which includes NO_x adsorbers (EPA 12/14/09 Potential Retrofit Technologies). However, NO_x adsorbers are not listed on EPA Verified Retrofit Technologies list nor are they listed on the EPA Verified Nonroad Engine Retrofit Technologies List (EPA 12/14/09 Verified Retrofit Technologies; EPA 12/14/09 Nonroad Retrofit Technologies). Since NO_x adsorber technology is not commercially available, EPA considers this technology to be technically infeasible for this application.

LNC has been used in retrofit applications for both on-road and nonroad diesel engines. Example applications include backhoes, graders, loaders and back-up generators; however, neither Shell nor EPA is aware of any marine applications of LNC. A representative of Clēaire, a vendor of LNC technology, stated that there have been few stationary applications of their LNC systems; and although there are no technical reasons the LNC systems would not work, the Clēaire representative stated that their LNC technology would be more of a demonstration project for this application and technical support during the demonstration of this technology would be needed. Therefore, the Clēaire representative would not recommend their LNC technology as commercial for this application (Environ 12/11/09).

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

1. The dynamic loading of the smaller engines with short term load swings up to 50 percent can be expected when these engines are operated. The changing load will result in times when the engine load is not sufficient to achieve the exhaust temperatures necessary for optimal performance of the SCR system. Below about 400ºF the NO_x reduction may be as low as 20%. Excessive ammonia slip can occur when the catalyst temperature is not in the optimum range for the reaction between NO_x and ammonia.

2. The smaller engines are located on the topside deck of the ship and exposed to the ambient climatic conditions in the Arctic which will contribute to the difficulty of maintaining proper temperature in the SCR catalyst. The photos in the December 11, 2009 supplement to the BACT analysis shows several of the smaller engine units in Figures 3-1 through 3-6 (Environ 12/11/09).

3. Urea will "salt out" or precipitate from solution at lower temperatures depending on the concentration of urea in the solution. Whether the urea is stored in local tanks at each engine or transferred from a central storage tank, special precautions would be required to ensure that urea did not precipitate.

4. Space on the ship is limited as shown in Figures 3-1 to 3-3 in the December 11, 2009 supplement to the BACT analysis. Several of the smaller engines are "packaged" into enclosed skids which have little or no additional space to accommodate SCR equipment and urea storage tanks without a total redesign of the units.

5. Shell has expressed concern that taking additional deck space for SCR equipment or for urea storage tanks would compromise the maneuverability of equipment needed during drilling.

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

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

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

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

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

The cost of the CCTS engine retrofit cam kits varies by size of the engine, but is relatively low. However, the cost of the kits is not the major cost of the engine rebuild. The major costs are associated with providing the technicians and mechanics to the site to extract the engine and

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shipping the engine to and from the Discoverer and the engine shop where the retrofit kit is installed. The cost of the kit ranges from $4000 to $7500 depending on engine size. The additional cost for logistics and shipping was estimated by Shell to be $50,000 per engine. In the December 11, 2009 supplement to the BACT analysis, Shell estimated the cost effectiveness for the reengineered HPU engines to be $16,202/ton of NO_x reduced and $12, 206/ton of NOx reduced for the reengineered Cementing units (Environ 12/11/09). EPA believes that these cost effectiveness values exceed what is reasonable to be representative of BACT for these engines.

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

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,

- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,

- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

- The manufacturer's recommended operations and scheduled maintenance procedures must be followed for each emission unit.

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

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

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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	15.717
FD – 19 Logging Unit Winch Engine	4.0
FD-20, Logging Unit Generator Engine	7.50

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

Step 2 – Eliminate technically infeasible control options

The Discoverer has two small diesel fueled boilers (FD-21 and FD-22) to provide heat for domestic and work spaces. According to Shell's application, under typical operations, one boiler will be operating and the second will be on standby, although there may be times when both boilers operate simultaneously. The maximum heat input for each of the existing Clayton Model 200 boilers is approximately 8 million Btu per hour (MMBtu/hr). As shown in Appendix A, the total estimated emissions of NO_x from the two boilers are 6.46 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 2/23/09 Rev. App., 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 (Shell 2/23/09 Rev. App., 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.

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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 at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

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

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

4.3.5 NO_x BACT for the Incinerator (FD-23)

Step 2 – Eliminate technically infeasible control options

The Discoverer has a two-stage, batch charged incinerator capable of incinerating 276 pounds per hour of solid trash, or 6624 pounds per day; however, Shell has requested an operating restriction to limit the maximum amount of trash burned to no more than 1300 pounds per day. The maximum incineration capacity is rated at 3 MMBtu/hr. The use rate and batch size will be variable depending on the waste generation rate on board the Discoverer. The only

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determination for post-combustion controls for NO_x found in the EPA RBLC and CA-BACT searches was for selective non-catalytic reduction (SNCR), although that determination was for a much larger incinerator. Team Tec, the manufacturer of the incinerator on the Discoverer, was not aware of any control technologies that have been installed on this model of incinerator for control of NO_x (Shell 2/23/09 Rev. App., 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 infeasible. Therefore, EPA believes that SNCR is technically infeasible for this small incinerator.

Step 3 – Rank the remaining technologies by control effectiveness

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

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

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

Step 5 – Select 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 at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

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

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

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

Step 1 – Identify all available control technologies

PM/PM_{10}/$PM_{2.5}$ emissions (hereafter referred to as particulate matter or PM[13]) 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 12/14/09 Verified Retrofit Technologies), and with the control technologies discussed in the Western Regional Air Partnership "Offroad Diesel Retrofit Guidance Document" (WRAP 11/28/05) and the Massachusetts Department of Environmental Protection "Diesel Engine Retrofits in the Construction Industry: A How To Guide" (MassDEP 6/08).

LSF reduces the sulfate PM fraction by limiting the amount of sulfur in the fuel that is available for sulfate formation. As described in Section 4.2, use of ultra-low sulfur was determined to represent BACT for SO_2 and has the added benefit of reducing the sulfate portion of PM emissions from emission units burning diesel fuel. An OxyCat removes the SOF of PM through catalytic oxidation of the combustible organic matter resulting in an overall PM control efficiency of about 50 percent. A DPF removes the insoluble fraction of PM (soot) by filtration with an overall PM control efficiency of 40 to 50 percent. CDPF technology removes both the SOF and the insoluble fraction of PM with an overall PM control efficiency of about 85 percent. According to information from CleanAIR Systems, a CDPF vendor, the CDPF must be operated at temperatures greater than 300ºC (572ºF) for a certain percentage of the operating time for proper filter regeneration when using low sulfur fuel (Shell 2/23/09 Rev. App., Appendix F,

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

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 to FD-11) will be equipped with a CCV system. The MLC Compressor engines have built-in crankcase emission control.

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than an applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. 40 C.F.R. § 52.21(b)(12)(definition of BACT). EPA has promulgated exhaust emission standards for stationary IC engines under the NSPS Subpart IIII which specifies that engine manufacturers must certify their 2007 and later engines to the applicable emission standard for new nonroad engines in 40 C.F.R. § 89.112 (and several other sections). 40 C.F.R. § 60.4201(a). Engines designed to meet Tier 2 or Tier 3 PM emission standards typically employ a combination of low PM emitting engine designs and DPF or CDPF. For diesel IC engines manufactured to meet the Tier 3 emission standards such as the three 540 hp MLC compressor engines (FD-9 to FD-11) and the 250 hp Logging Unit Winch engine (FD-19), the applicable PM emission standard is 0.2 grams per kilowatt hour (g/kW-hr). 40 C.F.R. § 89.112(a) Table 1.

No PM control technologies were found from the search of the RBLC and CA-BACT for diesel fired boilers less than or equal to 100 MMBtu/hr. Although not found in the previous determinations listed in the RBLC and CA-BACT, PM control technologies such as an electrostatic precipitator (ESP) or a fabric filter could theoretically be designed for the small boilers on the Discoverer.

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

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

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

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

Exhibit 5
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The available control technologies for the Discoverer's diesel IC engines are LSF, OxyCat, DPF, CDPF, Tier 2 or 3 level controls, and CCV. Tier 2 or Tier 3 level controls are intrinsic to the original engine design; and, therefore, are not considered technically feasible in this case since they are not part of the design of the existing Caterpillar D399 diesel engines.

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

The higher pressure drop of the CDPF is of concern because, as described in Section 4.3.1, the generator diesel IC engines will be equipped with the SCR system for NO_x control. The SCR catalyst imposes a backpressure on the engines due to the pressure drop required to move the exhaust gases through the SCR catalyst matrix. Adding the additional pressure drop associated with a CDPF could result in an excessive backpressure on the engines. D.E.C. Marine addressed the possibility of designing a CDPF to be used with the SCR system (Shell 2/23/09 Rev. App., Appendix F, Footnote 41, page 113). Since a CDPF has not been included with the vendor's SCR systems in the past, a feasibility study would have to be conducted before final design. Several considerations would have to be addressed including the additional cross-sectional area needed for the CDPF catalyst matrix (perhaps as much as 50% 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.[14]

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

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.

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

[14] 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). This cost effectivness value exceeds what EPA believes to be representaitve of BAC for these engines.

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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 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 2/23/09 Rev. App., Appendix F, Footnote 47, pages 151 to 166 of the permit application.

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

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

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

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

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

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

The compressor diesel IC engines and the Logging Unit Winch engine are newer and meet the EPA Tier 3 emission standards. According to the literature describing the Caterpillar C-15 engines, part of the control technology used on the C-15 engine includes clean gas induction which consists of a DPF and EGR (Shell 2/23/09 Rev. App, Appendix F, footnote 36, pages 94

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to 99). Therefore, the C-15 engines include the same type of diesel particulate filtration as achieved with a CDPF. The Tier 3 standard for PM is 0.2 g/kW-hr. Additional add-on PM control devices could be used, such as a CDPF, an OxyCat system or a DPF in series with the integral controls on the Tier 3 engines.

Step 3 – Rank the remaining technologies by control effectiveness

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

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

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

In the December 11, 2009 supplement to the BACT analysis, Shell included a cost effectiveness calculation for a CDPF for the Compressor engines and the Logging Unit Winch engine (Environ 12/11/09). The calculated cost effectiveness value was $41,883/ton of PM removed for a CDPF on a compressor engine and $90,467/ton of PM removed for a CDPF on the Logging Unit Winch engine. Since the cost effectiveness values estimated for the CDPF on the Tier 3 engines are much greater than $10,000/ton commonly considered high for stationary source BACT determinations, EPA proposes that use of a CDPF does not represent BACT for the Tier 3 engines.

In the December 11, 2009 supplement to the BACT analysis, Shell included a cost effectiveness calculation for an OxyCat system for the compressor engines and the Logging Unit Winch engine (Environ 12/11/09). The calculated cost effectiveness value was $32,139/ton of PM removed for an OxyCat system on a compressor engine and $55,233/ton of PM removed for an OxyCat system on the Logging Unit Winch engine. As in the case of the CDPF discussed above, the cost effectiveness values for an OxyCat system are higher than EPA considers reasonable for a BACT determination.

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

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

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

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

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,

- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,

- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

- The manufacturer's recommended operations and scheduled maintenance procedures must be followed for each emission unit.

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

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

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

<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. These control technologies are not technically feasible because they are not part of the design of the Discoverer's smaller diesel IC engines. LSF, OxyCat, DPF, and CDPF are all considered technically feasible for the smaller diesel IC engines.

<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:

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

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

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

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

Step 5 – Select PM BACT for the Smaller Diesel Engines

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

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

Emission Unit Number and Engine Name	PM Emission Limit (g/kW-hr)
FD-12 & 13, HPU Engines	0.253
FD-14 & 15, Deck Crane Engines	0.0715
FD-16 & 17, Cementing Unit Engines	0.253
FD-18 Cementing Unit	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 a work practice consisting of installation of CCV for all smaller diesel IC engines except for the MLC Compressor engines (FD 9 to FD-11) and the Logging Unit Winch Engine (FD-19), which have built-in crankcase emission control.

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

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

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

Step 2 – Eliminate technically infeasible control options

No PM controls were found in the RBLC or CA-BACT search for small boilers.[15] Although it may be theoretically possible to design an ESP or a fabric filter for the small boilers on the Discoverer, one factor limiting the application of a fabric filter or an ESP on these boilers is that more than 50 percent of the PM from diesel fired boilers is condensable PM which would not be collected in a fabric filter or ESP at normal exhaust gas temperatures. As shown in Appendix A, the PM emissions for each boiler are 0.38 ton per year. Based on these factors, EPA considers a fabric filter or an ESP to be technically infeasible for control of PM from the boilers on the Discoverer. The use of ultra-low sulfur fuel for combustion will minimize the sulfate fraction of the PM emissions.

Step 3 – Rank the remaining technologies by control effectiveness

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

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

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

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

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

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,

[15] 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.

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• At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,

• Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

• The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

• The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

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

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

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

4.4.5 PM BACT for the Incinerator (FD-23)

Step 2 – Eliminate technically infeasible control options

Based on review of the RBLC and CA-BACT, the available control technologies for the Discoverer's incinerator (FD-23) are an ESP and good combustion practices. The incinerator listed in the RBLC with an ESP was rated at 350 tons per day (29,167 lb/hr), which is over 100 times the size of the incinerator on the Discoverer. Communication with TeamTec, the manufacturer of the incinerator on the Discoverer, indicated that they were not aware of any control technologies that have been installed on this model of incinerator for control of any of the pollutants including PM (Shell 2/23/09 Rev. App., Appendix F, Footnote 39, pages 105 to 112).

By letter to EPA dated December 13, 2009, Shell provided a study conducted by GI Development LLC to evaluate PM control options for the incinerator (Shell 12/13/09 Supp. App.). The GI Development LLC study evaluated a dry ESP, a wet ESP, a venturi scrubber and a ceramic fiber baghouse.

Step 3 – Rank the remaining technologies by control effectiveness

1. Ceramic fabric baghouse – 99 percent control
2. Venturi scrubber – 90 percent control

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3. Dry ESP – 75 percent control at the quoted size
4. Wet ESP – 75 percent control at the quoted size
5. Good combustion practices.

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

The cost effectiveness value for the ceramic fiber baghouse based on a capital equipment cost of $230,000 was calculated to be $65,986/ton of PM removed. The high cost effectiveness value was due to both the high capital cost and the relatively low amount of potential PM removed (about 0.5 ton/year). This cost effectiveness value is higher than EPA considers reasonable for a BACT determination. Therefore, the ceramic fabric baghouse control device was eliminated from consideration in the BACT process.

The cost effectiveness value for the venturi scrubber based on a capital equipment cost of $150,000 was calculated to be $49,490/ton of PM removed. The high cost effectiveness value was due to both the high capital cost and the relatively low amount of potential PM removed (about 0.5 ton/year). This cost effectiveness value is higher than EPA considers reasonable for a BACT determination. Therefore, the venturi scrubber control device was eliminated from consideration in the BACT process.

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

The remaining control option is good combustion practices.

Step 5 – Select PM BACT for the Incinerator

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

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,

- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,

- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

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• The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

• The manufacturer's recommended scheduled operation and maintenance procedures must be followed for each emission unit.

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

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

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

4.5 CO and VOC BACT Analysis

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

Step 1 – Identify all available control technologies

The available CO and VOC control technologies for the Discoverer's engines, boilers, and incinerator were determined from searches performed on the RBLC and the CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-7 of the permit application. Crankcase ventilation gases from the diesel engines contain some VOC. CCV eliminates emissions from crankcase blow-by by directing these gases back to the intake manifold of the engine so they can be combusted.

The available CO and VOC combustion control technologies for diesel IC engines identified in the RBLC and CA-BACT are OxyCat and Tier 2 or Tier 3 diesel engine standards. OxyCat reduces CO/VOC emission through catalytic oxidation of these combustible gases. The OxyCat control system proposed for the generator diesel IC engines (and discussed in the Section 4.4.1 above) will provide an overall control efficiency of 80 percent for CO and approximately 70 percent for VOC according to D.E.C. Marine, the OxyCat vendor for the Discoverer's generator diesel IC engines (Shell 2/23/09 Rev. App., 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 (Air Sciences 4/27/09).

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

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that pollutant is applicable to the source. 40 C.F.R. § 52.21(b)(12)(definition of BACT). EPA has promulgated exhaust emission standards for stationary IC engines under the NSPS Subpart IIII which specifies that engine manufacturers must certify their 2007 and later engines to the applicable emission standard for new nonroad engines in 40 C.F.R. § 89.112 (and several other sections). 40C.F.R. § 60.4201(a). Engines designed to meet Tier 2 or Tier 3 PM emission standards typically employ a combination of low PM emitting engine designs and DPF or CDPF. For diesel IC engines manufactured to meet the Tier 3 emission standards such as the three 540 hp MLC compressor engines (FD-9 to FD-11) and the 250 hp Logging Unit Winch engine (FD-19), the applicable CO emission standard is 3.5 grams per kilowatt hour (g/kW-hr). 40 C.F.R. § 89.112(a) Table 1. The VOC emission limit for Tier 3 engines is expressed as a combined value with NO_x (4.0 g/kW-hr).

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

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

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

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 2/23/09 Rev. App., 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

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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.[16]

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 design proposed by D.E.C. Marine incorporates oxidation catalyst downstream of the SCR catalyst in the same converter shell, which results in a more compact and economical system than having separate devices. The OxyCat system is expected to reduce CO emissions to <0.179 g/kW-hr and VOC emissions to <0.0229 g/kW-hr.

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

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

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

[16] 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 Shell 2/23/09 Rev. App. 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. These cost effectiveness values exceed what EPA believes is representative of BACT for these engines.

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

Step 2 – Eliminate technically infeasible control options

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

Step 3 – Rank the remaining technologies by control effectiveness

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

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

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

On December 22, 2009, Shell submitted CO cost effectiveness calculations for CDPF and Oxy Cat controls for the compressor engines and the Logging Unit Winch engine (Environ 212/22/09). The cost effectiveness value for a CDPF for each of the compressor engines was calculated to be $9,848/ton of CO removed. The cost effectiveness value for an OxyCat for each of the compressor engines was calculated to be $4,323/ton of CO removed. The cost effectiveness values were calculated assuming the baseline emission rate was equal to the Tier 3 CO engine standard of 3.5 g/kW-hr. Since the cost effectiveness value for the CDPF was near the high end of the range that EPA considers reasonable, the incremental cost effectiveness value between an OxyCat and a CDPF was evaluated to determine whether the additional cost to move from an OxyCat to a CDPF for the compressor engines was justified. The incremental cost effectiveness value was calculated to be $17,700/ton of CO removed. Because the incremental cost effectiveness value between an OxyCat and a CDPF is so large, EPA proposes that an OxyCat is representative of BACT for the compressor engines.

In the December 22, 2009 analysis, the cost effectiveness values for a CDPF and an OxyCat for the Logging Unit Winch engine were calculated (Environ 12/22/09). The cost effectiveness value for a CDPF for the Logging Unit Winch engine was calculated to be $3,329/ton of CO removed, a cost effectiveness value that EPA considers reasonable. Therefore, EPA proposes that a CDPF is representative of BACT for the Logging Unit Winch engine.

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

EPA proposes that BACT for CO from the compressor diesel IC engines is an emission limit of 1.86 g/kW-hr based on the use of an OxyCat. EPA proposes that BACT for CO from the Logging Unit Winch diesel IC engine is an emission limit of 0.70 g/kW-hr based on the use of a

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CDPF. For these Tier 3 engines, the VOC emissions are included in determining compliance with the NO_x emission limit described in Section 4.3.2.

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

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

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

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

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.

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

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

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

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

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

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

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.

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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 Engine	0.270	0.880
FD-20, Logging Unit Generator Engine	0.750	0.550

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

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

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

Step 2 – Eliminate technically infeasible control options

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

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

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

- Operating personnel must be trained to identify signs of improper operation and maintenance, including visible plumes, and instructed to report these to the maintenance specialist,

- At least one full-time equipment maintenance specialist must be on board at all times during drilling activities,

- Each emission unit must be inspected by the maintenance specialist at least once a week for proper operation and maintenance consistent with the manufacturer's recommendations,

- The operation and maintenance manual provided by the manufacturer for each emission unit must be maintained on board the Discoverer at all times,

- The manufacturer's recommended operation and scheduled maintenance procedures must be followed for each emission unit.

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

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

Table 4-4 - CO and VOC Emission Limits for the 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

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

In the letter to EPA dated December 13, 2009, Shell provided additional explanation for the VOC estimate from de-gassing of drilling mud that was originally provided in its May 4, 2009 submission to EPA (Shell 12/13/09 Supp. App.). The VOC emission estimate based on the possibility of drilling a maximum of four wells per year was 128 pounds of VOC per year.

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

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

In Attachment D of the December 13, 2009 letter to EPA, Shell provided cost information for a flare based on information from the EPA Air Pollution Cost Control Manual (Shell 12/13/09 Supp. App). The annualized cost for a small flare (2 inch diameter nozzle) from Table 2.13 of the EPA Air Pollution Cost Control Manual was $61,800. This annualized cost value is likely an underestimate of the cost as applied to Shell's operation since it was for an on-land flare which is less expensive to construct compared to an on-ship flare system and was based on 2002 dollars. However, using the annualized cost of $61,800, the cost effectiveness value for controlling 128 pounds of VOC per year was calculated to be $965,625/ton of VOC removed (assuming 100 percent destruction of the VOC in the flare). A cost effectiveness value of this magnitude is much higher than EPA considers reasonable for a BACT determination. Therefore, EPA proposes that BACT for the mud de-gassing operation on the Discoverer is the use of the existing equipment.

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

Aside from the supply vessel, the vessels in the Associated Fleet will not be physically attached to the Discover, and therefore will not be part of the OCS source and not subject to the BACT requirement. The supply vessel will be part of the OCS source and thus subject to BACT only

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for the relatively short period of time it will be tied to the Discoverer. Shell estimated a maximum of eight resupply events per year. When the supplies are delivered to the Discoverer, the supply vessel would be attached to the Discoverer for a maximum of 12 hours with one generator diesel engine of less than 300 horsepower operating. The maximum time a supply vessel would be attached to the Discoverer and thus considered part of the "OCS source" would be 96 hours for the drilling season. The estimated emissions from the supply vessel while tied to the Discoverer based on the maximum time of 96 hours are shown in Appendix A. The largest value is 0.43 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 0.0002 for SO_2. Because of the very small emission reduction potential and the short time period over which any control technology would be amortized, EPA believes that installation of any additional control technology on the supply vessels would not be cost effective. In the December 11, 2009 supplement to the BACT analysis, Shell provided cost effectiveness calculations for several control alternatives that could be applied to the generator engine on the supply vessel (Environ 12/11/09). In all cases the calculated cost effectiveness values were much greater than EPA considers reasonable for BACT determinations. For example, the calculated cost effectiveness values for the supply vessel generator engine were approximately: $187,000/ton of PM for a CDPF; $114,000/ton of PM for an OxyCat; and $228,000/ton of PM for a DPF. These cost effectiveness values are much greater that EPA considers reasonable within the context of a BACT determination. Thus, EPA proposes that BACT for the supply vessel is no additional add-on controls. Shell has agreed, and the permit proposes, that Shell use ultra-low sulfur diesel fuel in all vessels in the Associated Fleet, including the supply vessel to assure attainment of the NAAQS and compliance with increment.

4.8 Reference Test Methods

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

EPA is proposing that BACT for SO_2 is the use of 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 C.F.R. § 80.330(b). Any test method for determining the sulfur content of diesel fuel must satisfy the EPA approval process contained in 40 C.F.R. § 80.585(a) and the precision and accuracy requirements of 40 C.F.R. § 80.584. As an alternative, the sulfur content of the diesel fuel may be determined using ASTM D 5453-09. The permit specifies the frequency of the required testing, which is discussed in Section 3. 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.

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

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

Except for the incinerator, $PM_{2.5,}$ PM_{10} and $PM_{2.5}$ emissions shall be measured using EPA Method 201/201A and Other Test Method 28 (OTM 28). Once proposed revisions to EPA Method 202 are finalized, see 56 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 proposed in 56 Fed. Reg. 12970 (March 25, 2009), at which time $PM_{2.5}$ emissions from the incinerator will be measured using the revised EPA Methods 201/201A and 202.

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

EPA Methods 1, 2, 3A, 3B, 4 and 19 shall be used as needed to convert the measured NO_x, PM, PM_{10}, $PM_{2.5}$ and CO emissions into units of the emission limits in the permit. The EPA Methods identified in this section can be found in 40 C.F.R. Part 60, Appendix A, in 40 C.F.R. Part 51, Appendix M or on the EPA Emission Measurement Center webpage http://www.epa.gov/ttn/emc/. Permit Condition B.7.11contains procedures for Shell to request and for EPA to approve alternatives to or deviations from the referenced test methods.

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5. AIR QUALITY IMPACT ANALYSIS

5.1 Required Analyses

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

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

The "maximum allowable increases," also known as PSD increments, are listed in 40 C.F.R. § 52.21(c). There are PSD 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 C.F.R. § 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. As discussed below, the area covered by Shell's leases in Lease Sale 193 is a Class II area. See CAA Section 162(b). No areas have been redesignated to Class III that might be impacted by this project. The NAAQS and PSD Class I and II increments are listed in the Table 5-1.

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Table 5-1 – 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
Hydrogen Sulfide (H_2S)	1-Hour						0.2
Reduced Sulfur Compounds	1-Hour						10

a. Reference: 40 C.F.R. Part 50
b. Reference: 40 C.F.R. Part 52.21(c)
c. Reference: EPA 5/87 Ambient Monitoring Guidelines; EPA 10/90 Draft NSR Manual
d. Units in parts per million (ppm)

e. No monitoring threshold level. However, if the net emissions increase of NO_2 or VOC is 100 tons per year or more, the PSD regulation requires an ambient air quality impact analysis including an ozone data collection program. 40 C.F.R. § 52.21(i)(5).
f. 2008 standard
g. 1997 standard

40 C.F.R. § 52.21(m) requires a PSD permit application to include an air quality analysis in connection with the demonstration required by 40 C.F.R. § 52.21(k). For each pollutant for which a NAAQS or PSD increment exists, 40 C.F.R. § 52.21(m)(1)(iv) requires the analysis to include at least one year of pre-construction ambient air quality monitoring data, unless EPA approves a shorter monitoring period (not less than four months). 40 C.F.R. § 52.21(i)(5)(i) allows exemption from the requirement for pre-construction ambient monitoring if the net emissions increase of a pollutant from the proposed source or modification would cause air quality impact less than the ambient monitoring thresholds listed in 40 C.F.R. § 52.21(i)(5)(i), which are also listed in Table 5-1. For each pollutant for which no NAAQS has been established, 40 C.F.R. § 52.21(m)(1)(ii) allows EPA to require monitoring as determined to be necessary to assess ambient air quality for that pollutant in the area. In addition, 40 C.F.R. § 52.21(m)(2) authorizes EPA to require post-construction ambient air quality monitoring if EPA determines it is necessary to determine the effect that emissions from the source or modification may have on air quality.

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

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

5.2 NAAQS and Increment Analysis

The air quality analysis for NAAQS and increment compliance for Shell's exploratory drilling program was conducted in two basic stages. First, Shell conducted a screening analysis to determine the pollutants for which the project exceeded the significant impact levels and for which a more robust air quality demonstration would be required. EPA guidance calls for 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 5-1 (EPA 5/87 Ambient Monitoring Guidelines; EPA 10/90 Draft NSR Manual). As shown in Table 5-2, the highest concentration impact from the Discoverer and the Associated Fleet predicted by the screening analysis for the applicable averaging time exceeded the significant impact levels for 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

C.F.R. § 52.21(i)(5). In addition, because EPA has not promulgated a $PM_{2.5}$ significant impact level, a NAAQS analysis is required for this air pollutant.

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 C.F.R. 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. Figure 5-1 shows the significant impact areas for the Shell Chukchi Sea OCS leases.

Table 5-2 – Class II Area Significant Impact Levels and Radius

Air Pollutant	Averaging Time	Predicted ($\mu g/m^3$)	Level ($\mu g/m^3$)	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 5/29/09 Supp. App.
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 NO_x and VOC emissions exceed 100 tons per year. As a result, Shell is required to conduct an ozone analysis, including data collection. See Section 3 and Appendix A for emission calculations.

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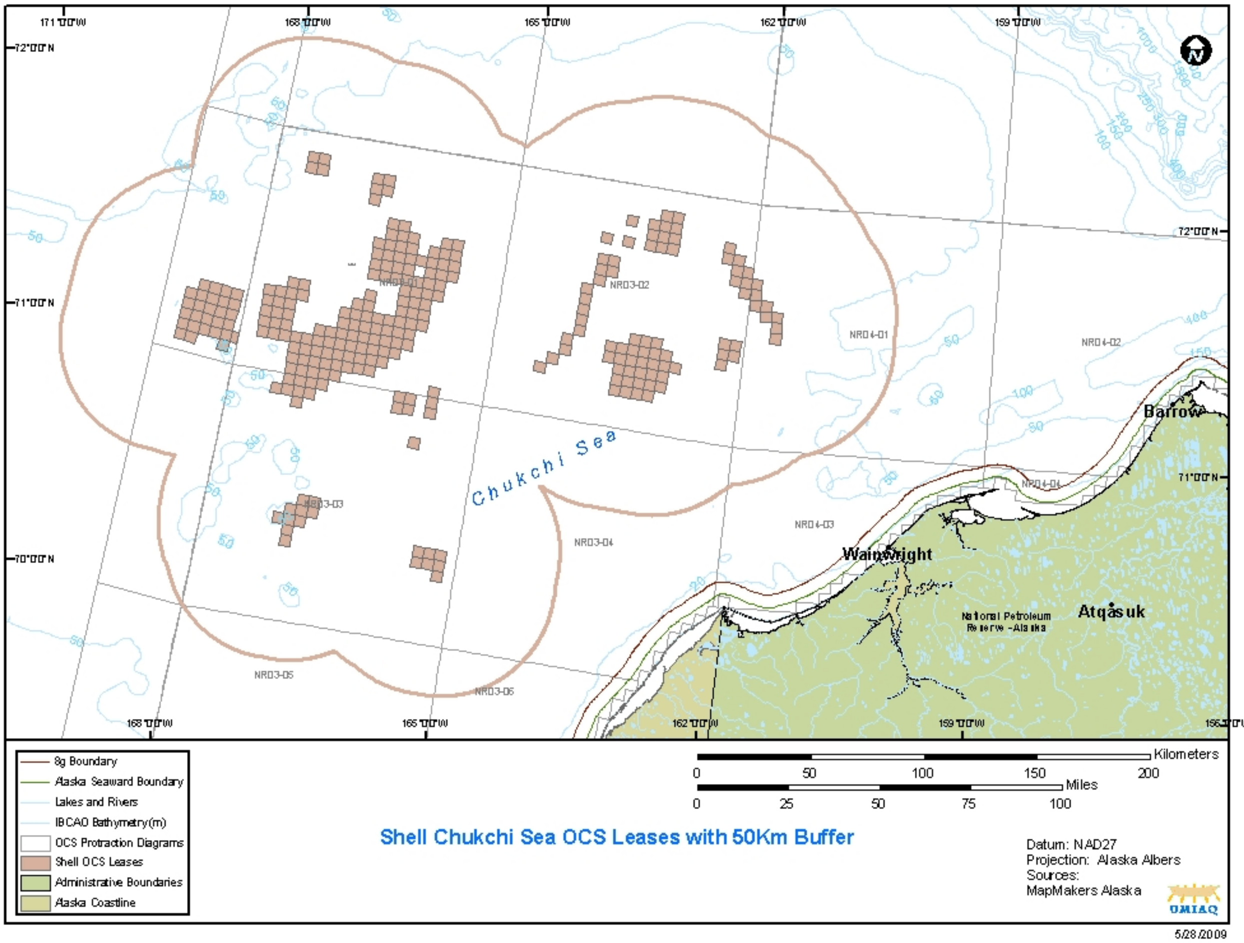
Figure 5-1 – Chukchi Sea OCS Leases and Significant Impact Areas



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 C.F.R. § 52.21 to be the area bounded on the shoreward side by a parallel line 25 miles from the State's seaward boundary; on the seaward side by the boundary of U.S. territorial waters; and on the other two sides by the seaward extension of the onshore Air Quality Control Region (AQCR) boundaries (EPA 7/2/09 Baseline Memo).

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 C.F.R. § 52.21(b)(14)(i), and the trigger dates for SO_2, NO_2, and PM_{10} for this baseline area are shown in Table 5.3 below.

Table 5.3 – Major Source Baseline Dates

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

The minor source baseline date is established in an area when the first complete PSD application is submitted to EPA after the trigger date. See 40 C.F.R. § 52.21(b)(14)(i). EPA deemed the Shell OCS/PSD application for exploratory drilling in the Chukchi Sea complete on July 31, 2009 (EPA 7/31/09 Completeness Letter), which effectively establishes July 31, 2009 as the minor source baseline date for SO_2, NO_2, and PM_{10} in the Chukchi Sea/Beaufort Sea baseline area. As a result, Shell is required to consider increment consuming emissions increases and decreases after July 31, 2009 from other sources in the area in its analysis of compliance with air quality increments. 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 C.F.R. § 52.21(b)(13), 40 C.F.R. § 52.21(k)(1) and EPA 10/90 Draft NSR Manual.

As discussed in section 5.2.4 below, Shell anticipates constructing a warehouse which would have 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 as shown in Table 5.4 below (Schuler 7/2/09).

Table 5.4 – Minor Source Baseline Date

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

5.2.3 Air Quality Model

In its air quality analysis, Shell used a non-guideline model called ISC3-Prime (EPA 2004 ISC3-Prime) 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 (EPA 6/03 AERMOD). In the absence of the site-specific, over-ocean meteorological data necessary to run other models, 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 C.F.R. Part 51, Appendix W for use in evaluating Shell's permit application and air impact analysis. As provided in 40 C.F.R. § 52.21(l)(2), EPA is requesting public comment on the suitability of 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 (with two alternatives to one of the primary operating scenarios) and eleven secondary operating scenarios to analyze in determining air quality impacts (summarized in Table 5-5).[17] 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 (Shell 12/18/08 App; Shell 2/23/09 Rev. App.; Shell 5/29/09 Supp. App; Shell 9/17/09 Comments). 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 (POS #1) and the continuous over land operation of an oil fired heater located in a warehouse at an undermined site on-shore (POS #2). The two alternatives to the first primary operating scenario involve different levels of usage of the Discoverer incinerator and HPU units. Secondary operating scenarios (SOS #1 to #11) basically consist 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 1978. The modeling analysis used actual dimensions of the structures that cause wake effects, which is a more conservative modeling approach.

[17] Shell submitted modeling analyses in support of the August 2009 proposed permit, and provided a supplemental analysis of POS# 1 and two alterantives to POS#1 on September 17, 2009 (Shell 9/17/09 Comments).

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Table 5-5 – Primary and Secondary Operating Scenarios

Operating Scenario	No.	Description
Primary	1	Drilling by the Discoverer, and deployment of the ice breaker and oil spill response fleets (including two alternatives)
	2	Associated Growth (land based combustion source).
Secondary	1	Discoverer bow ice removal by Ice Breaker #2 concurrent with POS #1.
	2	Supply ship transit concurrent with POS #1.
	3	Discoverer replenishment by supply ship concurrent with POS #1.
	4	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	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 12/18/08 App; Shell 2/23/09 Rev. App.; Shell 5/29/09 Supp. App; Shell 9/17/09 Comments).
POS ≡ Primary Operating Scenario

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

- SOS #7. Power to realign the 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. (Environ 6/26/09).

- 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 its 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 Discoverer. At this distance, the ice breaker vessel emissions are not considered to be emissions from an OCS source (See 40 C.F.R. § 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 Discoverer. At this distance, the emissions from the supply ship are not considered to be emissions from an OCS source (40 C.F.R. § 55.2).

To determine compliance quantitatively, the calculated significant emission rates associated with eight operating scenarios were modeled and the predicted concentration impacts of the air pollutants are compared to the NAAQS, PSD air quality increments, significant impact levels and/or ambient monitoring thresholds as shown in Table 5-1.

Importantly, only the POS #1 and its two alternatives have been re-modeled to reflect the significant emission reductions and other changes made to the proposed project since the August 2009 proposed permit (Shell 9/17/09 Comments). As discussed above SO_2 emissions have been reduced by 99%, PM_{10} and $PM_{2.5}$ emissions have been reduced by more than 70%, NO_x emissions have been reduced by 40%, VOC emissions have been reduced by 47%, and CO emissions have been reduced by 41%. POS #2 has not been remodeled since it has not changed, nor have SOS #1 through #6 been remodeled to reflect the emission reductions and changes to the project. Since the original modeling of POS #2 and SOS # 1 through #6 showed that NAAQS and increments would be met, and with the 40% reduction in NOx emissions and over 70% reduction in PM10 and PM2.5 emissions, EPA expects that remodeling these scenarios with the new lower emission rates would continue to confirm that NAAQS and increments would be met. Tables 5-15 and 5-16 show the original modeling results for POS #2 with the most recent background levels, and Appendix B shows the original modeling results for SOS #1 through #6, adjusted for the changes to the impact of POS #1, with the most recent background levels. These adjustments produce reasonable estimates of the predicted concentrations that re-modeling these scenarios would produce.

5.2.5 Modeling Methodology

To quantitatively evaluate the operating scenarios detailed in Section A, Shell employed the non-guideline ISC3-Prime model (EPA 8/26/04 ISC3-Prime). 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 (Air Sciences 7/7/09).

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 5/29/09 Supp. App.). Thus, the verification is sufficient.

In its review of Shell's previous modeling, EPA independently verified the maximum predicted model concentration impacts contained in the Shell supplemental revisions (Shell 5/29/09 Supp. App.) and emails (Environ 6/23/09-Emissions; Environ 6/23/090-Modeling). 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 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 effect on the predicted concentration impacts from Shell's exploration drilling program.

5.2.5.1 Urban/Rural Area Determination

The exploratory drilling operations will occur at 275 lease blocks contained in Lease Sale Area 193 (Air Sciences 3/20/09). 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/or in areas lacking any significant industrial and commercial activities or development, the two areas are considered rural for dispersion modeling purposes (Auer 1978).

5.2.5.2 Ambient Air Definition

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

5.2.5.3 Good Engineering Practice Stack Height

The Building Profile Input Program for PRIME (BPIPPRM) (EPA 4/21/09 User's Guide) is used to determine if an exhaust plume from each emission unit will be affected by a nearby structure. Specifically, the stack location and 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 BPIPPRM to make this determination for the 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 5/29/09 Supp. App.).

Similarly, the warehouse structure and heater stack information were input into BPIPPRM. It was determined that the warehouse structure would cause wake effects as well (Air Sciences

6/9/09). Therefore, Shell included building dimensions in the modeling of this combustion source (Shell 5/29/09 Supp. App.).

5.2.5.4 Meteorology

Because site-specific meteorology was not available, Shell used screening meteorology to predict the ambient air impact concentrations from its exploratory drilling program. The use of screening meteorology results in a more conservative approach to modeling because it assumes more persistent conditions conducive to high ambient pollution impacts than would be expected to actually occur.

Meteorological data from the SCREEN3 model is 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 (EPA 10/92 Screening Procedures). 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 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. 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 (Shell 5/29/09 Supp. App.).

5.2.5.5 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 5-2). The center of the 13 kilometer by 10 kilometer domain is the exploratory drill hole location below an anchored Discoverer. As shown in Figure 5-3, the drill hole location is at (93, 55) meters. Receptors in this domain are spaced every 100-meters for a total of 12576 points.

Exhibit 5
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Figure 5-2 – Modeling Domain and Receptor Points

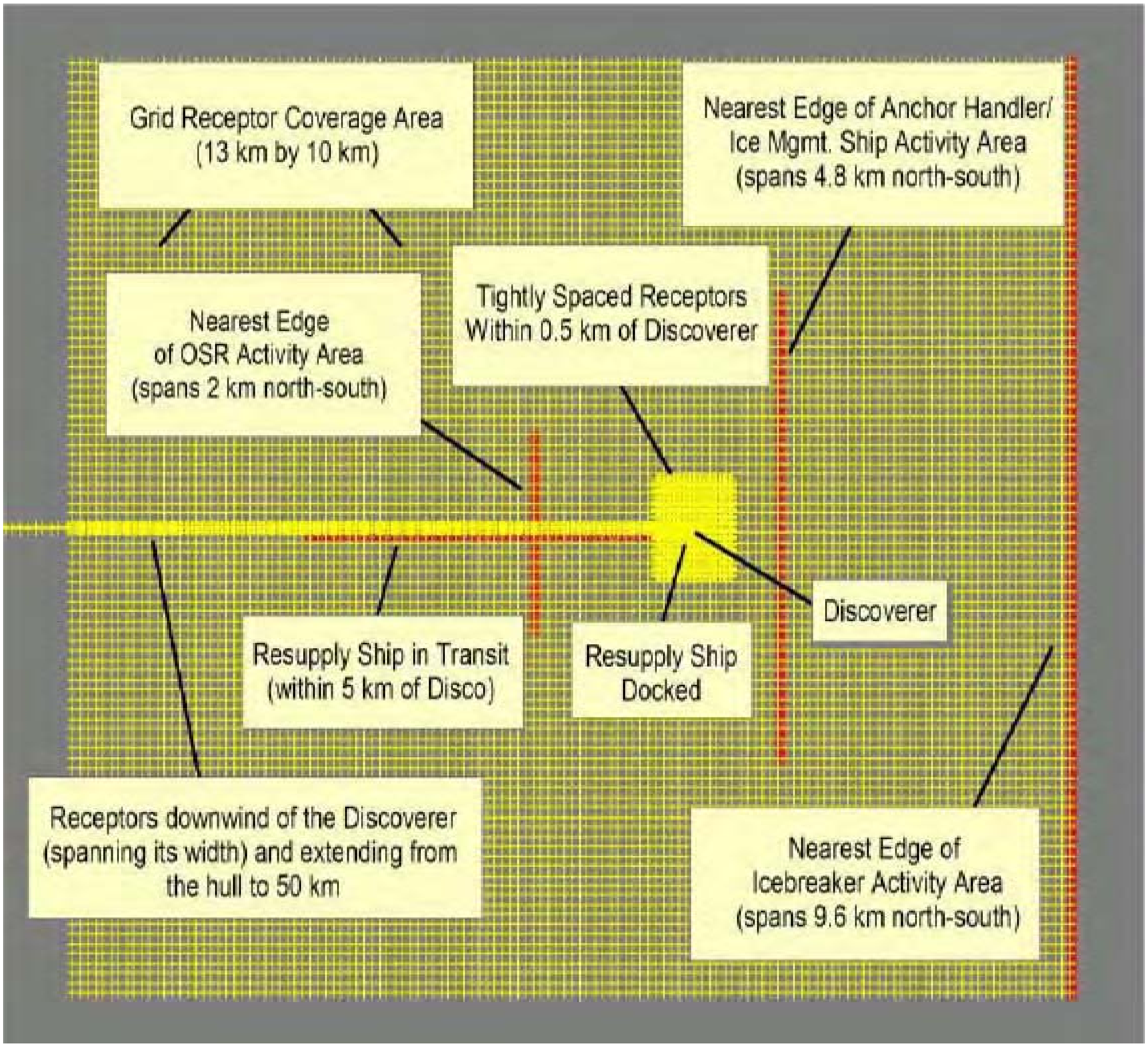

Exhibit 5
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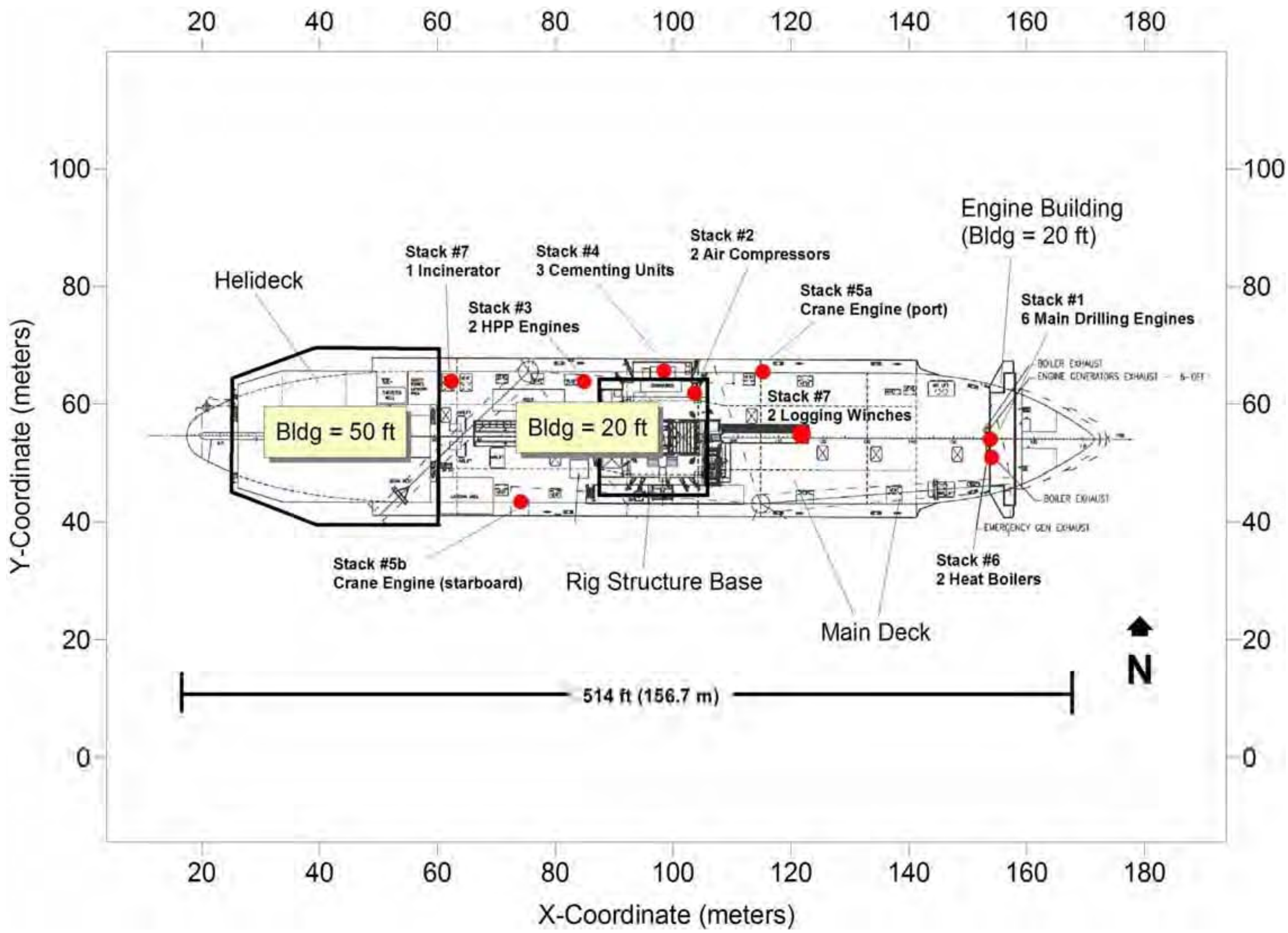
Figure 5-3 – Discoverer and Onboard Emission Units



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

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

- The second domain extends from the hull edge of the 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 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 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 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 2/23/09 Rev. App.).

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.

5.2.5.6 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 (EPA 9/95 ISC3), 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 Discoverer on board emission units as they operate in the Chukchi Sea (Shell 2/23/09 Supp. App.).

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5.2.5.7 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.

5.2.5.7.1 Emission Rates

Shell's exploratory drilling program 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 Appendix A. The vessels that are modeled as volume sources include the supply ship, the oil spill response vessel, the oil spill response work boats (3), Ice breaker #1, and Ice breaker #2. 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 rates for the vessels 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) 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 Discoverer and for anchor deployment and retrieval. 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, specifically, 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. As discussed above, these emission rates have been substantially reduced as compared to the emission rates in the August 2009 proposed permit.

5.2.5.7.2 Source Locations and Source Parameters

The location and source parameters of the emission units and sources appear in Table 5-6 and Table 5-7 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 5-3. In general, Ice Breaker #1 and Ice Breaker #2 will operate no closer than 4800-meters and 1000-meters upwind of the Discoverer respectively, during drilling operations. During the removal of ice that has accumulated on the bow of the Discoverer, Ice Breaker #2, can approach no closer than 100-meter from the drill ship. In general, the oil spill response fleet will operate downwind of the 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.

Table 5-6 – 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	0.00	0.00	7.62	478.00	6.60	0.46
				Height (m)	Sigma-y_o (m)	Sigma-z_o (m)	
Ice Breaker #1 [a,c,e]	Volume	[d]	[d]	25.22	46.51	9.21	
Ice Breaker #2 [a,c,f]	Volume	[e]	[e]	25.22	46.51	9.21	
Oil Spill ResponseK [a,c,g,h]	Volume	[f]	[f]	3.38	23.26	1.42	
Oil Spill ResponseN [a,c,h,i]	Volume	[g]	[g]	17.55	23.26	6.38	

Reference: Shell 5/29/09 Supp. App.; Shell 9/17/09 Comments

a. Origin of coordinate system (93, 55) meters or the drill hole location below the Discoverer.

b. 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.

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g. Oil Spill ResponseK is located about 2000-meters downwind of the drill hole location. There are three work boats.
h. Oil Spill 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.

Table 5-7 – 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 2/23/09 Rev. App.; Environ 7/15/09-PM10; Environ 7/15/09-PM2.5; Environ 7/16/09 Bow Washing1; Environ 7/16/09-Bow Washing2.
a. Occurs during Discoverer drilling operations or POS #1.
b. Supply ship Kilabuk is tied to the Discoverer.
c. The emergency generator emissions were modeled with FD 1-6 emissions.
d. Bow ice removal is performed by Ice Breaker #2and using six volume sources to represent the activity.
e. Minimum separation distance between Frontier Discover and Ice Breaker #2 is 100-meters during this bow ice removal.
f. The supply ship is modeled during the last 5-kilometers to the 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 setting and retrieval.

5.2.5.8 Scaling Factors

Scaling factors, as recommended by EPA, are used to calculate the concentrations for longer averaging periods from the hourly concentrations predicted by ISC3-Prime (EPA10//92

Screening Procedures). 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.

Table 5-8 – Scaling Factors

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

5.2.6 Background Monitoring Data and Preconstruction Monitoring

Background monitoring data is used in conjunction with modeled predictions to determine if emissions from the project would cause or contribute to violations of NAAQS. For background air monitoring data in its permit application, Shell 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 (see Figure 5-4 for the location of North Slope air monitoring stations). Shell is also relying on data from the Wainwright monitoring station to fulfill the preconstruction monitoring requirement of 40 C.F.R. § 52.21(m). As shown in Table 5-9, 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 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.

Table 5-9 – 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]		

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a. EPA has not promulgated a $PM_{2.5}$ monitoring threshold.

b. The net emissions increase NO_2 and VOC emissions exceed 100 tons per year. As a result, Shell is required to conduct an ozone analysis including data collection. See Section 3 and Appendix A for emission calculations.

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 community on the shores of the Chukchi Sea with a population of around 500. There are a number of air pollution sources in Wainwright, such as a diesel-fired utility electric power plant, a fuel storage facility, airport, residential heating, vehicle exhaust, and unpaved roads. Importantly, Wainwright experiences arctic weather conditions similar to those of the Chukchi Sea. While the Wainwright monitoring station will be somewhat influenced by local sources, EPA believes that it provides a conservative representation 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 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 ozone, with meteorological data being collected at the Wainwright airport. EPA approved the monitoring plan for the Wainwright monitoring station on January 5, 2009. EPA has reviewed the quarterly reports, including instrument operating parameters, and analyzed the measured air pollutant data during the collection period from November 8, 2008 to October 31, 2009 for consistency with 40 C.F.R. § 52.21 and the approved monitoring plan. (AECOM 2008 QAPP; AECOM 11/08-1/09; AECOM 2/09-4/09; AECOM 5/09; AECOM 6/09;AECOM 8/09-10/09; EPA 7/31/09 Wainwright QA Memo; EPA 1/7/10 Wainwright QA Memo EPA; 1/7/10 Deadhorse QA Memo). EPA has concluded that the SO_2, NO_2, NO_x, NO, CO, ozone and PM_{10} data collected from November 8, 2008 to October 31, 2009 and the PM2.5 data collected from March 6, 2009 to October 31, 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. (EPA 7/31/09 QA/QC Memo).

Exhibit 5
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Figure 5-4 – North Slope Monitoring Stations

Based on information provided by Shell and other available information, EPA believes that the monitoring data collected at the Wainwright monitoring site is, in general, conservatively representative of air quality in the Chukchi Sea where Shell will be conducting its exploratory drilling program and that a complete and adequate air quality analysis as required by 40 C.F.R. § 51.21(m)(1)(iv) can be accomplished with 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. Measurements of the two particulate matter air pollutants ($PM_{2.5}$ and PM_{10}) also follow expectations, with higher levels during the summer and fall when the ground is not frozen or covered with snow.

There are nearby sources of fugitive dust, including unpaved roads and other unpaved areas such as airport runways, that would be expected to contribute to particulate matter concentrations at the Wainwright monitoring site. Shell has submitted an analysis of the particulate matter data to show that levels on days with high winds and dry soils are much higher than other days. (Shell 12/9/09; Environ 12/18/09-PM). For example, the average and 24-hour maximum $PM_{2.5}$ concentrations were more than twice as high on days with high winds and no precipitation than on other days. Shell contends that this analysis, along with the fact that there are sources of dust in the vicinity of the Wainwright monitor, establishes that the highest recorded particulate matter levels at the Wainwright are associated with local windblown dust and are not reflective of conditions on the OCS source where Shell is conducting drilling operations more than 50 miles from shore. Based on the information provided by Shell, EPA agrees that the $PM_{2.5}$ and PM_{10} values recorded at the Wainwright monitoring station on high wind days with no precipitation are not representative of air quality in the vicinity of the Shell's exploratory drilling operations in the Chukchi Sea and are appropriately excluded from consideration in determining the background levels on the OCS near the drilling sites. Accordingly, EPA has determined an average and a maximum concentration for both $PM_{2.5}$ and PM_{10} that are used as background concentrations for both onshore and offshore impact analyses. The offshore background concentrations exclude the high wind/non-precipitation days, while the onshore background concentrations include all days. Table 5-10 summarizes the analysis of $PM_{2.5}$ and PM_{10} data and the final background levels that are used for the offshore (in the vicinity of Shell's operations) and onshore NAAQS demonstrations (the nearest on-shore locations to Shell's operations).

Table 5-10 Determination of Background PM_{10} and $PM_{2.5}$ Concentrations for Use with Offshore and Onshore Impact Analyses

	24-hour PM2.5 Concentration (ug/m3)			**24-hour PM10 Concentration (ug/m3)**		
	# Days	**Average**	**Maximum**	**# Days**	**Average**	**Maximum**
Precipitation Days [a]						
Non-High Wind Days [b]	52	2.8	7.0	54	13.4	54.0
High Wind Days [c]	6	3.8	7.0	4	13.8	28.0
Non-Precipitation Days [d]						
Non-High Wind Days [b]	133	2.7	11.0	126	15.7	91.0
High Wind Days [c]	36	6.1	23.0	35	20.3	114.0
Offshore Background Concentrations (Excluding Non-Precipitation Days/High Wind Days)						
Offshore Background	191	**2.8**	**11.0**	184	**15.0**	**91.0**
Onshore Background Concentrations (All Days)						
Onshore Background	227	**3.3**	**23.0**	219	**15.8**	**114.0**

Reference: Shell 12/9/09; Environ 12/18/09-PM
a. These days fall within a two day period (on that day or on the previous day) where there is total precipitation greater than 0.01 inches.
b. Days with less than 4 hours of winds greater than 10 meters/second.
c. Days with at least 4 hours of winds greater than 10 meters/second.
d. These days fall within a two day period (on that day or on the previous day) where there is total precipitation equal to or less than 0.01 inches.

EPA expects that the background levels of pollution, and especially $PM_{2.5}$ and PM_{10}, more than 50 miles offshore in the vicinity of Shell's planned exploratory drilling operations are likely to be lower than the levels recorded at Wainwright. Table 5-11 summarizes the background concentrations that are used in the analysis of NAAQS compliance for both the offshore areas near the Discoverer and in the onshore communities of Wainwright and Point Lay.

Table 5-11 Background Ambient Concentrations for Use with Offshore and Onshore Impact Analyses

Pollutant	Averaging Period	Onshore Background	Offshore Background
NO_2	Annual [b]	2.0	2.0
$PM_{2.5}$ [c]	24-Hour [a]	23	11
	Annual [b]	3.3	2.8
PM_{10}	24-Hour [a]	114	91
	Annual [b]	15.8	15.0
SO_2	3-Hour [a]	17	17
	24-Hour [a]	10	10
	Annual [b]	0.5	0.5
CO	1-Hour [a]	1050	1050
	8-Hour [a]	941	941
Ozone	1-Hour [a]	114	114
	8-Hour [a]	93	93

Reference: AECOM 11/08-1/09; AECOM 2/09-4/09; AECOM 5/09; AECOM 6/09; AECOM 8/09-10/09); Reference: Shell 12/9/09; Environ 12/18/09-PM.

a. The period of record for the data collection at Wainwright is November 8, 2008 to October 31, 2009. Except for the Offshore Background values for PM_{10} and $PM_{2.5}$, the maximum short-term concentrations (24 hours and less) are given here.

b. Except for the Offshore Background values for PM_{10} and $PM_{2.5}$, the value is an average over the entire dataset.

c. The period of record for $PM_{2.5}$ data collection at Wainwright is March 6, 2009 to October 31, 2009.

5.2.7 Ozone

Because NO_x and VOC net emissions exceed 100 tons per year, Shell is required under the PSD regulation to perform an ozone ambient air quality impact analysis including gathering ambient air measurements. Ozone is inherently a regional pollutant, the result of chemical reactions between emissions from many sources over a period of hours or days, and over a large area. Ozone is formed in the atmosphere through a chemical reaction that includes NO_x, VOC and CO in the presence of sunlight. The sources of these air pollutants are mainly combustion sources such as power plants, refineries and automobiles.

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

The land area closest to Shell's exploration operations in the Chukchi Sea is part of the State of Alaska's Northern Interstate Air Quality Control Region. See 40 C.F.R. § 81.246. This region is designated as either attainment or unclassifiable for all criteria pollutants, including ozone. See 40 C.F.R. § 81.301. Actual emissions of ozone precursors from point and area sources in the North Slope Borough were approximately 42,500 tons per year of NOx and 1,600 tons per year of VOC, with the vast majority (41,000 and 1,100 tons per year, respectively) from point sources in the North Slope oil and gas fields near Deadhorse. In contrast, potential emissions from Shell's exploration operations are expected to be approximately 1181 tons per year of NO_x and 108 tons per year of VOC, and there are no other stationary source operations near Shell's exploration operations in the Chukchi Sea. The contribution from these precursor emissions to the formation of ozone is expected to be small downwind of Lease Sale Area 193.

Over the past ten years, there have been monitoring programs that measured ozone and ozone precursors (i.e., NO_x and VOC) in the North Slope where oil and gas operations are currently located. The ozone measurement programs include Barrow (2003 - 2005), BPX-Badami (1999), BPX-Prudhoe Bay (2006 - 2007), CPAI-Alpine (Nov 2004 - Dec 2005) and CPAI-Kuparuk River (Jun 2001 - June 2002). Measurements from these six sites indicate that the highest 1-hour concentration was 73 parts per billion 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. (Shell 11/23/09 Supp. App.).

As discussed above, 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 5-11 shows the maximum hourly and 8-hour ozone concentrations measured during the first twelve months of data collection at Wainwright. The 1-hour and 8-hour measured concentrations represent 49 percent and 63 percent of their NAAQS, respectively.

Given the low level of ozone precursor emissions from Shell's exploration operations in comparison to regional emissions of ozone precursors, the fact that there are no other stationary sources in the more immediate regional vicinity of Shell's operations in the Chukchi Sea that contribute ozone precursors to the airshed, and the moderate levels of the maximum 1-hour and 8-hour measured on the North Slope and at Wainwright, the contribution of the ozone precursor

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emissions from Shell's exploration operations to the formation of ozone in the region is expected to be small. For these reasons, EPA believes that emissions from Shell's exploration operations will not cause or contribute to a violation of the NAAQS for ozone.

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. Table 5-12 summarizes the highest predicted and total impacts for the POS #1 and its alternatives. The levels range from a low of 3.1% of the annual SO_2 NAAQS to a high of 84.0% of the 24-hour $PM_{2.5}$ NAAQS. In addition, Table 5-13 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 10% of their respective NAAQS and the total predicted impacts for PM_{10} and $PM_{2.5}$ are less than 78% 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.

Table 5-12 – Maximum Predicted Impacts on NAAQS and PSD Class II Increments from POS #1 and Alternatives

Pollutant	Averaging Period	Concentration (ug/m^3)			PSD Class II Increment (ug/m^3)	Percent Increment	NAAQS (ug/m^3)	Percent NAAQS
		Total No Background	Back ground	Total th Background				
NO_2 [2]	Annual	18.2	2.0	20.2	25	72.8%	100	20.2%
$PM_{2.5}$	24-Hour	18.4	11	29.4	*	---	35	84.0%
	Annual	1.3	2.8	4.1	*	---	15	27.3%
PM_{10}	24-Hour	19.4	91	110.4	30	64.7%	150	73.6%
	Annual	1.4	15.0	16.4	17	8.2%	---	---
SO_2	3-Hour	68.8	17	85.8	512	13.4%	1,300	6.6%
	24-Hour	26.8	10	36.8	91	29.5%	365	10.1%
	Annual	2.0	0.5	2.5	20	10%	80	3.1%
CO	1-Hour	396.6	1050	1446.6	*	---	40,000	3.6%
	8-Hour	356.9	941	1297.9	*	---	10,000	13.0%

Reference: Shell 9/17/09 Supp. App.; Environ 12/2/09)
*EPA has not promulgated increments for $PM_{2.5}$ or CO

Table 5-13 – Predicted Impacts on NAAQS from POS #1 and Alternatives at Wainwright and Point Lay

Pollutant	Averaging Period	Concentration (ug/m^3) Max. Modeled [1] Wainwright	Point Lay	Background	Wainwright Total with Background	Point Lay Total with Background	NAAQS	Percent NAAQS Wainwright	Percent NAAQ Point Lay
NO_2	Annual	1.7	1.8	2.0	3.7	3.8	100	3.7%	3.8%
$PM_{2.5}$	24-Hour	2.6	2.7	23	25.6	25.7	35	73.1%	73.4%
	Annual	0.2	0.2	3.3	3.5	3.5	15	23.3%	23.3%
PM_{10}	24-Hour	2.8	3.0	114	116.8	117.0	150	77.9%	78.0%
	Annual	0.2	0.2	15.8	16.0	16.0	---	---	---
SO_2	3-Hour	7.3	7.8	17	24.3	24.8	1,300	1.9%	1.9%
	24-Hour	4.1	4.4	10	14.1	14.4	365	3.9%	3.9%
	Annual	0.3	0.3	0.5	0.8	0.8	80	1.0%	1.0%
CO	1-Hour	34.1	36.4	1050	1084.1	1086.4	40,000	2.7%	2.7%
	8-Hour	30.6	32.7	941	971.6	973.7	10,000	9.7%	9.7%

Reference: Shell 9/17/09 Supp. App.
[1] The nearest villages to Shell's Chukchi leases are Wainwright (~110 km away) and Point Lay (~100 km away)

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 5-12 above also shows the predicted maximum concentrations for POS #1 and its alternatives as compared to the PSD increments for Class II areas.

As also shown in Table 5-14 below, predicted impacts for the Class II increments in Point Lay and Wainwright are significantly lower, less than 5% for all SO_2, increments and the 24-hour PM_{10} increment and less than 10% for the annual NO_x increment and the 24-hour PM_{10} increment.

Table 5-14 – Predicted Impacts on PSD Class II Increments from POS #1 and Alternatives at Wainwright and Point Lay

Pollutant	Averaging Period	Concentration (g/m^3)				
		Max. Modeled [1]		Class II Increment	Wainwright Percent Increment	Point Lay Percent Increment
		Wainwright	Point Lay			
NO_2	Annual	1.7	1.8	25	6.8%	7.2%
PM_{10}	24-Hour	2.8	3.0	30	9.3%	10.0%
	Annual	0.2	0.2	17	1.2%	1.2%
SO_2	3-Hour	7.3	7.8	512	1.4%	1.5%
	24-Hour	4.1	4.4	91	4.5%	4.8%
	Annual	0.3	0.3	20	1.5%	1.5%

Reference: Shell 9/17/09 Supp. App

[1] The nearest villages to Shell's Chukchi leases are Wainwright (~110 km away) and Point Lay (~100 km away)

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 8/5/09).

5.2.10 Conclusions

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 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 Discoverer, ice breaker fleet, oil spill response fleet and/or supply vessel.

Based on the conservative modeling assumptions and the predicted SO_2, NO_2, CO, PM_{10}, and $PM_{2.5}$ concentration impacts for the primary and secondary operating scenarios, EPA has concluded that Shell’s exploratory drilling project is expected to comply with the applicable NAAQS and Class II area air quality increments.

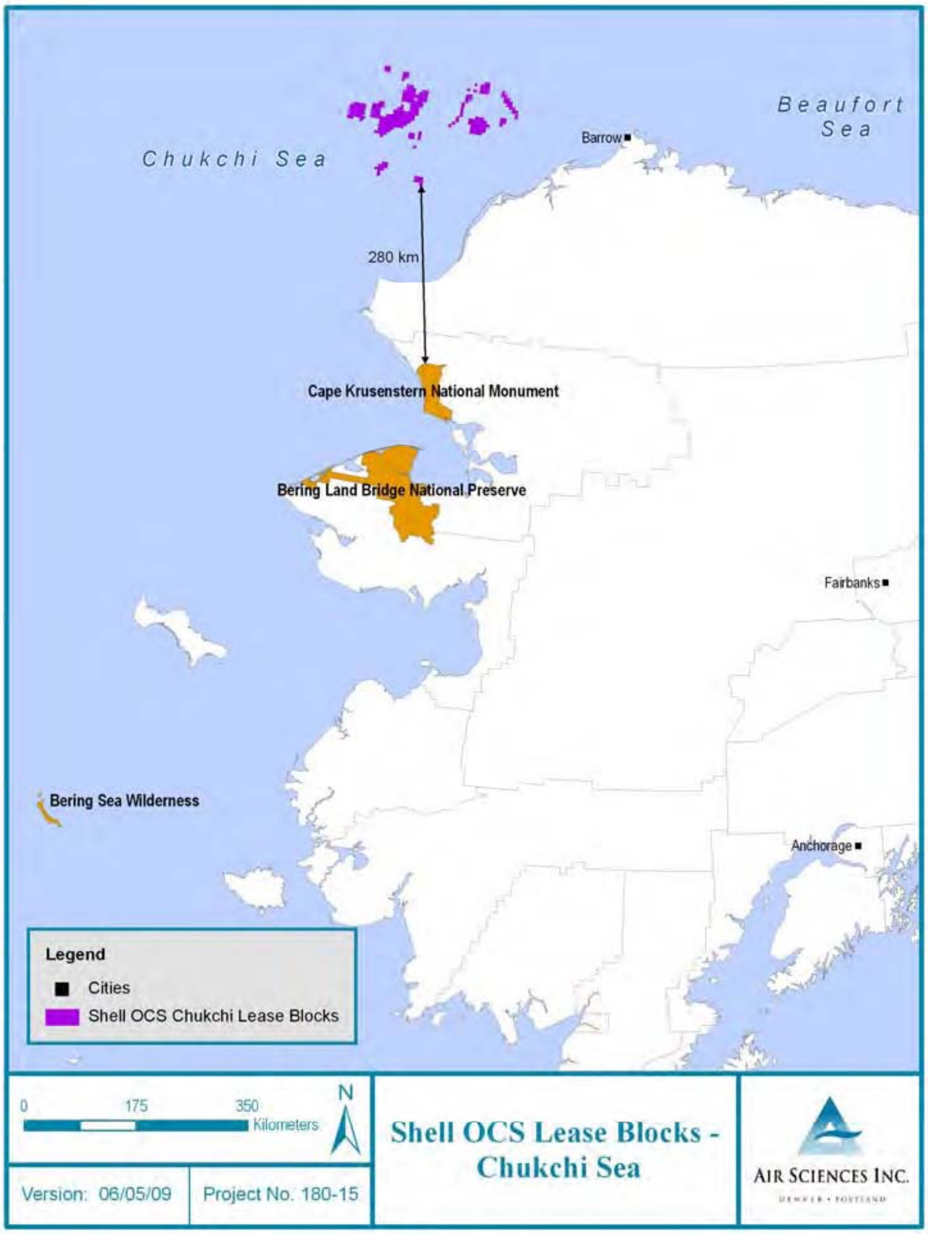
5.3 Additional Impacts Analysis

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

5.3.1 Class II Area Visibility

The National Park Service identified two of Class II national monuments as areas of concern (Notar 6/3/09): Cape Krusenstern National Monument and Bering Land Bridge National Monument (see Figure 5-5). 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 8/5/09).

Figure 5-5 – Location Map of Class II Area National Monuments



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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 (Air Sciences 6/1/09). EPA estimates the water vapor emissions to be 67 ton per day from the Discoverer and 395 tons per day from all combustion sources. Water vapor emissions from the Discoverer and the Associated Fleet may contribute to fog formation depending on atmospheric conditions.

Visible exhaust plumes are expected from the Discoverer and Associated Fleets activities during exploratory drilling activities. 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 in the significant impact area of the proposed new source that is expected to occur as a result of its permitted activities and general commercial, residential, industrial, and other growth associated with the project. Analysis for vegetation having no significant commercial or recreational value is not required. All areas within the largest possible significant impact area radius of 50-kilometers centered on the Discoverer are ocean. Shell analyzed the potential impacts from the project on aquatic vegetation having commercial or recreational value and sediment by reviewing published literature and consulting with numerous government agencies, local groups and residents, and the University of Alaska (Air Sciences 6/1/09). 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 Discoverer. In addition, Shell contemplates building a warehouse, heated by either natural gas or heating oil, at either Wainwright or Barrow. As shown in Table 5-15 and Table 5-16 below, 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.

Table 5-15 – Primary Operating Scenario #2 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Predicted (μg/m^3)	Existing (μg/m^3)	Total [c] (μg/m^3)	NAAQS (μg/m^3)	Percent NAAQS
Sulfur Dioxide (SO_2)	3-Hour	56.20	17	73.2	1300	5.63
	24-Hour	37.50	10	47.5	365	13.01
	Annual	3.10	0.5	3.6	80	4.50
Nitrogen Dioxide (NO_2)	Annual	3.70	2.0	5.70	100	5.70
Carbon Monoxide (CO)	1-Hour	24.60	1050	1074.60	10000	10.75
	8-Hour	22.10	941	963.1	40000	2.41
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	9.80	114	123.8	150	82.53
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	9.80	23.0	32.8	35	93.71
	Annual	0.81	3.3	4.11	15	27.40

Reference: Air Sciences 6/9/09.
a. The sum of the "predicted" impact and "existing" background.

Table 5-16 – Primary Operating Scenario #2 Predicted Concentration Impact Comparison with Class II Area Air Quality Increments

Air Pollutant	Averaging Period	Predicted (μg/m^3)	Increment (μg/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: Air Sciences 6/9/09.
a. EPA has not promulgated $PM_{2.5}$ 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 C.F.R. § 52.21(p), the Federal Land Managers are responsible for the management of mandatory federal Class I areas, including the protection of air quality related values. The air quality related values include sulfate and nitrate deposition and visibility impairment. The nearest Class I 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 8/5/09).

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6. OTHER REQUIREMENTS

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

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

Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires federal agencies to consult with 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. Therefore, MMS has served as the Lead Agency for ESA Section 7 and MSA 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 (ITR) 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, EPA reviewed the ESA and MSA consultation documents prepared by MMS and the following biological opinions (BOs) issued by the Services upon conclusion of their inter-agency ESA consultations regarding impacts from exploratory drilling on threatened and endangered (T&E) species and designated critical habitats for listed species:

- U.S. FWS March 27, 2007, Biological Opinion for Chukchi Sea Planning Area Oil and Gas Lease Sale 193 and Associated Seismic Surveys and Exploratory Drilling.
- Programmatic Biological Opinion for Polar Bears on Chukchi Sea Incidental Take Regulations, Fairbanks Fish and Wildlife Field Office, June 3, 2008
- National Marine Fisheries Service's (NMFS) revised Biological Opinion for Federal oil and gas leasing and exploration by the Minerals Management Service (MMS) within the Alaskan Beaufort and Chukchi Seas, July 17, 2008

Since the prior consultations and BO's address the same types of exploratory drilling activities authorized by the air permit that EPA is issuing to Shell, EPA relied in part on those conclusions for our final determination. EPA also gathered additional information regarding potential

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impacts of emissions of air pollutants on the T&E species in the Chukchi Sea Lease Sale 193 Area. Based upon the best available data, EPA determined that the issuance of this Clean Air Act permit to Shell for exploratory drilling is not likely to cause any adverse effects on listed species and essential fish habitats beyond those already identified, considered and addressed in the prior consultations. EPA forwarded our determination to FWS and NOAA on September 4, 2009, and additional follow-up information was provided to NOAA on September 24, 2009. The FWS and NOAA concurred in writing with our determination on September 23, 2009 and October 26, 2009, respectively.

This proposed CAA permit includes a condition requiring Shell to comply with all other federal regulations. This condition requires Shell to obtain an annual Letter of Authorization (LOA) from the FWS in accordance with the ITR assuring further assessment of impacts to marine mammals based on any new scientific data. Section 101 (a)(5) of the Marine Mammal Protection Act (MMPA) directs the Secretary of Commerce to allow, upon request by U.S. citizens engaged in a specific activity (other than commercial fishing) in a specified geographical region, the incidental but not intentional taking of small numbers of marine mammals if certain findings are made. Such authorization may be accomplished through issuance of an incidental harassment authorization (IHA).

6.2 National Historic Preservation Act

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to take into account the effects of their undertakings on historic properties. Section 106 requires the lead agency official to ensure that any federally funded, permitted, or licensed undertaking will have no effect on historic properties that are on or may be eligible for the National Register of Historic Places. The Section 106 process seeks to accommodate historic preservation concerns with the needs of federal undertakings through consultation among the agency official and other parties with an interest in the effects of the undertaking on historic properties, commencing at the early stages of project planning. The goal of consultation is to identify historic properties potentially affected by the undertaking, assess the potential effects of the undertaking on historic properties, and seek ways to avoid, minimize, or mitigate any adverse effects on historic properties. If more than one federal agency is involved in an undertaking, some or all the agencies may designate a lead federal agency for this analysis. Section 106 requires the lead agency to consult with the State Historic Preservation Office (SHPO) on actions that may affect historical sites. As the lead action agency, MMS has consulted and will continue to consult with the SHPO on Shell's oil exploration activities in federal waters. In a letter dated November 13, 2009, MMS sought the SHPO's concurrence in MMS's determination that Shell's exploratory drilling in Lease Area 193 under Shell's Exploration Plan will have no effect on historic properties. The SHPO concurred in MMS's determination on November 17, 2009. In fulfilling its NHPA obligations for this permitting action, EPA intends to rely on these MMS consultations. EPA will conduct additional compliance activities necessary to address any EPA-permitted activities not covered in MMS' consultations.

6.3 Coastal Zone Management

The Alaska Coastal Management Program (ACMP), authorized by the State of Alaska's 1977 Alaska Coastal Management Act, is designed to protect Alaska's rich and diverse coastal

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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.

6.4 Executive Order 12898 – Environmental Justice

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

Consistent with EO 12898 and EPA's environmental justice policy (OEJ 7/24/09), in making decisions regarding permits, such as OCS and PSD permits, EPA gives appropriate consideration to environmental justice issues on a case-by-case basis, focusing on whether its action would have disproportionately high and adverse human health or environmental effects on minority or low-income populations. EPA's proposed OCS/PSD air permitting action on the 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. EPA's review of demographic characteristics showed that many of the potentially impacted communities have a significantly high percentage of Alaskan Natives, who are considered a minority under EO 12898, and people who speak a language other than English at home (EJ GAT 7/28/09).

EPA has taken several measures to provide meaningful involvement for the environmental justice communities potentially impacted by this permit. EPA has recently developed the "Region 10 North Slope Communications Protocol" to support the meaningful involvement of the North Slope communities in EPA decision-making (NSCP 5/09). The development of the public participation process for this permit was guided by the NSCP and will inform the

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communities of the North Slope about the OCS permitting program and this proposed OCS/PSD permit. In an effort to engage the potentially affected communities early in the process, managers of EPA Region 10's air and water programs conducted early outreach on air and water permitting in May 2009 in Kotzebue and Barrow (EPA 7/27/09 Outreach Memo). EPA has held meetings and conference calls to specifically solicit input on environmental justice concerns related to this permitting action, as well as other potential OCS air permitting actions on the Chukchi and Beaufort Seas (ICAS 7/23/09; NSB 6/26/09 Transcript). EPA held public hearings and community meetings on the initial August 2009 proposal and has also scheduled a public hearing on this new modified permit.

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

6.5 Executive Order 13175 – Tribal Consultation

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

Prior to beginning the public comment period on the August 2009 proposed permit, EPA sent letters to 11 potentially interested tribal governments, offering government-to-government consultation opportunities on EPA's proposed action to issue Shell OCS/PSD permits for exploration drilling on the Chukchi and Beaufort Seas. The letters were sent on June 26, 2009 to Native Village of Point Hope, Native Village of Point Lay, Wainwright Traditional Council, Native Village of Anuktuvuk Pass, Native Village of Atqasuk, Native Village of Barrow, Inupiat Community of the Arctic Slope, Native Village of Kaktovik, 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 also attempted to contact each of these tribal governments to ensure the letters were received.

EPA received a request for tribal consultation from the Inupiat Community of the Arctic Slope (ICAS) and held a government-to-government consultation meeting with ICAS in Barrow on September 23, 2009. Concerns expressed included drilling during November and December due to severe winter conditions; a desire for more information regarding the air quality model; the

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reliability of self-monitoring data and a preference for monitoring data collected by an independent third party; and a request that monitoring information and data be reported to the communities.

ICAS also requested that EPA consult with all tribal governments on the North Slope and that this occur in person in the local communities. Although EPA did not receive requests for consultation from other tribal governments prior to the public hearings, EPA held informational meetings for the local communities of Point Hope, Barrow, and Wainwright during the week of September 21, 2009. The informational meeting in Point Hope on September 24, 2009, did end up including an unscheduled government-to-government consultation meeting with the Native Village of Point Hope. Concerns expressed at the consultation with the Native Village of Point Hope included the adequacy of the baseline air quality data for the Chukchi and Beaufort Seas; a desire for community involvement in the collection of baseline data collection and compliance monitoring; and the potential impact on respiratory health. The Native Village of Point Hope requested another opportunity for government-to-government consultation with EPA to discuss their concerns prior to the finalization of the Shell OCS/PSD permit.

The concerns expressed by the tribal governments and other public comments were a factor in EPA's decision to propose the new modified permit and initiate a second opportunity for public comment. The new modified permit contains measures that further substantially reduce the air emissions and associated impacts from Shell's exploration drilling program in the Chukchi Sea.

EPA is offering ICAS and the Native Village of Point Hope, the tribal governments that requested consultation on the August 2009 initial proposed permit, the opportunity to consult on this new modified proposed permit. Whenever possible, EPA will accommodate requests for consultation received any time during the permitting process.

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

6.6 National Environmental Policy Act

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

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

Exhibit 5
AEWC & ICAS

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APPENDIX A (Revised January 5, 2010)

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

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

Associated Fleets

	Potential to Emit (tons/year)						
Description	**CO**	**NO_x**	**$PM_{2.5}$**	**PM_{10}**	**SO_2**	**VOC**	**Lead**
Ice Management Fleet - Generic							
Ice Breaker # 1	160.50	849.88	33.60	38.43	0.65	35.87	3.74E-02
Ice Breaker #2	237.17	71.19	11.15	11.79	0.68	27.69	3.73E-02
Resupply Ship - Generic	0.56	4.24	0.26	0.32	1.13E-03	0.10	2.06E-05
OSR Fleet - Generic							
Nanuq - Main Ship	39.14	172.35	1.86	2.51	0.39	13.59	2.81E-02
Oil Spill Response, Kvichak No. 1, 2 and 3 Work Boats	1.72	39.39	0.78	0.78	0.04	0.80	7.51E-04
Sub-Total Emissions from Fleets	439.08	1,137.04	47.64	53.82	1.76	78.05	0.10
TOTAL PROJECT EMISSIONS	449.08	1188.27	51.58	57.78	1.99	87.28	0.11

Notes

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

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

Emissions Factor References

CO	From Caterpillar, See permit application dated 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
6 Control efficiency is based on use of oxidation catalyst. NOx emission factor already reflects controlled emission rate.

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.

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

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34-36, max of Cat engine tests
$PM_{2.5}$	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 2/23/2009, Appendix B, page 1
2 Engine rating per permit application dated 2/23/2009, 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 120 minutes of operation per day and 48 hours per year per Shell request dated 9/17/2009

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.

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

Emissions Factor References

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

Conversions Used

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

Footnotes/Assumptions

1 Engine specification per permit application dated 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
6 Control efficiency is based on use of oxidation catalyst. CO emission factor already reflects controlled emission rate.

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

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[6,7] Daily (gal)	Annual[8] (gal)	Control Efficiency[4,5]	Potential to Emit Hourly, lb/hr	Daily[7], lb/day	Annual[7], tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
Base Case Scenario											
CO	2.99	g/hp-hr	0	44,338	0.9	0	0	0.25	0	0	0.007
NO_x	9.81	g/hp-hr	0	44338		0	0	8.18	0	0	0.235
$PM_{2.5}$	1.26	g/hp-hr	0	44338	0.85	0	0	0.16	0	0	0.005
PM_{10}	1.26	g/hp-hr	0	44338	0.85	0	0	0.16	0	0	0.005
SO_2	0.000030	lb/lb fuel	0	44338		0	0	4.71E-03	0	0	1.354E-04
VOC	1.48	g/hp-hr	0	44338	0.9	0	0	0.12	0	0	3.452E-03
Lead	0.000029	lb/MMBtu	0	44338		0	0	8.56E-05	0	0	2.462E-06
Alternative Scenario #1											
CO	2.99	g/hp-hr	352	44,338	0.9	0.16	3.96	0.25	0.02	0.021	0.007
NO_x	9.81	g/hp-hr	352	44,338		5.41	129.76	8.18	0.682	0.681	0.235
$PM_{2.5}$	1.26	g/hp-hr	352	44,338	0.85	0.10	2.50	0.16	0.013	0.013	0.005
PM_{10}	1.26	g/hp-hr	352	44,338	0.85	0.10	2.50	0.16	0.013	0.013	0.005
SO_2	0.000030	lb/lb fuel	352	44,338		3.11E-03	7.47E-02	4.71E-03	3.92E-04	3.92E-04	1.35E-04
VOC	1.48	g/hp-hr	352	44,338	0.9	0.08	1.96	0.12	1.01E-02	1.03E-02	3.45E-03
Lead	0.000029	lb/MMBtu	352	44,338		5.66E-05	1.36E-03	8.56E-05	7.13E-06	7.13E-06	2.46E-06
Alternative Scenario #2											
CO	2.99	g/hp-hr	704	44,338	0.9	0.16	7.91	0.25	0.02	0.042	0.007
NO_x	9.81	g/hp-hr	704	44,338		5.41	259.53	8.18	0.682	1.363	0.235
$PM_{2.5}$	1.26	g/hp-hr	704	44,338	0.85	0.10	5.00	0.16	0.013	0.026	0.005
PM_{10}	1.26	g/hp-hr	704	44,338	0.85	0.10	5.00	0.16	0.013	0.026	0.005
SO_2	0.000030	lb/lb fuel	704	44,338		3.11E-03	0.15	4.71E-03	3.92E-04	7.87E-04	1.35E-04
VOC	1.48	g/hp-hr	704	44,338	0.9	0.08	3.92	0.12	1.01E-02	2.06E-02	3.45E-03
Lead	0.000029	lb/MMBtu	704	44,338		5.66E-05	2.72E-03	8.56E-05	7.13E-06	1.43E-05	2.46E-06

Emissions Factor References

CO	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 2 tests
NO_x	From Health Assessment Document for Diesel Engine Exhaust, EPA/600/8-90/057F, May 2002, pages 2-34 and 2-35, max of 4 tests
$PM_{2.5}$	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 CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 Daily maximum operation and operating scenarios are based on Shell's submittal dated 9/17/2009
7 Daily and annual maximum fuel usage is for both engines, in aggregate: 44,338 gallons
8 Annual maximum fuel usage limit is for all operating scenarios in aggregate.

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 CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 Maximum operation per season is based on an owner requested limit of: 63661 gallons
Per 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] Daily	Annual	Control Efficiency[4, 5]	Potential to Emit[6] Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec 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 (websit
April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 See page 11 for daily and annual emissions

Shell Offshore Inc.
OCS/PSD Permit for
Frontier Discoverer 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 CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
6 The 71 series engines were a product of the Detroit Diesel Engine Division of General Motors
This engine is a 3-cylinder version of this family of engine - see 4/9/2009 e-mail from Air Sciences (Sabrina Pryor) to EPA (Pat Nair)
For this emission inventory, emission factors used are the highest for a 71 series engine
7 See page 11 for daily and annual emissions

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

Emissions Unit:	FD-19	Logging Winch
Make/Model[1]:	Caterpillar C7	
Fuel:	Liquid distillate, #1 or #2	
Rating[2]:	250	hp
Maximum Hourly Fuel Use[3]:	93	lbs/hour
Control Equipment:	None	

Emissions are on a per-engine basis.

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[4]		Control Efficiency[5]	Potential to Emit[4]			Potential to Emit in g/sec
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour
CO	3.5	g/kW-h			0.8	0.29			0.037
NO_x	4.0	g/kW-h				1.64			0.207
$PM_{2.5}$	0.2	g/kW-h			0.85	0.01			0.001
PM_{10}	0.2	g/kW-h			0.85	0.01			0.001
SO_2	0.000030	lb/lb fuel				2.79E-03			3.52E-04
VOC	4.0	g/kW-h				1.64			2.07E-01
Lead	0.000029	lb/MMBtu				5.08E-05			6.39E-06

Emissions Factor References

CO	From Tier 3 emission limit in 40 CFR 89.112
NO_x	From Tier 3 emission limit in 40 CFR 89.112 (Limit is for NOx and NMHC, in aggregate)
$PM_{2.5}$	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 (Limit is for NOx and NMHC, in aggregate)
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

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

Footnotes/Assumptions

1 Engine specification per 12/10/2009 e-mail and attachment from Air Sciences (Rodger Steen) to EPA (Pat Nair).
2 Engine rating per 12/10/2009 e-mail and attachment from Air Sciences (Rodger Steen) to EPA (Pat Nair).
3 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
4 See page 11 for daily and annual emissions
5 Control efficiency is based on use of CDPF

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 PE4020TF270D		
Fuel:	Liquid distillate, #1 or #2		
Rating[2]:	35	hp	converted from
Maximum Hourly Fuel Use[3]:	13.0	lbs/hour	
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC		

Emissions are on a per-engine basis.

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[7]		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	0.03			0.004
NO_x	7.5	g/kW-hr				0.43			0.054
$PM_{2.5}$	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				3.91E-04			4.92E-05
VOC	7.5	g/kW-hr			0.9	0.04			5.04E-03
Lead	0.000029	lb/MMBtu				7.11E-06			8.95E-07

Emissions Factor References

CO	From Tier 2 emission limit in 40 CFR 89.112		
NO_x	From Tier 2 emission limit in 40 CFR 89.112		
$PM_{2.5}$	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 12/10/2009 e-mail and attachment from Air Sciences (Rodger Steen) to EPA (Pat Nair).
2 Engine rating per 12/10/2009 e-mail and attachment from Air Sciences (Rodger Steen) to EPA (Pat Nair).
3 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
4 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 CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
5 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)
7 See page 11 for daily and annual emissions

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 details
Control Equipment:	Clean Air Systems PERMIT™ Filter for control of CO, $PM_{2.5}$, PM_{10} and VOC on all engines except FD-19

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

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[1] Daily (gal)	Maximum Operation[1] Annual (gal)	Control Efficiency[3]	Potential to Emit[2] Hourly, lb/hr	Potential to Emit[2] Daily, lb/day	Potential to Emit[2] Annual, tpy	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	0.66	g/hp-hr	320	53,760			7.88	0.66	0.041	0.019
NO_x	11.72	g/hp-hr	320	53,760			140.98	11.84	0.74	0.341
$PM_{2.5}$	0.288	g/hp-hr	320	53,760			3.46	0.29	0.018	0.008
PM_{10}	0.288	g/hp-hr	320	53,760			3.46	0.29	0.018	0.008
SO_2	0.000030	lb/lb	320	53,760			0.07	5.71E-03	3.57E-04	1.64E-04
VOC	2.98	g/hp-hr	320	53,760			35.85	3.01	1.88E-01	8.66E-02
Lead	0.000029	lb/MMBtu	320	53,760			1.24E-03	1.04E-04	6.48E-06	2.98E-06

Emissions Factor References

CO	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
NO_x	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
$PM_{2.5}$	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 25
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	Maximum emission factor from all cementing unit and logging winch engines - see Reference Table 2, page 25
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

453.59	g/lb	
2,000	lbs/ton	
745.7	watts/hp	
7.076	lbs/gal	
133,098	Btu/gal	
0.415	lb/hp-hr	Fuel usage is minimum of values for five engines (FD16-20)

Footnotes/Assumptions

1 Daily fuel usage is per applicant request dated 9/17/2009: 320 gallons per day
2 Emissions are for all cementing unit and logging winch engines in aggregate.
3 Emission factors used on this page are controlled (either CDPF or Tier3)

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				

Hourly emissions are for one incinerator 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[5]		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
Base Case Scenario									**Base Case Scenario**		
CO	31	lbs/ton	1300	50,400		4.28	20.15	0.39	0.539	0.106	0.011
NO_x	5	lbs/ton	1300	50,400		0.69	3.25	0.06	0.087	0.017	0.002
$PM_{2.5}$	7.00	lbs/ton	1300	50,400		0.97	4.55	0.09	0.122	0.024	0.003
PM_{10}	8.2	lbs/ton	1300	50,400		1.13	5.33	0.10	0.143	0.028	0.003
SO_2	2.5	lbs/ton	1300	50,400		0.35	1.63	0.03	4.35E-02	8.53E-03	9.06E-04
VOC	3	lbs/ton	1300	50,400		0.41	1.95	0.04	5.22E-02	1.02E-02	1.09E-03
Lead	0.213	lbs/ton	1300	50,400		0.03	0.14	2.68E-03	3.70E-03	7.27E-04	7.72E-05
Alternative Scenario #1									**Alternative Scenario #1**		
CO	31	lbs/ton	800	50,400		4.28	12.40	0.39	0.539	0.065	0.011
NO_x	5	lbs/ton	800	50,400		0.69	2.00	0.06	0.087	0.01	0.002
$PM_{2.5}$	7.00	lbs/ton	800	50,400		0.97	2.80	0.09	0.122	0.015	0.003
PM_{10}	8.2	lbs/ton	800	50,400		1.13	3.28	0.10	0.143	0.017	0.003
SO_2	2.5	lbs/ton	800	50,400		0.35	1.00	0.03	4.35E-02	5.25E-03	9.06E-04
VOC	3	lbs/ton	800	50,400		0.41	1.20	0.04	5.22E-02	6.30E-03	1.09E-03
Lead	0.213	lbs/ton	800	50,400		0.03	0.09	2.68E-03	3.70E-03	4.47E-04	7.72E-05
Alternative Scenario #2									**Alternative Scenario #2**		
CO	31	lbs/ton	300	50,400		4.28	4.65	0.39	0.539	0.024	0.011
NO_x	5	lbs/ton	300	50,400		0.69	0.75	0.06	0.087	0.004	0.002
$PM_{2.5}$	7.00	lbs/ton	300	50,400		0.97	1.05	0.09	0.122	0.006	0.003
PM_{10}	8.2	lbs/ton	300	50,400		1.13	1.23	0.10	0.143	0.006	0.003
SO_2	2.5	lbs/ton	300	50,400		0.35	0.38	0.03	4.35E-02	1.97E-03	9.06E-04
VOC	3	lbs/ton	300	50,400		0.41	0.45	0.04	5.22E-02	2.36E-03	1.09E-03
Lead	0.213	lbs/ton	300	50,400		0.03	0.03	2.68E-03	3.70E-03	1.68E-04	7.72E-05

Emissions Factor References

CO	AP-42 Table 2.2-1, multiple hearth
NO_x	AP-42 Table 2.2-1, multiple hearth
$PM_{2.5}$	Owner requested limit per Shell 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

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, and alternative scenarios are based on owner requested limits per Shell request dated 9/17/2009
5 Annual maximum waste incinerated is for all operating scenarios in aggregate, and is based on an av 300 lbs/day

Shell Offshore Inc.
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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

			Maximum Hours of Operation[2]			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	0.95	lb/MMBtu	12	96		1.94	23.30	0.09	0.245	0.122	2.68E-03
NO_x	4.41	lb/MMBtu	12	96		9.01	108.17	0.43	1.136	0.568	1.24E-02
$PM_{2.5}$	0.31	lb/MMBtu	12	96		0.63	7.60	0.03	0.080	0.040	8.75E-04
PM_{10}	0.31	lb/MMBtu	12	96		0.63	7.60	0.03	0.080	0.040	8.75E-04
SO_2	0.000030	lb/lb fuel	12	96		3.26E-03	0.04	1.56E-04	0.000	0	4.50E-06
VOC	0.35	lb/MMBtu	12	96		0.72	8.58	0.03	0.090	0.045	9.88E-04
Lead	0.000029	lb/MMBtu	12	96		5.93E-05	7.11E-04	2.85E-06	7.47E-06	3.73E-06	8.18E-08

Emissions Factor References

CO, NO_x, $PM_{2.5}$, PM_{10}, VOC From AP-42, Section 3.3, Table 3.3-1
SO_2 Based on fuel sulfur content: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

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

Footnotes/Assumptions

1 Equipment population and rating based on vessel Jim Kilabuk per permit application dated 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]: 28400 hp
Max. Aggregate Limit, Propulsion Engines[2]: 22720 hp
Aggregate Rating, Generation Engines[1]: 2800 hp
Max. Aggregate Limit, All Engines[2]: 19,030 kW mechanical kW
Max. Aggregate Limit, All Engines[3]: 17,508 kWe electrical kW

			Maximum Operation (kWe-hr)			Potential to Emit[3]			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	3.35	g/kW-hr	420,188	28,233,704		140.36	3,368.64	113.17	17.685	17.685	3.256
NO_x	5.876	lb/MMBtu	420,188	28,233,704		1049.69	25,192.53	846.38	132.258	132.258	24.347
$PM_{2.5}$	0.22	lb/MMBtu	420,188	28,233,704		39.30	943.22	31.69	4.952	4.952	0.912
PM_{10}	0.249	lb/MMBtu	420,188	28,233,704		44.48	1067.55	35.87	5.605	5.605	1.032
SO_2	0.000030	lb/lb	420,188	28,233,704		0.28	6.84	0.23	0.036	0.036	0.007
VOC	0.60	g/kW-hr	420,188	28,233,704		25.17	604.15	20.30	3.172	3.172	0.584
Lead	2.90E-05	lb/MMBtu	420,188	28,233,704		5.18E-03	0.12	4.18E-03	6.53E-04	6.53E-04	1.20E-04

Emissions Factor References
CO, VOC From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25
NOx Emission factors relied upon by Shell in 9/17/2009 submittal to establish annual, owner-requested emission limits
$PM_{2.5}$, PM_{10} Emission factors relied upon by Shell in 9/17/2009 submittal to establish daily, owner-requested emission limits
SO_2 Based on fuel sulfur content: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Aggregate Rating, Heat Boiler(s)[1]: 10.00 MMBtu/hr
Maximum Hourly Fuel Use[5]: 75 gallons/hour

			Maximum Hours of Operation			Potential to Emit			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	5	$lb/10^3$ gal	24	4,032		3.76E-01	9.02	0.76	0.047	0.047	0.022
NO_x	20.00	$lb/10^3$ gal	24	4,032		1.50E+00	36.06	3.03	0.189	0.189	0.087
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		2.48E-01	5.95	0.50	0.031	0.031	0.014
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		2.48E-01	5.95	0.50	0.031	0.031	0.014
SO_2	0.213	$lb/10^3$ gal	24	4,032		1.60E-02	0.38	0.03	2.02E-03	2.02E-03	9.28E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		2.55E-02	0.61	0.05	3.22E-03	3.22E-03	1.48E-03
Lead	0.000009	lb/MMBtu	24	4,032		9.00E-05	0.00	1.81E-04	1.13E-05	1.13E-05	5.22E-06

Emissions Factor References
CO, NOx AP-42 Table 1.3-1, boilers < 100 MMBtu/hr
$PM_{2.5}$ Assumed to be same as for PM_{10}
PM_{10} AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)
SO_2 AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel: 0.000015 by weight
VOC AP-42 Table 1.3-3, commercial boilers
Lead AP-42, Table 1.3-10

Equipment Type: Incinerator
Aggregate Rating[1]: 154.00 lb/hr Emissions are for all incinerators on board the vessel

			Maximum Hours of Operation			Potential to Emit			Potential to Emit in g/sec		
Pollutant	Emission Factors	Emission Factor Units	Daily	Annual	Control Efficiency	Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	300	lbs/ton	24	4032		23.10	554.40	46.57	2.911	2.911	1.34
NO_x	3	lbs/ton	24	4032		0.23	5.54	0.47	0.029	0.029	0.014
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.70	16.82	1.41	0.088	0.088	0.041
PM_{10}	13.3	lbs/ton	24	4032		1.02	24.58	2.06	0.129	0.129	0.059
SO_2	2.5	lbs/ton	24	4032		0.19	4.62	0.39	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.70	184.80	15.52	0.97	0.97	0.446
Lead	0.213	lbs/ton	24	4032		1.64E-02	3.94E-01	3.31E-02	2.07E-03	2.07E-03	9.51E-04

Emissions Factor References
CO, NOx, SO_2, VOC AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}: Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Shell Offshore Inc.
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Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #1
(CONTINUED)

Total Emissions for Icebreaker #1

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
163.84	3932.06	160.50	20.643	20.643	4.617
1051.42	25234.14	849.88	132.476	132.476	24.448
40.25	965.99	33.60	5.071	5.071	0.967
45.75	1098.08	38.43	5.765	5.765	1.105
0.49	11.84	0.65	0.062	0.062	0.019
32.90	789.56	35.87	4.145	4.145	1.032
0.02	0.52	3.74E-02	2.73E-03	2.73E-03	1.08E-03

Conversions Used

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

Footnotes/Assumptions

1 Maximum equipment ratings per e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair):
Propulsion engines: 28400 hp at maximum 80% load
Generator engines: 2800 hp
Boilers: 10 MMBtu/hr
Incinerator: 154 lb/hr
2 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content
3 Minimum generator efficiency based on conservative data from Shell submittal to EPA dated 11/23/2009 (pages 6 - 7):
Engine minimum generator efficiency: 92%
4 Owner requested limits: PM2.5 hourly emissions limit: 42.2 lbs
PM10 hourly emissions limit: 48.0 lbs

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

Fleet Unit: Ice Breaker #2 - Tor Viking Scenario
Fuel: Liquid distillate, #1 or #2, and waste materials for incinerator

Equipment Type: Internal Combustion Engines
Aggregate Rating, Propulsion Engines[1]: 17660 hp
Max. Aggregate Limit, Propulsion Engines[2]: 14128 hp
Aggregate Rating, Generation Engines[1]: 2336 hp
Max. Aggregate Limit, All Engines[2]: 12,277 kW mechanical kW
Max. Aggregate Limit, All Engines[3]: 11,786 kWe electrical kW

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (kWe-hr) Daily	Annual	Control Efficiency	Potential to Emit[4] 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	282,867	18,058,216		90.55	2173.25	69.37	11.409	11.409	1.996
NO_x	0.106	lb/gal	282,867	18,058,216		91.78	2202.82	70.31	11.565	11.565	2.023
$PM_{2.5}$	0.0573	lb/MMBtu	282,867	18,058,216		6.60	158.49	5.06	0.832	0.832	0.146
PM_{10}	0.0573	lb/MMBtu	282,867	18,058,216		6.60	158.49	5.06	0.832	0.832	0.146
SO_2	0.000030	lb/lb	282,867	18,058,216		0.18	4.41	0.14	0.023	0.023	0.004
VOC	0.60	g/kW-hr	282,867	18,058,216		16.24	389.76	12.44	2.046	2.046	0.358
Lead	2.90E-05	lb/MMBtu	282,867	18,058,216		3.34E-03	0.08	2.56E-03	4.21E-04	4.21E-04	7.37E-05

Emissions Factor References

CO, VOC From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25

NOx Emission factors relied upon by Shell per 1/05/2010 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair) to establish annual, owner-requested emission limits

$PM_{2.5}$ Owner requested limits per 11/23/2009 submittal from Shell

PM_{10} Owner requested limits per 11/23/2009 submittal from Shell

SO_2 Based on fuel sulfur content: 0.000015 by weight

Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Aggregate Rating, Heat Boiler(s)[1]: 1.37 MMBtu/hr
Maximum Hourly Fuel Use[5]: 10 gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	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	5	$lb/10^3$ gal	24	4,032		5.15E-02	1.24	0.10	0.006	0.006	0.003
NO_x	20.00	$lb/10^3$ gal	24	4,032		0.21	4.94	0.42	0.026	0.026	0.012
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		0.03	0.82	0.07	0.004	0.004	0.002
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		0.03	0.82	0.07	0.004	0.004	0.002
SO_2	0.213	$lb/10^3$ gal	24	4,032		2.19E-03	0.05	4.42E-03	2.76E-04	2.76E-04	1.27E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		3.50E-03	0.08	0.01	4.41E-04	4.41E-04	2.03E-04
Lead	0.000009	lb/MMBtu	24	4,032		1.23E-05	2.96E-04	2.49E-05	1.55E-06	1.55E-06	7.15E-07

Emissions Factor References

CO, NOx AP-42 Table 1.3-1, boilers < 100 MMBtu/hr
$PM_{2.5}$ Assumed to be same as for PM_{10}
PM_{10} AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)
SO_2 AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel: 0.000015 by weight
VOC AP-42 Table 1.3-3, commercial boilers
Lead AP-42, Table 1.3-10

Equipment Type: Incinerator
Aggregate Rating[1]: 151.23 lb/hr Emissions are for all incinerators on board the vessel

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	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		22.68	544.43	45.73	2.858	2.858	1.315
NO_x	3	lbs/ton	24	4032		0.23	5.44	0.46	0.029	0.029	0.013
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.69	16.51	1.39	0.087	0.087	0.04
PM_{10}	13.3	lbs/ton	24	4032		1.01	24.14	2.03	0.127	0.127	0.058
SO_2	2.5	lbs/ton	24	4032		0.19	4.54	0.38	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.56	181.48	15.24	0.953	0.953	0.438
Lead	0.213	lbs/ton	24	4032		1.61E-02	3.87E-01	3.25E-02	2.03E-03	2.03E-03	9.34E-04

Emissions Factor References

CO, NOx, SO_2, VOC AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}: Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

Shell Offshore Inc.
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Criteria Pollutant Emission Inventory

Fleet Unit: Ice Breaker #2 - Tor Viking Scenario
(CONTINUED)

Total Emissions for Tor Viking

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
113.29	2718.91	115.20	14.274	14.274	3.314
92.22	2213.20	71.19	11.619	11.619	2.048
7.33	175.82	6.52	0.923	0.923	0.187
7.64	183.44	7.16	0.963	0.963	0.206
0.38	9.00	0.53	0.047	0.047	0.015
23.81	571.32	27.69	2.999	2.999	0.796
1.95E-02	0.47	3.51E-02	2.45E-03	2.45E-03	1.01E-03

Maximum Emissions for Icebreaker#2 (max of Tor Viking and Hull

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
234.48	5627.51	237.17	29.544	29.544	6.822
92.22	2213.20	71.19	11.619	11.619	2.048
11.37	272.87	11.15	1.433	1.433	0.321
11.69	280.49	11.79	1.473	1.473	0.339
0.51	12.19	0.68	0.064	0.064	0.019
23.81	571.32	27.69	2.999	2.999	0.796
2.14E-02	0.51	3.73E-02	2.69E-03	2.69E-03	1.07E-03

Conversions Used

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

Footnotes/Assumptions

1 Maximum equipment ratings per Shell submittal to EPA dated 9/17/2009:
Propulsion engines: 17660 hp at maximum
Non-propulsion Generator engines: 2336 hp
Boilers: 1.37 MMBtu/hr
Incinerator: 151.23 lb/hr
2 Maximum operating limit Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines, in aggregate: 80%
3 Minimum generator efficiency based on MaK engine specs per Shell submittal to EPA dated 11/23/2009 (Attachment B, page 14):
Propulsion engine minimum generator efficiency: 96%
4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content

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

Fleet Unit:	Ice Breaker #2 - Hull 247		
Fuel:	Liquid distillate, #1 or #2, and waste materials for incinerator		
Equipment Type:	Internal Combustion Engines		
Aggregate Rating, Propulsion Engines[1]:	24000	kW	mechanical kW
Max. Aggregate Limit, Propulsion Engines[2]:	19200	kW	mechanical kW
Max. Aggregate Limit, Propulsion Engines[3]:	17664	kWe	electrical kW

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation (kWe-hr) Daily	Maximum Operation (kWe-hr) Annual	Control Efficiency	Potential to Emit[4] Hourly, lb/hr	Potential to Emit[4] Daily, lb/day	Potential to Emit[4] Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	5.0	g/kW-hr	423,936	31,904,074		211.64	5,079.48	191.13	26.667	26.667	5.498
NO_x	1.8	g/kW-hr	423,936	31,904,074		76.19	1,828.61	68.81	9.6	9.6	1.979
$PM_{2.5}$	0.25	g/kW-hr	423,936	31,904,074		10.58	253.97	9.56	1.333	1.333	0.275
PM_{10}	0.25	g/kW-hr	423,936	31,904,074		10.58	253.97	9.56	1.333	1.333	0.275
SO_2	0.000012	lb/hp-hr	423,936	31,904,074		0.31	7.50	0.28	0.039	0.039	0.008
VOC	0.19	g/kW-hr	423,936	31,904,074		8.04	193.02	7.26	1.013	1.013	0.209
Lead	2.90E-05	lb/MMBtu	423,936	31,904,074		5.23E-03	0.13	4.72E-03	6.59E-04	6.59E-04	1.36E-04

Emissions Factor References

CO, NO_x, PM, VOC	Marine engine emission limits in 40 CFR 1042.101 (engines of at least 700 kW). All HC assumed to be VOC			
	Owner requested annual NOx limits per 9/17/2009 submittal from Shell			
$PM_{2.5}$, PM_{10}	$PM_{2.5}$ and PM_{10} emission factors assumed to be same as PM			
SO_2	AP-42 Table 3.4-1 and	Sulfur content of fuel:	0.000015	by weight
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45			

Aggregate Rating, Heat Boiler(s)[1]:	4.00	MMBtu/hr
Maximum Hourly Fuel Use[6]:	30	gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	Maximum Hours of Operation Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	5	$lb/10^3$ gal	24	4,032		0.15	3.6	0.30	0.019	0.019	0.009
NO_x	20.00	$lb/10^3$ gal	24	4,032		0.60	14.43	1.21	0.076	0.076	0.035
$PM_{2.5}$	3.30	$lb/10^3$ gal	24	4,032		0.10	2.38	0.20	0.012	0.012	0.006
PM_{10}	3.30	$lb/10^3$ gal	24	4,032		0.10	2.38	0.20	0.012	0.012	0.006
SO_2	0.213	$lb/10^3$ gal	24	4,032		6.40E-03	0.15	0.01	8.07E-04	8.07E-04	3.71E-04
VOC	0.34	$lb/10^3$ gal	24	4,032		0.01	0.25	0.02	1.29E-03	1.29E-03	5.93E-04
Lead	0.000009	lb/MMBtu	24	4,032		3.60E-05	8.64E-04	7.26E-05	4.54E-06	4.54E-06	2.09E-06

Emissions Factor References

CO, NOx	AP-42 Table 1.3-1, boilers < 100 MMBtu/hr		
$PM_{2.5}$	Assumed to be same as for PM_{10}		
PM_{10}	AP-42 Table 1.3-1 (filterable for PM) and AP-42 Table 1.3-2 (total condensible)		
SO_2	AP-42 Table 1.3-1, boilers < 100 MMBtu/hr a Sulfur content of fuel:	0.000015	by weight
VOC	AP-42 Table 1.3-3, commercial boilers		
Lead	AP-42, Table 1.3-10		

Equipment Type:	Incinerator		
Aggregate Rating[1]:	151.23	lb/hr	Emissions are for all incinerators on board the vessel

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation Daily	Maximum Hours of Operation Annual	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	300	lbs/ton	24	4032		22.68	544.43	45.73	2.858	2.858	1.315
NO_x	3	lbs/ton	24	4032		0.23	5.44	0.46	0.029	0.029	0.013
$PM_{2.5}$	9.1	lbs/ton	24	4032		0.69	16.51	1.39	0.087	0.087	0.04
PM_{10}	13.3	lbs/ton	24	4032		1.01	24.14	2.03	0.127	0.127	0.058
SO_2	2.5	lbs/ton	24	4032		0.19	4.54	0.38	0.024	0.024	0.011
VOC	100	lbs/ton	24	4032		7.56	181.48	15.24	0.953	0.953	0.438
Lead	0.213	lbs/ton	24	4032		1.61E-02	3.87E-01	3.25E-02	2.03E-03	2.03E-03	9.34E-04

Emissions Factor References

CO, NOx, SO_2, VOC	AP-42 Table 2.1-12, maximum of values for industrial/commercial and domestic single chamber
$PM_{2.5}$, PM_{10}:	Owner requested limits per 5/14/2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair).
Lead	AP-42, Maximum of uncontrolled values in Table 2.1-2, 2.1-8

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

Fleet Unit: Ice Breaker #2 - Hull 247
(CONTINUED)

Total Emissions for Hull 247

Potential to Emit			Potential to Emit in g/sec		
Hourly, lb/hr	**Daily, lb/day**	**Annual, tpy**	**One-Hour**	**24-Hour**	**365-Day**
234.48	5627.51	237.17	29.544	29.544	6.822
77.02	1848.48	70.48	9.704	9.704	2.027
11.37	272.87	11.15	1.433	1.433	0.321
11.69	280.49	11.79	1.473	1.473	0.339
0.51	12.19	0.68	0.064	0.064	0.019
15.61	374.74	22.52	1.967	1.967	0.648
2.14E-02	0.51	3.73E-02	2.69E-03	2.69E-03	1.07E-03

Conversions Used

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

Footnotes/Assumptions

1 Maximum equipment ratings per Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines: 24000 kW mechanical
Non-propulsion Generator engines: 0 hp
Boilers: 4 MMBtu/hr
Incinerator: 151.23 lb/hr
2 Maximum operating limit Shell submittal to EPA dated 9/17/2009 (Attachment A, page 23):
Propulsion engines, in aggrega 80%
3 Minimum generator efficiency based on Shell submittal to EPA dated 11/23/2009:
Propulsion engine minimum generator efficiency: 92%
4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr
5 Shell has requested an annual NOx limit of 58.39 tpy per 9/17/2009 submittal
6 Fuel usage converted based on boiler rating and fuel heat content.

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]:	7784 hp
Owner Requested Limit (Daily, Annual)[2]:	6344 hp — Emissions are for all engines in aggregate.
Maximum Hourly Fuel Use[2]:	334 gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation[4]		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr[1]	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	3.35	g/kW-hr	4	32		34.89	139.57	0.56	4.396	0.733	0.016
NO_x	25.40	g/kW-hr	4	32		264.92	1059.68	4.24	33.379	5.563	0.122
$PM_{2.5}$	1.54	g/kW-hr	4	32		16.06	64.25	0.26	2.024	0.337	0.007
PM_{10}	1.92	g/kW-hr	4	32		20.02	80.10	0.32	2.523	0.421	0.009
SO_2	0.000030	lb/lb	4	32		0.07	0.28	1.13E-03	0.009	0.001	0
VOC	0.60	g/kW-hr	4	32		6.26	25.03	0.10	0.788	0.131	0.003
Lead	0.000029	lb/MMBtu	4	32		1.29E-03	5.16E-03	2.06E-05	1.62E-04	2.71E-05	5.93E-07

Emissions Factor References

All pollutants except lead From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25

SO_2 Sulfur content of fuel: 0.000015 by weight

Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Conversions Used

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

Footnotes/Assumptions

1 Equipment population and rating based on vessel Jim Kilabuk per permit application dated February 23, 2009, Appendix B, page 15
Propulsion Engines: 7200 hp
Both generators: 584 hp
Bow thrusters not used: 0 hp
7784 hp

2 Owner requested limits per e-mail and attachments of 5/14/2009 from Air Sciences (Rodger Steen) to EPA (Pat Nair) and 5/27/2009 phone call between Air Sciences (Rodger Steen) and EPA (Pat Nair):
Propulsion Engines limited to 2 engines at no more than 80% load, i.e. 5760 hp
Both generators at full load - total hp: 584 hp
Bow thrusters not used: 0 hp

3 Brake specific fuel combustion from AP-42: 7000 Btu/hp-hr

4 Owner requested limits per 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 5
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 kW

			Maximum Operation (gallons)[2]			Potential to Emit			Potential to Emit in g/sec		
Pollutant	**Emission Factors**	**Emission Factor Units**	**Daily**	**Annual**	**Control Efficiency[5, 6]**	**Hourly, lb/hr[3]**	**Daily, lb/day**	**Annual, tpy**	**One-Hour**	**24-Hour**	**365-Day**
CO	0.73	g/kW-hr	3,000	504,000	0.9	0.87	7.57	0.64	0.11	0.04	0.018
NO_x	13.62	g/kW-hr	3,000	504,000		162.70	1412.02	118.61	20.5	7.413	3.412
$PM_{2.5}$	0.17	g/kW-hr	3,000	504,000	0.85	0.30	2.64	0.22	0.038	0.014	0.006
PM_{10}	0.17	g/kW-hr	3,000	504,000	0.85	0.30	2.64	0.22	0.038	0.014	0.006
SO_2[2,4]	0.000030	lb/lb fuel	3,000	504,000		0.07	0.64	0.05	0.009	0.003	0.00
VOC	0.99	g/kW-hr	3,000	504,000	0.9	1.18	10.27	0.86	0.149	0.054	0.025
Lead	0.000029	lb/MMBtu	3,000	504,000		1.33E-03	1.16E-02	9.73E-04	1.68E-04	6.08E-05	2.80E-05

Emissions Factor References
CO, NO_x, $PM_{2.5}$, PM_{10}, VOC Permit application dated February 23, 2009, Appendix B, page 51
NOx NOx emission factor was converted from NO to NO2, ra 1.53
SO_2 Sulfur content of fuel: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Equipment Type: Non-Propulsion Generator Engines
Aggregate Rating[1]: 2570 hp
Owner Requested Limit (Daily, Annual)[2]: 800 gal/day

			Maximum Operation (gallons)[2]			Potential to Emit			Potential to Emit in g/sec		
Pollutant	**Emission Factors**	**Emission Factor Units**	**Daily**	**Annual**	**Control Efficiency[5, 6]**	**Hourly, lb/hr**	**Daily, lb/day**	**Annual, tpy**	**One-Hour**	**24-Hour**	**365-Day**
CO	3.35	g/kW-hr	800	134,400	0.9	1.41	8.37	0.70	0.178	0.044	0.02
NO_x	25.40	g/kW-hr	800	134,400		107.32	635.21	53.36	13.522	3.335	1.535
$PM_{2.5}$	1.54	g/kW-hr	800	134,400	0.85	0.98	5.78	0.49	0.123	0.03	0.014
PM_{10}	1.92	g/kW-hr	800	134,400	0.85	1.22	7.20	0.60	0.153	0.038	0.017
SO_2	0.000030	lb/lb fuel	800	134,400		2.87E-02	1.70E-01	1.43E-02	0.004	0.001	0.00
VOC	0.60	g/kW-hr	800	134,400	0.9	0.25	1.50	0.13	0.032	0.008	0.004
Lead	0.000029	lb/MMBtu	800	134,400		5.22E-04	3.09E-03	2.59E-04	6.57E-05	1.62E-05	7.46E-06

Emissions Factor References
All pollutants except lead and SO_2 From maximum of AP-42, Section 3.4, Table 3.4-1 or IVL and Lloyd's data from Verification of Ship Emission Estimates with Monitoring Measurements to Improve Inventory Modeling, Final Report Prepared for California Air Resource Board, by James J. Corbett, 23 November 2004 - see page 25
SO_2 Sulfur content of fuel: 0.000015 by weight
Lead Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Equipment Type: Incinerator
Aggregate Rating[1]: 125.00 lb/hr Emissions are for all incinerators on board the vessel

			Maximum Hours of Operation			Potential to Emit			Potential to Emit in g/sec		
Pollutant	**Emission Factors**	**Emission Factor Units**	**Daily**	**Annual**	**Control Efficiency**	**Hourly, lb/hr**	**Daily, lb/day**	**Annual, tpy**	**One-Hour**	**24-Hour**	**365-Day**
CO	300	lbs/ton	24	4,032		18.75	450.00	37.80	2.362	2.362	1.087
NO_x	3	lbs/ton	24	4,032		0.19	4.50	0.38	0.024	0.024	0.011
$PM_{2.5}$	9.1	lbs/ton	24	4,032		0.57	13.65	1.15	0.072	0.072	0.033
PM_{10}	13.3	lbs/ton	24	4,032		0.83	19.95	1.68	0.105	0.105	0.048
SO_2	2.5	lbs/ton	24	4,032		0.16	3.75	0.32	0.02	0.02	0.01
VOC	100	lbs/ton	24	4,032		6.25	150.00	12.60	0.787	0.787	0.362
Lead	0.213	lbs/ton	24	4,032		0.01	0.32	2.68E-02	1.68E-03	1.68E-03	7.72E-04

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

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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), and
Shell's updated request dated 9/17/2009:

Propulsion Engines expected to not exceed (in aggregate):	47000	kW-hr/day
Maximum fuel usage:	3000	gal/day
Generator usage expected to not exceed (in aggregate):	11,350	kW-hr/day
Maximum fuel usage:	800	gal/day

3 Fuel usage per permit application dated 2/23/2009, Appendix B, page 51 204.7 g/kW-hr

4 Fuel usage from AP-42, Section 3.3, brake specific fuel consumption from footnote c to Table 3.3.1
7000 Btu/hp-hr converted based on aggregate engine rating, and fuel density and heat content

5 PM10 control efficiency based on California Air Resources Board, Verification of Diesel Emission Control Strategies, 3/12/2009 (website), April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems, transmitted by April 27, 2009 e-mail from Air Sciences (Rodger Steen) to EPA (Pat Nair)

6 CO and VOC control efficiency from April 24, 2009 letter from CleanAIR Systems and April 20, 2007 quote from CleanAIR Systems,

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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	0.000030	lb/lb fuel	24	4,032		0.02	0	0.04	0.003	0.003	0.001
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	0.000030	lb/lb fuel	24	4,032		4.02E-04	1.00E-02	8.10E-04	0	0	0
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 population, 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: 0.000015 by weight

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Reference Table 1
Fuel Properties for Distillate Fuel Used on All Emission Units on the Discoverer

Fuel heat value:	133,098 Btu/gal	Keiser, Ronald email to Chris Tengco, 01/26/09, see permit application dated February 23, 2009, Appendix F, page 27.			
Fuel density:	847.9 kg/m^3	SCANRAFF-Vladimir Ignatjuk Certificate of Quality. 09/19/04.			
	7.076 lbs/gal	converted based on	453.59 g/lb	and	
			264.17 gal/m^3		

Reference Table 2
Comparison of Controlled Emission Factors for Cementing Units and Logging Winches

Pollutant	Detroit 8V71N Emission Factors cont. (g/hp-hr)	Detroit 3V-71 Emission Factors cont. (g/hp-hr)	John Deere Emission Factors, cont. (g/kW-hr)	John Deere Emission Factors, cont. (g/hp-hr)	Caterpillar C7 Emission Factors, cont. (g/kW-hr)	Caterpillar C7 Emission Factors, uncont. (g/hp-hr)	Maximum Emission Factor	Emission Factor Units
CO	0.299	0.66	0.55	0.41	0.70	0.52	0.66	g/hp-hr
NO_x	9.81	11.72	7.5	5.59	4.0	2.98	11.72	g/hp-hr
$PM_{2.5}$	0.19	0.29	0.09	0.07	0.03	0.02	0.29	g/hp-hr
PM_{10}	0.19	0.29	0.09	0.07	0.03	0.02	0.29	g/hp-hr
VOC	0.148	0.20	0.75	0.56	4.0	2.98	2.98	g/hp-hr

SO_2 emissions not compared as they are based on mass balance

Reference Table 3
Comparison of Emission Factors for Marine Engines

Pollutant	AP-42 Section 3.4 lb/hp-hr	g/kW-hr	IVL g/kW-hr	Lloyd's g/kW-hr	Maximum EF g/kW-hr
CO	5.50E-03	3.35	1.4	1.6	3.35
NO_x[5]	0.056	25.40	18.1	17	25.40
$PM_{2.5}$	0.00056	0.34	1.54		1.54
PM_{10}	0.00058	0.35	1.92	1.5	1.92
SO_2[5]	1.2135E-05	0.01	0	0.798	0.80
VOC	0.000705	0.43	0.6	0.5	0.60

Reference Table 4
Comparison of Emission Factors for
Marine Engines and External Combustion

Pollutant	Marine Engine EF g/kW-hr	Marine Engine EF[1] $lb/10^3$ gal	AP_42 Section 1.3 Tables 1 to 3 $lb/10^3$ gal	Maximum EF $lb/10^3$ gal
CO	3.35	104.58	5	104.58
NO_x[5]	25.40	794.01	20.00	794.01
$PM_{2.5}$	1.54	48.14	3.30	48.14
PM_{10}	1.92	60.02	3.30	60.02
SO_2[5]	0.80	24.94	26.98	26.98
VOC	0.60	18.76	0.34	18.76

1 Conversions based on 745.7 watts/hp
453.59 g/lb
Brake specific fuel consumption: 7000 Btu/hp-hr

Exhibit 5
AEWC & ICAS

APPENDIX B

ORIGINAL MODELING RESULTS FOR SECONDARY OPERATING SCENARIOS: ADJUSTED FOR CHANGES TO PRIMARY OPERATING SCENARIO #1 AND WITH MOST RECENT BACKGROUND LEVELS

Table 1
Secondary Operating Scenario #1 and #2 Predicted [d] Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Existing (µg/m³)	Scenario [a] SOS #1 Predicted [d] (µg/m³)	Scenario [a] SOS #1 Total [b] (µg/m³)	Scenario [a] SOS #2 Predicted [d] (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	91	18.92	109.92	19.40	110.40	150	73.60
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	11	18.50	29.50	18.40	29.40	35	84.29
	Annual						15	

Reference: Shell 5/29/09 Rev. App.; Environ 7/15/09-PM10; Environ 7/15/09-PM2.5; Environ 7/16/09 Bow Washing1; Environ 7/16/09-Bow Washing2.

a. SOS #1: 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.
d. Predicted values have been adjusted to reflect the reduction in PM_{10} and $PM_{2.5}$ impacts from POS #1.

Exhibit 5
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Table 2

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

Air Pollutant	Averaging Period	Existing ($\mu g/m^3$)	Scenario [a] SOS #3 Predicted [d] ($\mu g/m^3$)	Scenario [a] SOS #3 Total [b] ($\mu g/m^3$)	Scenario [a] SOS #4 Predicted [d] ($\mu g/m^3$)	Scenario [a] SOS #4 Total [b] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent [c]
Sulfur Dioxide (SO_2)	3-Hour	17	68.80	85.80	68.80	85.80	1300	6.60
	24-Hour	10	26.80	36.80	26.80	36.80	365	10.08
	Annual	0.5	2.00	2.50	2.00	2.50	80	3.13
Nitrogen Dioxide (NO_2)	Annual	2.0	18.20	20.20	18.20	20.20	100	20.20
Carbon Monoxide (CO)	1-Hour	1050	396.60	1446.60	396.60	1446.60	10000	14.47
	8-Hour	941	356.90	1297.90	356.90	1297.90	40000	3.24
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	91	19.40	110.40	19.40	110.40	150	73.60
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	11	18.40	29.40	18.40	29.40	35	84.00
	Annual	2.8	1.30	4.10	1.30	4.10	15	27.33

Reference: Shell 5/29/09 Rev. App.

a. SOS #3: Supply ship replenishment of 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.

d. Predicted values have been adjusted to reflect the reduction in impacts from POS #1.

Exhibit 5
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Table 3
Secondary Operating Scenario #5 and #6 Predicted Total Concentration Impact Comparison with NAAQS

Air Pollutant	Averaging Period	Existing (µg/m³)	Scenario [a,b] SOS #5 Predicted [e] (µg/m³)	Scenario SOS #5 Total [c] (µg/m³)	Scenario SOS #6 Predicted [e] (µg/m³)	Scenario SOS #6 Total [c] (µg/m³)	NAAQS (µg/m³)	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	91	26.10	117.10	26.10	117.10	150	78.07
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)	24-Hour	11	17.07	28.07	17.07	28.07	35	80.20
	Annual						15	

Reference: Environ 7/15/09-PM10; Environ 7/15/09-PM2.5; Environ 7/16/09 Bow Washing1; Environ 7/16/09-Bow Washing2.

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.
e. Predicted values do not reflect the reductions in PM_{10} and $PM_{2.5}$ emissions since the original proposal.

Table 4
Secondary Operating Scenario Predicted [c] 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			68.80	68.80			512	13.44
	24-Hour			26.80	26.80			91	29.45
	Annual			2.00	2.00			20	10.00
Nitrogen Dioxide (NO_2)	Annual			18.20	18.20			25	72.80
Particulate Matter equal to or less than 10 microns (PM_{10})	24-Hour	18.92	19.40	19.40	19.40	26.10	26.10	30	87.00
	Annual			1.90	1.90			17	11.18
Particulate Matter equal to or less than 2.5 microns ($PM_{2.5}$)								[b]	

Reference: Shell 5/29/09 Supp. App.

a. Percent of highest prediction amongst the six scenarios.
b. EPA has not promulgated $PM_{2.5}$ increments.
c. Predicted values have been adjusted to reflect the reduction in impacts from POS #1.

Exhibit 5
AEWC & ICAS